January 17, 2014

VIA ELECTRONIC FILING

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

Re: ISO New England Inc. and New England Power Pool,
Filings of Performance Incentives Market Rule Changes;
Docket No. ER14- -000

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act, ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee, hereby submits with this cover transmittal letter two alternative versions of Market Rule changes intended to improve the operating performance of capacity resources in New England.[1] One version is advocated by the ISO, the other by NEPOOL. Together, the ISO and NEPOOL join in asking the Federal Energy Regulatory Commission (the "Commission") to choose between these two alternatives.

The ISO and NEPOOL proposals are being submitted pursuant to Section 11.1.5 of the Participants Agreement (referred to as the "jump ball provision"). Section 11.1.5 requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant Vote of at least 60 percent in detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission may choose to "adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable." The Commission cannot adopt another

[1] Capitalized terms used but not defined in this cover letter are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

proposal not supported by either the ISO or NEPOOL unless it concludes first that neither of those two proposals satisfies the standard for acceptance under the Federal Power Act.[2]

The ISO Materials Submitted for this Filing

The ISO's proposal is being submitted to the Commission in two parts. Due to technical limitations associated with the Commission's eTariff system, the ISO is not able to submit multiple changes to the same Tariff section that have different effective dates in one submission. Accordingly, the first part of the ISO's overall submission includes the Tariff changes that are proposed to become effective on June 1, 2014, and the second part of the ISO's overall submission includes the Tariff changes that are proposed to become effective on June 1, 2018. The explanation and supporting materials for all of the Tariff changes is contained in the first submission. Although the ISO's overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the ISO's submissions as a single filing.

In the first part of its overall submission, the ISO is submitting materials in Attachments I-1a through I-1j. These materials include a transmittal letter that describes the ISO's proposed Tariff changes, as well as the testimony of Peter Brandien, Matthew White, Peter Cramton, David LaPlante and Seyed Parviz Gheblealivand, and Marc Montalvo in support of the ISO's proposal. The ISO materials also include the affidavit of Todd Schatzki of the Analysis Group Inc. ("Analysis Group") along with a report by Analysis Group entitled "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives." Finally, the materials include the Tariff sheets for the Tariff changes that are proposed to become effective on June 1, 2014. In the second part of its overall submission, the ISO is submitting materials in Attachments I-2a through I-2c. These materials include a cover letter explaining the reasons for the two-part submission and the Tariff sheets for the Tariff changes that are proposed to become effective on June 1, 2018.

In its materials, the ISO satisfies the requirements in the jump ball provision by explaining the ISO's reasons for not adopting the NEPOOL proposal and by providing an explanation as to why the ISO's proposal is superior to the NEPOOL proposal.

The NEPOOL Materials Submitted for this Filing

The NEPOOL materials also are being submitted, like the ISO materials, in two parts. The first part is contained in Attachments N-1a through N-1h include: (i) the NEPOOL transmittal letter containing an explanation of the NEPOOL proposal, including a discussion of why the NEPOOL proposal is preferable to the ISO proposal and should be accepted by the Commission; (ii) testimony of Peter D. Fuller, Director of Regulatory Affairs, NRG Energy Inc., East Region; testimony of Calvin A. Bowie, NEPOOL Transmission Sector Representative; testimony of Brian E. Forshaw, Chief Regulatory and Risk Officer, Connecticut Municipal Electric Energy Cooperative; testimony of Elin S. Katz, Consumer Counsel, Connecticut Office

[2] *Cf. Southern California Edison Co., et al*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995).

of Consumer Counsel; and affidavit and report of Richard D. Tabors, Ph.D., all on behalf of NEPOOL; (iii) a summary of the stakeholder process that resulted in a vote of 80.28% in support of the NEPOOL proposal; (iii) a tabulation of the votes taken by the Participants Committee at its the December 6, 2013 meeting with respect to the NEPOOL and ISO proposals; and (iv) blacklined and clean Tariff sheets, included in Attachments N-1i through N-1j, reflecting the portion of the NEPOOL proposal proposed to become effective on June 1, 2014. Technical limitations associated with the Commission's eTariff system also preclude a single filing from having multiple changes to the same Tariff section that have different effective dates. Accordingly, the second part of the NEPOOL proposal, reflecting the Tariff changes that are proposed to become effective on June 1, 2018, are being included with Part 2 of the ISO's overall submission as Attachment N-2a through N-2c. These materials include a NEPOOL cover letter explaining the reasons for the two-part submission and the Tariff sheets for the Tariff changes in the NEPOOL proposal that are proposed to become effective on June 1, 2018. Again, like the ISO's proposal, although the NEPOOL's proposal is divided into two parts to accommodate the eTariff system, the Commission should treat the NEPOOL proposal as a single package.

Following this letter is a Table of Contents listing each attachment to this filing.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Part 2

Attachment I-1a

Transmittal letter on behalf of the ISO

January 17, 2014

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

RE: ISO New England Inc., and New England Power Pool, Filings of Market Rule Changes To Implement Pay For Performance in the Forward Capacity Market; Docket No. ER14- -000 (Part 1 of 2)

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. (the "ISO") hereby electronically submits this transmittal letter and revised Tariff provisions to modify the Forward Capacity Market ("FCM").[2] The incentive structure in the FCM design must be significantly improved to address real, pervasive, and escalating resource performance problems that pose a serious threat to the reliable operation of the system. The capacity market must compensate resource owners for needed investments in reliability, while not continuing to pay resources that do not perform. The revised approach, dubbed "Pay For Performance," will strongly link capacity payments to resource performance during scarcity conditions.

The New England Power Pool ("NEPOOL") Participants Committee did not support the Pay For Performance Tariff changes. NEPOOL did, however, garner sufficient support for an alternative approach to invoke the "jump ball" provisions in Section 11.1.5 of the Participants Agreement. Hence, the NEPOOL alternative is presented in a separate part of this filing package. The NEPOOL proposal – which centers on a small increase to the energy price during scarcity conditions and changes to the FCM rules that further weaken the already ineffective incentive

[1] 16 U.S.C. § 824d (2006 and Supp. II 2009).

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement.

structure – simply will not provide either the incentives nor the consequences necessary to induce needed investment in reliable performance. The ISO's Pay For Performance approach, on the other hand, is a comprehensive solution to the identified problems; it will pay resources that perform well more than under the current design, while imposing real consequences if they fail to deliver what consumers have paid for.

I. INTRODUCTION

When sellers can depend on payment regardless of the quality of the product delivered, quality tends to suffer. When payments reward higher quality, quality tends to improve. While there have been many efforts to refine the FCM over the years, its design has always failed to reflect these most basic principles, and reliability in New England is deteriorating as a result.

Much of the reason for the FCM's failure in this regard is its complexity. The product is poorly defined; while the region requires resources that reliably provide energy and reserves when supply is scarce, the FCM instead buys something only vaguely related to that, called "availability." The FCM applies different rules and different standards to different types of resources (even though it seeks to buy the same product from all of them), and includes numerous one-off provisions and exceptions. And at the end of the day, capacity "obligations" mean little because there are rarely financial consequences for failing to perform.

Each of these elements of the current FCM is contrary to sound market design. This is not surprising, however, because the core FCM design was not based on any standard market model. Rather, the FCM was built from the ground up, without a blueprint, through a long series of negotiations and compromises. The result is an idiosyncratic design that is failing to meet its most basic objectives – ensuring reliability in a cost-effective manner. The solution to these problems is assuredly not more of the same. The FCM design must be fixed on a fundamental level.

The Pay For Performance design presented here replaces the FCM's esoteric design with one that is familiar. Pay For Performance is a true, two-settlement forward market, following a blueprint that has been tested, refined, and applied successfully in myriad other markets, including New England's own energy markets. Pay For Performance is built around a well-defined product – the delivery of energy and reserves when they are needed most. Its rules are much more simple than the current FCM design, and those rules apply in the same manner to all resource types, without exceptions. With greater transparency and less uncertainty, Pay For Performance will create strong incentives for resource performance consistent with the goals of the capacity market.

II. EXECUTIVE SUMMARY

In the current FCM design, capacity payments are poorly linked to resource performance. In many cases, capacity resources are being paid for simply existing, rather than for actually performing when they are needed. With the linkage between payments and performance broken, there is little incentive for resource owners to make investments to ensure that their resources will be ready and able to provide energy and reserves when needed. The lack of such investment is posing serious threats to the reliable operation of the system.

Indeed, as fully detailed in the testimony of Peter Brandien, the ISO's Vice President of Operations,[3] the ISO has observed and documented pervasive and worsening performance problems among the existing generation fleet in New England. These problems, which are not limited to a single resource or fuel type, fall into three general categories. First, the region's growing dependence on natural gas leaves it extremely vulnerable to interruptions in gas supply, which can occur with little notice and which can affect multiple generators simultaneously. Second, a significant portion of New England's oil and coal units cannot provide reliable backup when gas problems arise due to increased outage rates, start-up problems, and other operational difficulties. Third, across the entire fleet, the ISO is observing increasing outage rates, poor responses to contingencies, and a host of other issues, such as failure to maintain liquid oil inventory, mothballing dual fuel capability, and inadequate staffing.

Many of these problems could be resolved if suppliers undertook additional operational-related investments, whether in dual-fuel capabilities, short-notice or non-interruptible gas supply agreements, liquefied natural gas, new fast-responding demand response assets, comprehensive maintenance, resource upgrades to provide faster starts, or other arrangements to similar effect. However, the present FCM design provides little incentive for suppliers to invest in secure fuel arrangements or to undertake other investments that would assure their resources will perform when needed.

In the current FCM, the consequences for non-performance are negligible. As an initial matter, even with recent revisions to the definition, Shortage Events are extremely rare. A supplier that is confident that the performance of its resource will rarely be measured is unlikely to feel a strong incentive to take steps to ensure the resource's ability to perform. Furthermore, the current rules include numerous exemptions, under which resources are considered "available" during a Shortage Event even when they do not provide any energy or reserves whatsoever. A supplier that receives its full capacity payment while providing no energy or reserves is unlikely to see the need to invest in the ability of its resource to perform. Finally, even where a capacity resource *is* exposed to penalties under the current design, those penalties are

[3] *See* Testimony of Peter Brandien on behalf of the ISO, submitted with this filing as Attachment I-1b ("Brandien Testimony").

capped such that there can be no net loss on FCM obligations, no matter how poorly the resource performs; participation in the current FCM essentially constitutes a free option. A supplier that cannot lose money for failure to perform as obligated is poorly incented to meet its obligations.

These problems clearly demonstrate that an individual supplier does not face the proper incentives to make investments to ensure that its resource can and will perform as needed. But there is an even graver implication when looking at the cumulative effects of these problems on the quality of the region's fleet over time. The "money for nothing" nature of the current FCM design results in adverse selection of capacity resources. It encourages resources that are likely to be poor performers to participate in the market when they should exit. Resources with lower going-forward costs and relatively poor performance clear in the Forward Capacity Auction instead of those with higher going-forward costs but better performance, even where the latter are more cost-effective. This structural bias towards clearing of less reliable resources in the FCM can only lead to serious reliability problems on the system, and is of course contrary to the goals of good capacity market design.

For all of these reasons, capacity payments must be linked to actual performance during scarcity conditions. Moreover, payments and performance must be linked as directly as possible; simply increasing the severity of the current penalties would not suffice.

The central purpose of the capacity market is to provide financial incentives for participants in New England's restructured electricity system to build and maintain the resources necessary to assure reliable service. The region developed the FCM in recognition of critical shortcomings in the energy market, which result in insufficient financial incentives for such investment. In effect, the energy market is "missing" a portion of the revenue stream that properly functioning, uncapped competitive markets normally provide to investors to ensure that no demand goes unserved at the prevailing price. If this "missing" revenue stream is not replaced by the capacity market, suppliers could not expect to recover their total costs and would not enter the marketplace – or will soon exit. In that event, additional demand would go un-served and reliable service would not be achieved. A central objective of the FCM is to create a revenue stream that replaces the "missing" revenue stream, and to thereby induce suppliers to undertake the investments necessary for reliable electric service.

But it is not enough to simply calculate the amount of the missing revenue and give that amount to suppliers; if it were the current design would be adequate. In a fully functioning and uncapped energy market, the "missing" revenue would be paid only to resources that are actually providing energy or reserves during periods of scarcity. It would not simply pay out that revenue to all resources that exist or that are conceptually "available." Having that money paid for actual performance during periods of scarcity is precisely what incents resource owners to make investments to ensure that their resources will be ready and able to provide energy or reserves

during those periods. To be effective, the capacity market must replicate the performance incentives that would exist in a fully functioning and uncapped energy market by linking payments to performance during scarcity conditions. Without this linkage, individual suppliers lack the incentive to make investments that ensure their resources can perform when needed most. And worse, precisely because they have not made such investments, these less-reliable resources become *more* likely to clear in future Forward Capacity Auctions because they can offer at lower prices than resources that are more reliable and more expensive (but more cost-effective, from a reliability viewpoint). This creates a structural bias in the FCM to clear less-reliable resources, which over time is eroding reliability.

The Pay For Performance design presented here is a straightforward solution to these difficult problems. The Pay For Performance design is based on the two-settlement logic generally used in forward markets. This entails two key elements: First, a forward position in which a quantity of capacity is obligated, or sold. Each MW is paid at the auction clearing price. This sale in the capacity auction creates a resource-specific physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during reserve deficiencies. Second, a settlement for deviations. If a resource delivers more than its share of the system's requirements during a reserve deficiency, it will be paid for that incremental production; if it delivers less than its share, it will "buy out" of its position by paying other resources that did deliver. Positive and negative deviations are paid/charged at the same pre-specified rate, which is specified in the Tariff.[4] The two-settlement approach is completely standard in forward contracts, both for electricity and commodities ranging from oil to pork bellies to iron ore. In fact, the two-settlement design underlies the design of New England's Day-Ahead and Real-Time electricity markets, and is well understood by stakeholders.

Consumers will pay the auction clearing price to all resources that clear in the auction. Resources that provide more than their share of the system's requirements during scarcity events will be paid by those that provide less so that consumers will not bear the short-run risk of covering any unexpectedly high performance payments. This will continue to provide consumers with a predictable capacity price three years out, after the close of each Forward Capacity Auction. Having under-performers pay over-performers will also provide strong incentives for each resource to perform as needed, and for resources that can meet the system's needs by exceeding their share to benefit by doing so. These incentives will place performance risk on all FCM resources, and this risk will need to be priced in each resource's bid in future capacity auctions.

[4] The Capacity Performance Payment Rate must be specified in the Tariff because the absence of price-sensitive demand in the Real-Time Energy Market prevents determination of a market-clearing price when demand exceeds supply.

To provide the desired incentives, and hence to solve the problems identified above with the current FCM design, the Pay For Performance mechanism must be implemented without compromising the standard, efficient market principles typically embodied in a two-settlement mechanism. There are three market design principles that warrant special attention. First, a well-designed market must pay more for better performance and less for worse performance. Accordingly, a resource should earn its capacity market revenue based on the amount it delivers during scarcity conditions. Second, suppliers – and not consumers – must bear the risk and the rewards associated with their resources' performance. Hence, Pay For Performance includes no exemptions. This is a hallmark of competitive markets, and it places risk in the right place in order to incent investment by suppliers and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio. Third, the Pay For Performance design is resource neutral. In a well-designed market, two suppliers that provide the same good or service receive the same compensation. Their compensation is not dependent on what technology they use; it depends solely on whether they deliver the product.

If the Pay For Performance mechanism is implemented, it will provide numerous important benefits, which together should address the problems identified above. These benefits include:

- Operational-related investment. Strong performance incentives provide suppliers with the economic motivation, and the financial capability, for operational-related investments that ensure resources are available when needed to maintain reliability. This might include dual-fuel capability, short-notice or more reliable fuel supply arrangements, continuous staffing at resources, improved operating practices, more robust maintenance arrangements, shorter planned outages, incremental capital investments that shorten start times or increase ramp rates, rapid price-responsive demand behavior, and other improvements to similar effect.

- Cost-effective solutions. Markets motivate suppliers to deliver services in the most cost-effective ways. Pay For Performance will enable individual suppliers to select the solutions that work best for the technologies and features of their resources. This market-based approach rewards suppliers that pursue the most cost-effective means to improve performance and reliability.

- Efficient resource evolution. Stronger performance incentives will, over time, lead to a change in the capacity resource mix that directly improves system reliability at lowest cost. Resources that are unreliable and have high operating costs may submit higher offers into the Forward Capacity Auction, based on their expectation of performing poorly and experiencing negative performance payments during the commitment period. These resources will become less likely to clear the auction, relative to today. In contrast, the compensation provided for strong performance will enable highly efficient or highly flexible resources to profitably

make lower offers in the Forward Capacity Auction, and they will therefore be more likely to clear future capacity auctions.

The many features of the Pay For Performance design are discussed at length in the balance of this filing letter and in the attached testimony of the ISO witnesses:

- Witness Peter Cramton, Professor of Economics at the University of Maryland, provides a concise overview of the Pay For Performance design and its merits.

- ISO witness Peter Brandien, Vice President of Operations, describes in detail the resource performance problems that the ISO has been observing and the reliability implications of those problems.

- ISO witness Matthew White, Chief Economist, provides a detailed explanation of how the incentive structure in the current FCM design leads to precisely the types of performance problems actually observed, how capacity market incentives ought to be structured to avoid these problems, and how the Pay For Performance mechanism is designed to effectively solve these problems.

- The joint testimony of ISO witnesses David LaPlante, the Internal Market Monitor, and Seyed Parviz Gheblealivand, Economist, explains the changes to market monitoring and mitigation in the Pay For Performance design.

- Finally, ISO witness Marc Montalvo, Director of Enterprise Risk Management, explains revisions to the financial assurance provisions needed to implement Pay For Performance.

III. REQUESTED EFFECTIVE DATES

The majority of the Pay For Performance Tariff revisions will become effective on June 1, 2018, which is the start of the Capacity Commitment Period associated with the ninth Forward Capacity Auction. These include revisions to five separate sections of the Tariff: Section III.13 (the FCM rules); Section I, Exhibit IA (the Financial Assurance Policy); Section I.2 (defined terms); Section III.1 (minor changes to conform defined terms); and Section III.A.8 (minor changes to conform defined terms).

A smaller set of the Pay For Performance revisions will become effective on June 1, 2014, after the eighth Forward Capacity Auction is run but before the Existing Capacity Qualification Deadline for the ninth Forward Capacity Auction.[5] This is necessary because the

[5] The Existing Capacity Qualification Deadline for the ninth Forward Capacity Auction is June 2, 2014.

changes related to market monitoring and mitigation in the FCM must apply during the qualification process for the ninth Forward Capacity Auction. These include revisions to two separate sections of the Tariff: Section III.13 (the FCM rules); and Section I.2 (defined terms).

Because several sections of the Tariff (Section I.2, Section III.13.1, and Section III.13.2) each contain some revisions to be effective in 2014 and other revisions to be effective in 2018, this filing is being submitted in two parts.[6]

The ISO respectfully requests that the Commission issue an order no later than May 14, 2014 accepting the Pay For Performance design in its entirety, including all provisions to be effective in both 2014 and 2018. It is important that all of the rule changes are approved simultaneously because, although many of the rule changes will not be effective until 2018, those rule changes will significantly affect participation in the ninth Forward Capacity Auction, which will be conducted in February 2015, the qualification process for which will take place throughout the balance of 2014.

IV. DESCRIPTION OF THE ISO AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") 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 an RTO, 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 Council ("NERC").

All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

[6] This filing letter and its attachments are the first part of a two-part contemporaneous submission to the Commission. Due to technical limitations associated with the Commission's eTariff system, the ISO is not able to submit multiple changes to the same Tariff section that have different effective dates in one submission. Accordingly, the first part of the ISO's overall submission includes the revisions that are to become effective on June 1, 2014. The second part of the ISO's overall submission includes the revisions that are to become effective on June 1, 2018. The explanation and supporting materials for all of the Pay For Performance revisions is contained in the first submission. Although the ISO's overall filing has been divided into two parts to accommodate the eTariff system, the Commission should treat the submissions as a single filing.

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V. STANDARD OF REVIEW

The Tariff changes included in both the ISO proposal and the NEPOOL proposal are being submitted pursuant to the ISO's rights under Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[7] Section 11.1.5 of the Participants Agreement (referred to as the "jump ball" provision) requires that the ISO, as part of a Section 205 filing, present to the Commission any alternative Market Rule proposal that is approved by a Participant vote of at least 60 percent in detail sufficient to permit reasonable review by the Commission, explain the ISO's reasons for not adopting the proposal, and provide an explanation as to why the ISO believes its own proposal is superior to the proposal approved by the Participants Committee.

Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[8] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[9] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[10] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[11] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must

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

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

[9] *Id.* at 9.

[10] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

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

accept the Section 205 filing if it is just and reasonable.[12] This standard of review applies to both the ISO proposal and the NEPOOL proposal in terms of evaluating any other alternatives.

As discussed in the joint cover letter submitted by the ISO and NEPOOL, as between the ISO proposal and the NEPOOL proposal the Commission may choose to "adopt any or all of ISO's Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable." The Commission cannot adopt another proposal not supported by either the ISO or NEPOOL unless it concludes first that neither of those two proposals satisfies the standard for acceptance under the Federal Power Act summarized above.

VI. PAY FOR PERFORMANCE: RATIONALE AND DETAILED DESCRIPTION

A. There Are Serious Resource Performance Problems, And Poor Resource Performance Threatens The Reliable Operation Of The System

As described in the testimony of Mr. Brandien, New England is experiencing fleet-wide performance issues. Mr. Brandien concludes that the problems are so pervasive that they threaten the ISO's ability to operate the system reliably. He explains that these performance problems are not limited to a specific segment of the fleet, and are worsening.[13]

Specifically, gas-fired generators are not taking steps to assure availability of natural gas, of which there is simply not enough to supply both generators and other demand. These generators have limited access to alternatives like liquefied natural gas. Although the ISO's system operators are actively managing these issues, New England has experienced some sizeable reductions in generators' output as a result of gas supply interruptions. Because of the just-in-time nature of the gas supply, these reductions occur with little warning to the ISO.[14] Making this matter worse, generators are abandoning the dual-fuel capability of their units and no new dual fuel capability is being added. Operationally, where dual-fuel capability is available and operational on a gas-fired unit, it is a very effective substitute for unavailable gas. Seeing this capability decline is a very troubling development.[15]

The region turns to oil and coal generators when gas-fired generators are unavailable, but these resources have their own set of problems. As Mr. Brandien's testimony shows, oil- and coal-fired generators are the biggest contributors to underperformance relative to their Capacity

[12] *Cf. Southern California Edison Co., et al*, 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*)).

[13] *See* Brandien Testimony at 2-5.

[14] *See id.* at 6-24.

[15] *See id*. at 12.

Supply Obligations, reducing their economic maximum generation levels during the peak hours of peak days more than any other category of generator. These resources also have trouble starting on time (or at all), and their rate of unplanned outages is the highest in the fleet; they are unavailable on an unplanned basis more than 15 percent of the time that they are needed.[16]

While the problems with gas, oil, and coal units are significant, they are not the fleet's only performance problems. As Mr. Brandien notes, performance problems are truly fleet-wide, and include poor response to dispatch following a contingency, with an average response rate of only 71 percent. Increasing rates of unplanned outages are further evidence of deteriorating fleet-wide performance. The overall rate of unplanned outages across the entire New England generating fleet has more than doubled since 2007. Among other issues, generators of different types have failed to staff their units and, as a result, are unable to respond to dispatch in a contingency.[17]

While these performance issues are fleet-wide, gas supply is one of the core issues challenging reliability, given the region's increasing dependence on gas. However, even with additional gas infrastructure to improve supply, the region has a system that is dependent on gas and will be vulnerable to gas supply interruptions. This "systemic risk" may be realized in the event of one of a number of pipeline problems, which include maintenance, pressure problems, fuel quality problems, and operational flow orders during periods of high demand. During one of these events, multiple units that simultaneously draw from the pipeline could be affected, causing a correlated outage of multiple generators (including reserves). The scope of the potential problem is illustrated by the fact that a single pipeline can supply generators representing thousands of megawatts of electricity.[18]

In short, the region must have resources on which it can rely to perform, even following contingencies related to gas supply. As discussed below, the flawed incentive structure in the current FCM design has perpetuated these performance problems.

B. The Incentive Structure In The Current FCM Design Is Broken And Leads Directly To The Poor Performance That Is Observed

It is not a novel idea that incentives to motivate resource performance during scarcity conditions must be an important feature of the capacity market. As Dr. White explains, from its inception, the FCM has included provisions aimed at this goal.[19] The FCM currently includes a

[16] *See* Brandien Testimony at 26-36.

[17] *See id.* at 36-52.

[18] *See id.* at 22-24.

[19] Testimony of Matthew White on behalf of the ISO, submitted with this filing as Attachment I-1c ("White Testimony") at 13.

"Shortage Event" mechanism that imposes a financial penalty on resources that fail to be "available" during certain scarcity conditions. Generally, a "Shortage Event" is a period of thirty or more contiguous minutes during which the supply of energy and reserves is insufficient to meet the demand for energy and the real-time reserve requirements. Under the current FCM rules, for each Shortage Event, the ISO calculates an "availability score" for each resource having a Capacity Supply Obligation. The availability score, conceptually, is the resource's "available" MW divided by its Capacity Supply Obligation.[20]

With the benefit of experience, however, it is now clear that the Shortage Event mechanism is fundamentally flawed. Because of these flaws, the FCM not only fails to provide the necessary incentives to motivate suppliers to make investments that would ensure that they are able to perform during scarcity conditions, but in fact it creates strong *disincentives* for suppliers to do so. As a result, individual suppliers do not take needed steps to ensure the performance of their resources during scarcity conditions. And worse, these problems create a structural bias in the FCM to clear less-reliable resources. These consequences correlate directly with the problems observed with the New England fleet, as described above and in the testimony of Mr. Brandien.

There are two fundamental problems with the Shortage Event mechanism. First, basing capacity payments on a resource's "availability" is deeply flawed. Second, the mechanism includes numerous exemptions that remove almost all financial consequences for non-performance. There are other notable problems with the current design as well, including caps on performance penalties that undermine the incentive structure, and a penalty rate that is too low and needlessly complex. Each of these problems is explained in more detail below.

1. Basing Capacity Payments On "Availability" Is Deeply Flawed

For the FCM to achieve its goals, it must provide incentives for resources to perform – to actually deliver energy or reserves – during scarcity conditions. At bottom, "availability" is not the same thing as actually delivering energy or reserves, and basing capacity payments on "availability" will only incent availability, not actual performance. As an example, under the current FCM rules, a resource that is off line with a metered output equal to zero (but available for dispatch and following ISO dispatch instructions) and that has a ten-hour start-up time is deemed fully "available." If a scarcity condition occurs with little notice, such a resource can contribute nothing to restoring the system. Another resource that can start quickly will be called on to provide energy or reserves to address the problem. This more flexible resource that does contribute to restoring the system is also deemed fully "available." Both of these resources receive the same capacity payment.[21]

[20] *See* current Tariff Section III.13.7.1.

[21] *See* White Testimony at 15-24.

Making the same capacity payment to different resources that make very different contributions to system reliability is a terrible way to encourage resources to make investments that will allow them to contribute to system reliability. A resource that consistently delivers energy and reserves during scarcity conditions contributes greatly to system reliability and should be financially rewarded for that performance. A resource that is unable to deliver energy or reserves during scarcity conditions is less valuable, and should be paid less, regardless of whether it is nominally "available." Basing payments on a proper measure of performance will directly incent suppliers to make investments to enable their resources to contribute to system reliability during scarcity conditions.

Making the same capacity payment to resources that make different contributions to system reliability not only fails to provide the proper incentives, it may actually *discourage* the desired investments. This is because all resources face the possibility of an unforeseen start-up failure that might result in an availability penalty under the current rules. An inflexible resource that is rarely called to help during scarcity conditions faces fewer such potential penalties than a flexible resource that is frequently called to help at such times. The results can be perverse: a flexible resource that performs ably four times out of five, but has a failed start one time, receives *less* capacity revenue than the inflexible resource that is never even called because it cannot possibly help in any of the five events. Because the flexible resource has a higher likelihood of being penalized, it has higher expected costs associated with taking on a Capacity Supply Obligation. To cover these greater costs, the flexible unit would require a higher price in the Forward Capacity Auction. In effect, its flexibility – which should of course make it more valuable – not only reduces its expected profits due to the availability penalty mechanism, it makes it less likely to clear in the Forward Capacity Auction in the first place. This constitutes a strong disincentive to build flexible resources of any kind, which are often the most valuable resources to manage an unanticipated scarcity conditions.[22]

Even worse than its effects on the investment decisions for individual resources, however, is the effect of this exemption-laden, flawed availability-based performance metric on the New England fleet as a whole. Because resources that do not contribute to system reliability during scarcity conditions earn the same capacity payments as resources that do, it is profitable for resources with low costs and poor performance during scarcity conditions to remain in the capacity market. These low-cost, but poorly performing resources displace higher-cost, but better performing resources. These higher-cost resources, because they would contribute more to system reliability, are actually more cost-effective than the resources that displace them. In effect, then, the current FCM has a structural bias to select less-reliable resources, an outcome completely at odds with the goals of maintaining reliability in a cost-effective manner.[23]

[22] *See* White Testimony at 19-20.

[23] *See id.* at 21-22.

2. Exemptions For Non-Performance Are Incompatible With Sound Capacity Market Design

Another fundamental problem with the current Shortage Event mechanism is that it includes numerous exemptions under which resources that are not able to provide energy or reserves during a Shortage Event are nonetheless deemed fully "available." As a result they are not subject to capacity payment reductions, despite providing zero contribution to system reliability during the Shortage Event.

For example, a resource that is on a planned outage when a Shortage Event occurs will be deemed available up the MW amount submitted in the outage request.[24] A resource that is not committed due to an outage or derate of certain transmission equipment is considered fully available.[25] And an import capacity resource that is properly offered, but that cannot be delivered because the relevant external interface is constrained, is considered to be fully available.[26] Intermittent Power Resources are not subject to the Shortage Event provisions at all.[27] And, as already described, resources that are unable to help alleviate a scarcity condition due to lengthy startup times are considered fully available.[28] The economic effects of these exemptions will distort the mix of capacity resources in undesirable ways, and are contrary to sound capacity market design.

In similar ways to the "availability" problems discussed above, these exemptions break the important link between capacity payments and resource performance during scarcity conditions. If an exemption allows a resource that does not provide energy or reserves during scarcity conditions to collect the same capacity payment as a resource that does, the exempted supplier does not face strong incentives to invest in ways that can improve its resource's ability to deliver during those conditions. And when poor performance is excused and exempt from financial consequences, a poorly performing resource does not need to raise its bid price in the capacity auction to account for any expected penalties – but resources without the exemption do. This again skews the bids in the auction in an especially problematic way: It lowers bid prices from resources that expect to be poor performers and that expect to be exempt from the financial consequences for non-performance. As a result, the auction becomes more likely to clear these poor-performing, less-reliable resources. At bottom, selling capacity becomes an 'empty' obligation when non-performance is exempt from any financial consequence.[29]

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[24] *See* Tariff Section III.13.7.1.1.4(b).

[25] *See* Tariff Section III.13.7.1.1.3(f).

[26] *See* Tariff Section III.13.7.1.2(d).

[27] *See* Tariff Section III.13.7.1.3.

[28] *See* Tariff Section III.13.7.1.1.3(c).

[29] *See* White Testimony at 24-29.

Importantly, exemptions are equally problematic, and equally inappropriate, in cases where the non-performance is arguably not the fault of the supplier. The market design must allocate the risks and costs of non-performance either to suppliers or to consumers. While suppliers may argue that some causes of poor performance are not their fault, it does not mean that consumers – who are even less likely to be at fault for the supplier's non-performance – should bear those risks and costs.[30]

In fact, it is sound market design for suppliers to bear the risks of non-performance, regardless of fault. An important role of the capacity market is to award Capacity Supply Obligations to resources that can be expected to contribute to reliability during scarcity conditions. To do so, a well-designed capacity market should lead a supplier to incorporate into its capacity offer price *all factors* that affect its ability to deliver during scarcity conditions, regardless of whether these factors are within or beyond its control. No other entity is better-positioned to price these factors. In this way, offers in the capacity market serve an essential role as price signals of both a resource's cost *and its reliability*. That property is crucial to efficient market design: It is what ensures that the capacity market does not award capacity obligations to resources that expect to perform poorly. Exemptions undermine this central role of prices as signals of resources' future performance and reliability.[31]

In a market designed in large part to help the region meet specific reliability objectives, exemptions are particularly damaging to the market's ability to achieve these objectives at least cost. For all of these reasons, exemptions are incompatible with sound capacity market design. They serve to destroy essential incentives, and inappropriately shift costs to those even less able to manage the risk.

3. Caps On Capacity Payment Reductions For Non-Performance Further Erode Performance Incentives

Another problem with the current FCM design is that penalties for non-performance are capped such that they cannot exceed the resource's total FCM revenue.[32] In other words, there is no way that a resource can lose money by taking on a Capacity Supply Obligation, even if it fails entirely to perform. This is contrary to sound market design, and is at odds with how two-settlement forward markets function.[33]

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[30] *See* White Testimony. at 27-29; *see also* Testimony of Peter Cramton on behalf of the ISO, submitted with this filing as Attachment I-1d ("Cramton Testimony") at 5-9.

[31] *See* White Testimony at 28-29.

[32] *See* current Tariff Section III.13.7.2.7.1.3.

[33] *See* White Testimony at 29-32.

The possibility of losing money as a result of taking on a Capacity Supply Obligation serves important purposes. It motivates suppliers to consider and price the reliability of their resources into their Forward Capacity Auction offers, such that only sellers that expect to be able to perform reliably take on an obligation. And once an obligation is assumed, the possibility of losing money motivates suppliers to take steps to ensure that their resources are able perform when needed.

The current FCM design breaks this basic precept of forward markets, such that poorly performing resources are not taking on a proper forward obligation. Rather, they are playing a game of "heads I win, tails I don't lose" with consumers' capacity payments. Economists call this a "free option problem." Providing free options is exceptionally poor market design, because they undermine essential performance incentives. They make it a worthwhile gamble for suppliers who rarely expect to perform to take on obligations because they have nothing to lose. Worse still, the free option problem helps make it profitable for even the poorest performing resources to remain in the capacity market, potentially displacing entry by more reliable resources that would be able to perform when needed.

4. The Penalty Rate In The Current FCM Rules Is Needlessly Complex And Is Too Low To Be Effective

The penalty rate in the current FCM rules has a structure that defies economic logic. As explained by Dr. White, the formula in the current FCM rules that determines Shortage Event penalties[34] results in penalty rates that actually decrease, rapidly, as the length of the scarcity condition increases.[35] This makes little sense, as scarcity conditions with longer durations can be expected to occur when the system faces more severe challenges meeting system energy and reserve requirements, and longer periods of heightened reliability risk. In effect, as scarcity conditions continue, the price signal for resources to perform plummets. This perverse property is difficult to reconcile with economic logic.[36]

In addition to their odd structure, the current penalty structure is needlessly complex. That makes the current FCM performance incentives lack transparency. It hampers the ability of investors to gauge whether additional capital expenditures to improve performance during scarcity conditions would be a profitable investment. For example, even if a resource owner has a reasonably informed view on how many hours, in total, the system may experience Shortage Events each year, that information is not enough to gauge its expected penalty for non-performance. The resource owner must also estimate the particular duration of *each* non-

[34] *See* current Section III.13.7.2.7.1.2

[35] *See* White Testimony at 33.

[36] *See id.* at 32-35.

contiguous Shortage Event during the year – likely an impractical task. This needless complexity impedes the ability for a resource owner to quantify whether investments that would improve the resource's performance during Shortage Events would yield a positive return, in the form of reduced penalties. In effect, its complexity undermines the very goals that these performance incentives are intended to serve.

Furthermore, the current Shortage Event penalty rate is generally low, and far too low to mirror the central principle of well-designed capacity market performance incentives. Over a broad range of possible Forward Capacity Auction clearing prices and scarcity condition durations, the effective penalty rate under the current mechanism is on the order of several hundred dollars per MWh. As Dr. White explains in detail,[37] to provide appropriate incentives for cost-effective investments, the marginal incentive to perform during scarcity conditions should be significantly larger than under the current rules – in some cases, by an order of magnitude. The low rate that presently applies to non-performance in the FCM directly undermines the financial incentives for resources to undertake capital investments to improve performance during scarcity conditions.

5. The Reliability Problems Actually Observed In New England Are Exactly What You Would Expect As A Result Of The Current Flawed Capacity Market Design

As explained by Dr. White, given the flawed incentives described above, and the resulting systematic bias towards clearing less reliable resources in the Forward Capacity Auctions, one would expect to see a deterioration of the reliability of the New England fleet over time, rather than the gradual improvement that would result from sound market design. And indeed, as detailed in the testimony of Mr. Brandien, the system's resources overall exhibit declining performance by a number of different measures. The system's operators no longer have confidence that resources will be able to perform when needed. This uncertain performance is manifest in many different ways and across a broad array of resource types and technologies. Moreover, a portion of the system's capacity resources have exhibited chronically poor performance during scarcity conditions, collecting capacity payments while doing little to assist with reliability during these periods of heightened risk. And it appears that these problems are getting worse, not better.[38]

[37] *See* White Testimony at 35.

[38] *See id.* at 46-48.

C. How A Well-Designed Capacity Market Should Be Structured To Address These Problems

Pay For Performance addresses each of the core problems described above, in a very straightforward manner. Instead of "availability," the FCM will allow consumers to procure the product that is needed in New England – resources that reliably provide energy and reserves when supply is scarce. There are no exemptions under Pay For Performance; consistent with sound market design, the reasons for non-performance are not relevant. Pay For Performance is resource-neutral and the same rules apply to all types of resources. The caps that currently ensure that a resource can never lose money in the FCM are replaced under Pay For Performance with a stop-loss mechanism that prevents unlimited risk exposure, but appropriately exposes poorly performing resources to potential losses. And under Pay For Performance, the rate at which deviations are settled is transparent and sufficiently high to incent the needed investments in resource performance.

As Dr. Cramton and Dr. White explain in detail in their respective testimonies, there is a simple logic to how performance incentives are achieved in markets.[39] During scarcity conditions, a supplier's payments should depend on what it actually delivers (energy and reserves) at the time. This logic is followed to good effect in the energy markets, and in many other types of markets, and must also be followed in the capacity market.

In markets other than for electricity, generally, when demand is less than supply, the competitive market price will be set at the incremental production cost of the most expensive supplier serving demand. When demand reaches or exceeds supply – that is, during scarcity conditions – the competitive market clearing price rises above the suppliers' incremental production costs. During such conditions, the price rises to the value that consumers place on the last unit produced; in other words, the price rises to what the market will bear. These higher prices during scarcity conditions play a critical role in properly functioning markets. Because prices fall close to marginal cost during non-scarcity conditions, suppliers in many markets must cover their total costs and earn the return on their investments based on what they deliver during scarcity conditions. This scarcity revenue (sometimes called scarcity "rent") provides a very strong motivation for suppliers to be able to deliver during scarcity conditions. This is the essential point: *Because such a critical portion of revenue is earned during scarcity conditions, suppliers are highly motivated to make cost-effective investments to assure they can deliver during scarcity conditions*.[40]

[39] *See* Cramton Testimony at 3-14; White Testimony at 35-46.

[40] *See id.* at 37-38.

Electricity markets generally behave like other markets when supplies are ample, but when supplies are tight, things are different. When electricity demand reaches the energy market's short-run capacity limit, the market price for energy is not determined by the value that consumers place on the last unit produced – it does not rise to the price that the market will bear. Instead, it continues to be set based on sellers' offers and the ISO's administrative pricing rules.

There are a number of reasons for this, but the root cause is that the demand side of electricity markets remains under-developed. For a host of technological, political, and regulatory reasons, the vast majority of electricity consumers are not exposed to real-time electricity prices. That is, consumers have neither the information (about real-time prices) nor the incentive to reduce their electricity consumption in response to scarcity conditions in the wholesale market. Without a natural demand-side response mechanism by consumers, there is no means for suppliers in the wholesale market to determine what price the market is willing to bear for the limited supply available during scarcity conditions.[41]

As a result, wholesale energy markets such as New England's have alternative mechanisms to set price during scarcity conditions. Specifically, during periods of scarcity the energy market price is determined by the offer price of the marginal supplier, plus an administratively-determined price adder. The adder, which is informally called a scarcity price (and in the Tariff is referred to as a Reserve Constraint Penalty Factor or "RCPF"), helps to replace the energy market's missing scarcity revenue during tight market conditions.

Unfortunately, this scarcity pricing mechanism is not flexible enough to equilibrate electricity supply and electricity demand during scarcity conditions. That is, the energy market's administrative price adders do not – and cannot – adjust the total energy price to ensure no demand goes un-served during scarcity conditions, as naturally occurs in other markets. The ISO cannot do this because it does not have the information this requires (there are insufficient demand-side bids in the Real-Time Energy Market), and because the absence of natural demand-side response by consumers means that electricity demand may not react as required. These shortcomings mean that even with administrative scarcity pricing in the energy market, electricity markets still face a reliability problem and an investment problem.[42]

The reliability problem is that electricity markets require administrative rules to assure consumers receive reliable service. Because electricity markets, with present technology, cannot reveal how much reliability consumers would prefer to purchase and at what price (because consumers cannot respond directly to price), consumers face the prospect that some of their demand for electricity may go un-served when supply is scarce. To limit the frequency with

[41] *See* White Testimony at 38-41.

[42] *See id*. at 40.

which this occurs, a reliability rule is necessary to determine the amount of reliability that consumers should receive. In New England, this administrative rule takes the form of the resource adequacy criterion.

The investment problem occurs because the energy market's scarcity revenue is too low to attract the level of investment necessary to achieve the reliability objective. If the scarcity revenue is too low, marginal suppliers will not expect to recover their total costs and will not enter the market (or will soon exit). In that case, additional demand will go un-served, undermining reliability further. Importantly, the scarcity revenue a seller may earn by producing at these times motivates the seller to do more than just install capacity; it motivates the seller to undertake cost-effective investments to ensure its capacity will perform reliably when demand is high or alternative sources of supply are scarce. Without these investments, the power system will also have poor reliability.

As Dr. White explains, at a fundamental level, capacity markets exist to remedy these shortcomings of the energy market.[43] There is no realistic fix to the energy or capacity market that will obviate the need for an administratively-determined reliability criterion, at least for the foreseeable future. A well-designed capacity market can simply and effectively achieve this reliability objective by enabling resources to earn the necessary scarcity revenue that the energy market does not provide.

However, it cannot pay out this revenue irrespective of resource performance. Doing so would eliminate the natural mechanism that scarcity revenue provides for encouraging investments that enable resources to perform reliably during scarcity conditions. Instead, the capacity market must pay out the scarcity revenue that the energy market fails to provide in the same way normal markets do – based on what resources provide during scarcity conditions. If that incentive structure is not replicated, then suppliers will not have the incentive to make the investments necessary to ensure that they are able to perform when needed most – during periods of scarcity.

In sum, a resource's capacity revenue must depend on its performance (actual delivery of energy or reserves) during scarcity conditions. Linking payments to performance is how properly functioning markets work, and rewards cost-effective capital expenditures in assets or capabilities that help ensure resources can perform during scarcity conditions, when reliability is at heightened risk. Moreover, linking payments to performance addresses the structural bias in the present FCM to clear less reliable resources. With proper rewards for reliable performance during scarcity conditions, more reliable, better performing resources can afford to submit lower bids in the capacity auction because of the additional performance-based revenue they obtain,

[43] *See* White Testimony at 42.

making them more likely to clear in the capacity auction. Less reliable, poorly performing resources cannot afford to submit lower bids in the capacity auction because the reduced capacity payments they receive will no longer cover their capacity costs. This makes poor performers less likely to clear in the capacity auction. Improving the capacity market's performance incentives will change which resources clear, selecting a better performing, more reliable fleet, rather than being biased toward less reliable resources.[44]

D. Core Concepts Of The Pay For Performance Design

1. The Central Principles Of The Pay For Performance Design

The Pay For Performance design adheres to three fundamental market design principles that characterize efficient, competitive markets. First, a well-designed market must pay more for better performance and less for worse performance. Accordingly, a resource should earn its capacity market revenue based on the amount it delivers during scarcity conditions. To do this, Pay For Performance replaces "availability" as the performance metric, and will instead measure actual energy and reserves provided during scarcity conditions.[45]

Second, suppliers – and not consumers – must bear the risk and the rewards associated with their resources' performance. Hence, Pay For Performance includes no exemptions. This is a hallmark of competitive markets, and it places risk in the right place, in order to incent investment by suppliers and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio. Suppliers are in the best position to manage their performance risk, whether those risks are within or beyond their control, through undertaking new investments to reduce their performance risk, or by making arrangements with other suppliers or entities to cover their obligations during periods they may be unable to perform. This risk will need to be priced in each resource's bid in future Forward Capacity Auctions.

Third, the Pay For Performance design is resource neutral. In a well-designed market, two suppliers that provide the same good or service receive the same compensation. Their compensation is not dependent on whether or not they use the same technology to produce it. The Pay For Performance design honors this principle by providing all resources with the same compensation for the same performance, regardless of resource type or technology. This harnesses the full strength of markets and leaves suppliers free to identify and develop the most cost-effective means to improve resource performance.

[44] *See* White Testimony at 42-46.

[45] *See id*. at 48-54.

2. Pay For Performance Is A True Two-Settlement Market Design

As explained in the testimonies Drs. Cramton and White, two-settlement systems are widely used for forward-sold goods, whether in centralized markets or in bilaterally-arranged forward contracts.[46] They are well-understood, and have numerous benefits. Two-settlement systems are conceptually simple, transparent, and provide a clear product definition. They reduce volatility for both suppliers and consumers. And perhaps most importantly, a two settlement design provides strong performance incentives in both the short-run and in the long-run. It motivates suppliers to take any and all cost-effective investments that will enable them to deliver on their future obligations. It also results in strong incentives for only the most reliable, cost-effective resources to take on obligations in the first place.[47]

The three main characteristics of a two-settlement design are a forward price, a forward position, and a settlement for deviations. These are incorporated in the Pay For Performance design as follows.[48]

a. Forward Price

Under Pay For Performance, the forward price is established through the Forward Capacity Auction. This is paid to resources having a Capacity Supply Obligation during the commitment period in the Capacity Base Payment. The Capacity Base Payment is determined by multiplying the Capacity Supply Obligation by the Forward Capacity Auction clearing price (or by the relevant prices for obligations assumed in reconfiguration auctions or bilaterally). Resources that do not take on a Capacity Supply Obligation do not receive Capacity Base Payments. The Capacity Base Payment represents the first of the two settlements in the two-settlement system.

b. Forward Position

A supplier that clears in the Forward Capacity Auction acquires both a physical obligation and a forward financial position in the capacity market. The physical obligation is to offer the MW amount of the Capacity Supply Obligation in both the Day-Ahead Energy Market and the Real-Time Energy Market during the commitment period. These offer requirements are largely the same under Pay For Performance as in the current FCM. The forward financial position under Pay For Performance is the financial obligation to cover the resource's share of the system's total energy and reserve requirements during scarcity conditions.

[46] *See* Cramton Testimony at 6-9; White Testimony at 54-56.

[47] *See id.* at 56-58.

[48] *See id.* 58-60.

c. Settlement For Deviations

When a scarcity condition occurs during the commitment period, a resource with a Capacity Supply Obligation will have its performance measured against its forward financial position, that is, against its share of the system's requirements at the time of the scarcity condition. The resource will receive a Capacity Performance Payment based on the deviation from its share of the system's requirements. If the resource provides more than its share of energy and reserves, it will receive a positive Capacity Performance Payment. If the resource provides less than its share of energy and reserves, it will receive a negative Capacity Performance Payment. The Capacity Performance Payment represents the second of the two settlements in the two-settlement system.

An example will help to illustrate the concepts. Consider a resource that acquires a 300 MW Capacity Supply Obligation in the Forward Capacity Auction. If the total Capacity Supply Obligations of all suppliers is 30,000 MW, then this resource's share of the system's requirements is 1 percent (300 / 30,000). During the commitment period, the resource will be obligated to offer into the energy markets at 300 MW, and it will receive monthly Capacity Base Payments for 300 MW at the auction clearing price.[49]

During any scarcity condition in the commitment period, the resource's financial obligation is a 1 percent share of the system's total energy and reserve requirements at the time. For example, suppose a scarcity condition occurs during an off-peak period when the system's total load is 16,000 MW and the reserve requirement is 2,000 MW. This gives a total system energy and reserve requirement of 18,000 MW. The resource's pro-rata share of the system's requirements during this scarcity condition is its 1 percent share applied to the system's requirements of 18,000 MW. Its pro-rata share is therefore 1 percent × 18,000 MW, or 180 MW. The resource's Capacity Performance Payment for this scarcity condition will be based on its performance relative to 180 MW. Its Capacity Performance Payment will be positive if the resource delivers more than 180 MW of energy and reserves during the scarcity condition, and its Capacity Performance Payment will be negative if it delivers less than 180 MW of energy and reserves during the scarcity condition. In other words, deviations at delivery are determined by comparing the actual performance of the resource, measured by the energy and reserves it supplies, to its share of the system's requirements during the scarcity condition.

It is important to observe that in the Pay For Performance design, a negative Capacity Performance Payment is in no respect a "penalty." In a two-settlement forward market design, the settlement for deviations, whether positive or negative, is simply the second of the two settlements, as agreed to and understood by the parties upon initiating the transaction (in this

[49] *See* White Testimony at 60-65.

case, upon the supplier taking on a Capacity Supply Obligation). If a grain supplier agreed to deliver ten tons of grain in six months, and then only delivered eight, its underperformance would be settled at the spot price. Even if the spot price happens to be higher than the six-month-ago forward price, the grain supplier is not being penalized. The transaction is simply being settled as previously agreed.[50]

In two-settlement forward markets having a liquid spot market, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. For example, the Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions. As there is no spot market for capacity, under Pay For Performance, deviations are settled at an administratively-determined rate specified in the Tariff called the Capacity Performance Payment Rate.

As discussed at length below, the full Capacity Performance Payment Rate as calculated by the ISO is $5,455/MWh. However, the Pay For Performance design includes a phase-in period, such that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh.

The phase-in of the Capacity Performance Payment Rate will smooth the introduction of the Pay For Performance incentives for a number of reasons. First, participants will be able to gain experience under the revised incentives both with the capacity market and with system operations and performance under the new design. The phase-in will also allow the ISO to evaluate the performance of the Pay For Performance approach. Given that there have been concerns expressed that the ultimate Performance Payment Rate might be too high, or that the general approach might be too risky, the ISO can evaluate how people react to the initial low rate and adjust course as needed. This would be based on indicators such as the bids submitted to the IMM and their formulation, changes in system operations, investments in reliability made by resource owners, and entry and exit decisions. For example, if a substantial number of resources have dual fuel at $2,000, and the least reliable resources are leaving the market and being replaced by reliable resources, the ISO can reevaluate the need to increase the Capacity Performance Payment Rate, or the pace at which it is increased. If the risk premiums evident in resource bids appear to be higher than warranted, the ISO can evaluate the cause and adjust course as required.

[50] *See* White Testimony at 53-54.

Finally, it is important to note that resources under Pay For Performance are not asked or expected to physically operate at a MW level equal to their share of the system's requirements. Rather, they are expected to operate as dispatched, regardless of their forward positions. During scarcity conditions, the dispatch software directs resources to produce at a level that maximizes the sum of the energy and reserves they can provide during each interval, subject to the resource's offered capabilities (such as its ramp rate) and the transmission network's capabilities. A supplier's financial incentives under Pay For Performance – which are to maximize its resource's capabilities to provide energy and reserves – are fully aligned with the system's dispatch objectives to make maximum use of those capabilities during scarcity conditions. The share-of-system forward position, then, is not a physical dispatch target. It is a financial arrangement that serves to link payments to performance and thereby create stronger economic incentives for resources to enhance their capabilities to deliver.[51]

3. Resources Without A Capacity Supply Obligation Are Eligible To Receive Capacity Performance Payments

For a resource with a Capacity Supply Obligation, its Capacity Performance Payment is based on the deviation between its actual performance and its share of the system's requirements. For a resource without a Capacity Supply Obligation, its share of the system's requirements is zero. Any energy or reserves that it delivers during scarcity conditions can be viewed as a positive deviation from its share of the system requirements, and should be credited – like all positive deviations – at the same Capacity Performance Payment Rate. This design feature is important because it provides strong performance incentives to all resources, of whatever type, to deliver energy and reserves during scarcity conditions when system reliability is at heightened risk. During scarcity conditions, the pool of potential over-performers that might be able to relieve the shortage should be as broad as possible, and there is no reason to limit that pool to resources having a Capacity Supply Obligation. Also, as noted in the testimony of Mr. LaPlante and Dr. Gheblealivand, resources will be able to price different resource blocks at different prices; thus, while a resource's highest-priced blocks may not take on a Capacity Supply Obligation, they are still eligible to receive Capacity Performance Payments for providing energy or reserves during scarcity conditions.[52]

4. Capacity Performance Payments Are Transfers Among Suppliers

Under the Pay For Performance design, consumers only pay for the Capacity Base Payments, which are fixed at the time of the Forward Capacity Auction. The Capacity Performance Payments are structured as transfers of money from under-performing suppliers to

[51] *See* White Testimony at 64-65.

[52] *See id.* at 67-69.

over-performing suppliers. Hence, the costs to consumers are hedged once the Forward Capacity Auction is complete. They do not bear the financial risk of unexpectedly high Capacity Performance Payments earned by suppliers that perform well during the commitment period. During a scarcity condition, some resources will perform well (above their share of the system's requirements) and others will perform poorly (below their share of the system's requirements). It is the suppliers whose resources perform poorly – below their share of the system's requirements – that bear the risk of covering the positive Capacity Performance Payments to resources that over-perform.[53]

5. Pay For Performance Will Improve Reliability In A Cost-Effective Manner, Unlike The Current FCM Design

One of the most important features of the Pay For Performance design is that it will improve reliability in a cost-effective manner. Cost-effectiveness is simply the ratio of cost to performance. A resource that provides little or no contribution to reliability, even if it offers its capacity in the Forward Capacity Auction at a low price, is not cost-effective. A resource that contributes greatly to reliability, even at a higher price, is likely to be much more cost-effective. In other words, the important measure is not simply the price paid for capacity, but rather the price paid relative to the reliability purchased.[54]

Flaws in the current FCM design result in the clearing of resources that make little or no contribution to reliability. Because capacity payments are not well linked to resource performance, resources that are likely to be poor performers are nonetheless encouraged to participate in the market when they should exit. This leads to numerous problems. Because resources are not selected on the basis of cost effectiveness, consumers are frequently paying an unnecessarily high price for the level of service they obtain during scarcity. Resources with poor performance may clear in the Forward Capacity Auction, displacing competing resources with substantially better performance. The market produces a worse-performing resource mix, which lowers the amount of energy and reserves the ISO can expect to obtain during tight system conditions when reliability is at heightened risk. And, perversely, suppliers find poor performance may be *more* profitable than better performance.

Pay For Performance is designed to address all of these problems. Because payments are strongly linked to performance, suppliers are incented to account for their expected performance when they bid in the Forward Capacity Auction, and each resource's capacity offer price will reflect the resource owner's own estimate of its cost-effectiveness and risk. This will allow the Forward Capacity Auction to select the set of resources that represent the most cost-effective

[53] *See* White Testimony at 66-67, 82-86.

[54] *See id.* at 116-133.

way to meet the system's needs during scarcity conditions. That is, it selects resources with the lowest capacity costs *relative to* the expected amount of energy (and reserves) that the resources will deliver. The less reliable and less cost-effective resources will tend to de-list (not clear) in the Forward Capacity Auction, rather than displace resources with more cost-effective performance.

E. Pay For Performance Is Far Superior To The NEPOOL Alternative

At its December 6, 2013 meeting, the NEPOOL Participants Committee voted in favor of an alternative proposal sponsored by NRG Energy Inc. The NEPOOL proposal includes four components: (1) increasing by $500/MWh the existing administrative price adder in the energy market during scarcity conditions; (2) eliminating the existing Shortage Event mechanism in FCM entirely; (3) adding a "long-term availability incentive," via an annual credit or charge for changes to a resource's five-year EFORp; and (4) adding yet another exemption from performance penalties, in this case when a resource cannot perform because of events that are "out of management control." In short, rather than pursue meaningful and fundamental market-based fixes to the FCM, the NEPOOL proposal will barely increase incentives while effectively eliminating consequences for non-performance. Indeed, the NEPOOL proposal essentially converts the FCM payment stream into a cost-of-service-like payment.

First, if the goal of these changes is to improve incentives for resources to perform during scarcity conditions, NEPOOL's proposed $500/MWh adder is an order of magnitude too small. Dr. White provides extensive testimony explaining how the calculation of the Capacity Performance Payment Rate of $5,455/MWh in the Pay For Performance design was derived, and demonstrates that this level of incentive is necessary during periods of scarcity to meet the region's reliability objectives cost-effectively. NEPOOL's $500/MWh adder, which was not supported by any analysis in the stakeholder process, is simply too small to have any useful impact on resource performance during scarcity conditions.

Second, while the ISO has conceded that the existing Shortage Event mechanism provides only weak incentives for resource performance during scarcity conditions, it is the only feature of the current FCM design that performs such a role. If the Shortage Event mechanism is to be removed, it must be replaced with something that provides even better protections against non-performance. The other elements of the NEPOOL proposal certainly do not fill that gap, and so the FCM would be left even weaker than it is today.

Third, NEPOOL's proposed "long-term availability incentive" cannot succeed. As fully explained by Dr. Cramton and Dr. White in their respective testimonies, the product that must be purchased in the capacity market is actual performance – the delivery of energy and reserves –

during scarcity conditions.[55] This is what the revenue stream that is "missing" from the energy market would compensate, and it is what consumers are paying for in the capacity market. As explained above, using availability, instead of performance, for determining capacity payments is ineffective for inducing investments that improve reliability – yet this is what the NEPOOL proposal would do. Using EFORp, which is essentially measuring availability during summer and winter peak hours, does not ensure that performance is measured when it matters most. Instead it measures performance during what are likely to be some high load hours, and lots of hours of moderate load. And it may be that none of these hours experience shortage conditions. If the system has sufficient, well-performing resources during peak conditions, there is no need to measure performance during those hours. And by averaging in many hours when the system is very unlikely to be under stress, it significantly waters down the effect of performance during the most critical hours. What the market must incent is performance during scarcity conditions; the NEPOOL proposal does not do this.

Indeed, use of the five-year average of EFORp as the benchmark by which to measure availability and purportedly incent performance has a significant perverse result which can be demonstrated by a simple example. Assume two resources of the same size whose performance is being measured. The first resource is a historically poor performer that has an EFORp value of 0.5. As long as that resource raises its EFORp, to say 0.6, it will receive an enhanced performance payment. Assume the second resource has been an excellent performer with an EFORp of 0.95, but its EFORp falls to 0.9. That resource will be penalized for "poor performance." It is patently obvious that consumers are getting much better value from the second resource, yet the first resource will be paid more under NEPOOL's proposal.

Fourth, the ISO has explained at length why exemptions are inconsistent with sound market design. Nonetheless, NEPOOL would add a new and potentially very broad exemption to the FCM design for events that are "out of management control." Exemptions break the much-needed link between payments and performance, and while it is true that suppliers may not be able to prevent some force majeure events, it is obvious that consumers cannot manage any such risks. Sound market design places these risks on suppliers regardless of fault. Adding more exemptions, especially ones as broad and vague as the new one proposed by NEPOOL, is moving completely in the wrong direction.

At bottom, rather than ameliorating the significant problems that the ISO has identified, the NEPOOL proposal will further reduce the already low risk of losing capacity revenues for non-performance, essentially creating a cost-of-service payment for all resources, regardless of their performance. While this section only points out the most critical flaws in the NEPOOL proposal and describes how that proposal moves in the wrong direction, it demonstrates that the

[55] *See* Cramton Testimony at 18-19; White Testimony at 15-17, 42-43.

NEPOOL proposal must be rejected. In its answer to NEPOOL's filing, the ISO will fully critique the proposal and explain further why the Commission must reject it.

F. Details Of The Pay For Performance Design And Tariff Revisions[56]

The core Pay For Performance rules are contained in Section III.13.7 of the Tariff, titled "Performance, Payments and Charges in the FCM." As revised, III.13.7 contains three primary topics:

- Capacity Base Payments are detailed in new Section III.13.7.1. The Capacity Base Payments are very similar to the current FCM capacity payment provisions, and so the provisions in new Section III.13.7.1 are largely made up of existing provisions that have been moved and modified.

- Capacity Performance Payments are detailed in Section III.13.7.2., with potential adjustments described in Section III.13.7.3 and Section III.13.7.4. As the Capacity Performance Payments are an entirely new construct, the language in these provisions is new.

- Charges to Market Participants with a Capacity Load Obligation are detailed in Section III.13.7.5. These provisions are largely unchanged from the currently effective Tariff, except for renumbering and minor conforming changes.

The opening paragraph of Section III.13.7 is being revised to reflect these structural changes to Section III.13.7, and to delete language made obsolete by the implementation of Pay For Performance. All of the remaining provisions of Section III.13.7 are discussed in further detail below.

1. Calculation Of Capacity Base Payments

The monthly Capacity Base Payment under Pay For Performance is described in new Section III.13.7.1, which is substantially the same as currently effective Section III.13.7.2 (though revised to reflect new terminology under Pay For Performance). The general monthly payment or charge (based on a resource's Capacity Supply Obligations) is described in new Section III.13.7.1.1, and the potential peak energy rent deduction is described in new Section III.13.7.1.2.

[56] Unless otherwise specified, all of the Tariff revisions described in this section are shown in the ISO's blacklined Tariff sheets effective June 1, 2018, which are being submitted with Part 2 of this filing as Attachment I-2b.

a. Monthly Payments and Charges Reflecting Capacity Supply Obligations

The provisions in new Section III.13.7.1.1 that describe the monthly Capacity Base Payment are almost identical to the provisions for monthly capacity payments to generating capacity resources in currently effective Section III.13.7.2.1.1. These provisions essentially state that there will be a monthly payment or charge based on Capacity Supply Obligations acquired or shed in a Forward Capacity Auction, in a reconfiguration auction, or through a Capacity Supply Obligation Bilateral. These provisions ensure that the various prices associated with each portion of a resource's Capacity Supply Obligation are properly tracked and accounted for. Treatment of resources that elected a multi-year commitment and of new resources that are prevented from becoming commercial due to a planned transmission facility not being in service are also unchanged from the current rules.[57] Furthermore, the defined term "FCA Payment," included in current Section III.13.7.2.1.1, is no longer needed due to the elimination of the availability provisions, so that has been excluded as a defined term from new Section III.13.7.1.1.

As discussed above, a significant advantage of Pay For Performance is that it is resource-neutral. The same payment provisions apply regardless of resource type. This is in sharp contrast to the current FCM rules, which include separate monthly capacity payment provisions for the various resource types.

b. Peak Energy Rents

The Capacity Base Payment may be decreased by Peak Energy Rents, as is the case with monthly capacity payments under the currently effective Tariff. The Peak Energy Rent provisions in currently effective Section III.13.7.2.7.1.1 are being moved to new Section III.13.7.1.2 and modified to conform to the Pay For Performance structure and terminology.

The opening paragraph in new Section III.13.7.1.2 contains minor revisions to the same paragraph in current Section III.13.7.2.7.1.1. First, it is revised slightly to reflect the Capacity Base Payment terminology of Pay For Performance. Second, references to Section III.13.7.1.1.3(h) and III.13.7.1.1.3(i) are updated to reflect the deletion of those Sections under Pay For Performance. Third, a final sentence has been added to the paragraph stating that Self-Supplied FCA Resources shall not be subject to a Peak Energy Rent adjustment on the portion of the resource that is self-supplied. This is not a new sentence, but rather is being moved from current Section III.13.7.2.7.6, which is being deleted because, as discussed above, there will no longer be separate payment provisions based on resource type.

[57] What is a reference to Section III.13.7.1.1.3(i) in the current rules is instead spelled out in revised Section III.13.7.1.1(a) because current Section III.13.7.1.1.3 is being deleted as part of the Pay For Performance changes.

The "Hourly PER" calculation provisions in new Section III.13.7.1.2.1 are identical to the currently effective Section III.13.7.2.7.1.1.1.

The "Monthly PER Application" provisions in new Section III.13.7.1.2.2 are substantively the same as current Section III.13.7.2.7.1.1.2, but the new Pay For Performance design allows for the language in that section to be greatly simplified. Under the current rules, the PER deduction generally is calculated as the product of the Average Monthly PER and the resource's Capacity Supply Obligation (less any self-supplied MW). Using a minimization function, this amount is limited on the high end to something called the "PER cap." And the deduction is limited on the low end to zero by current Section III.13.7.2.7.1.1.2(c). The "PER cap" is conceptually the same as the Capacity Base Payment under Pay For Performance, and current Section III.13.7.2.7.1.1.2(c) (as well as current Section III.13.7.2.7.1.1.2(b)) uses terminology related to availability penalties, which is obsolete under Pay For Performance. All of these provisions are being deleted and replaced with new language based on the Pay For Performance terminology. This new language in new Section III.13.7.1.2.2 is functionally equivalent to the language in current Section III.13.7.2.7.1.1.2 – it calculates the Peak Energy Rent deduction as the Average Monthly PER multiplied by the resource's Capacity Supply Obligation (less any self-supplied MW), and limits the deduction to no more than the Capacity Base Payment and to no less than zero – but is far more simple and clear.

As explained in detail in the testimony of Dr. White, the Peak Energy Rent deduction is *not* being modified to include a resource's Capacity Performance Payments in determining whether the Peak Energy Rent strike price has been exceeded and by how much. To do so would negate the performance incentives that Pay For Performance is designed to provide. The effect would be to increase the Peak Energy Rent deduction as the resource's Capacity Performance Payments increase. If the positive Capacity Performance Payments that were earned by good-performing resources were then removed from the resource's net FCM revenue each month, the incentive disappears. This is not consistent with the design objectives of Pay For Performance.[58]

2. Calculation Of Capacity Performance Payments

How Capacity Performance Payments will be calculated is set forth in detail in new Section III.13.7.2. Generally, during each five-minute interval in which there is a scarcity condition, each resource will receive a separate performance score according to the following formula:

$$\textit{Capacity Performance Score} = \textit{Actual MW} - (\textit{Balancing Ratio} \times \textit{CSO MW})$$

[58] *See* White Testimony at 166-169.

A resource's Capacity Performance Payment for each five-minute interval during a Capacity Scarcity Condition will be its Capacity Performance Score multiplied by the Capacity Performance Payment Rate. Each of these terms is explained in detail below.

a. Definition of Capacity Scarcity Condition

As previously explained, an important design element of Pay For Performance is strongly linking capacity revenue to actual performance during scarcity conditions. The first step in calculating the Capacity Performance Payment, then, is defining the scarcity conditions in which they will apply. For this reason, the first subsection in III.13.7.2 sets out the definition of a new defined term "Capacity Scarcity Condition." Each Capacity Zone, for each five-minute interval, is assessed separately, such that there could be a Capacity Scarcity Condition lasting for only five minutes in a single Capacity Zone. As explained in the testimony of Dr. White, this enables the frequency of Capacity Scarcity Conditions to match the frequency of scarcity pricing in the energy market, allowing performance incentives in both markets to work in harmony and under the appropriate system conditions.[59]

As stated in new Section III.13.7.2.1, a Capacity Scarcity Condition shall exist in a Capacity Zone for any five-minute interval in which the Real-Time Reserve Clearing Price for that entire Capacity Zone is set based on the Reserve Constraint Penalty Factor pricing for: (i) the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement; (ii) the system-wide Ten-Minute Non-Spinning Reserve requirement; or (iii) the local Thirty-Minute Operating Reserve requirement, each as described in Section III.2.7A(c); provided, however, that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing results only because of resource ramping limitations that are not binding on the energy dispatch.

Stated more simply (as explained in the testimony of Dr. White), the ISO has several distinct reserve requirements, and different types of real-time reserves. There are three primary real-time reserve requirements, and a Capacity Scarcity Condition will be based on whether the real-time energy price incorporates a scarcity price adder (indicating the supply of reserves is less than the required level of reserves) for one or more of the following reserve requirements:[60]

(i) The *system minimum 30-minute reserve* requirement, which is satisfied with offline or online generation capability available in thirty minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' thirty-minute operating reserves ("TMOR"), ten minute non-spinning reserves ("TMNSR"), and ten-minute spinning reserves ("TMSR").

[59] *See* White Testimony at 140-146.

[60] *See id.* at 141-143.

(ii) The *system 10-minute reserves* requirement (sometimes called the system's *contingency reserves* requirement), which is satisfied with offline and online generation capability available in ten minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' TMNSR and TMSR.

(iii) The *zonal 30-minute reserve* requirements, for the zones described above. The supply of reserves that helps satisfy this requirement includes the resources within the zone providing TMOR, TMNSR, and TMSR

This list does not include a zonal 10-minute reserve requirement, because the New England system does not have a 10-minute reserve requirement at the zonal level.

However, new Section III.13.7.2.1 also states that a Capacity Scarcity Condition shall not exist if the Reserve Constraint Penalty Factor pricing applies only because of resource ramping limitations that are not binding on the energy dispatch. This is because such resource ramping limitations do not represent a scarcity of energy, but rather a scarcity of the ramping capabilities of the on-line resources. For example, if the system is ramping total energy production up to match rapidly climbing load, the system may have a transitory violation of a reserve requirement that could not be reduced even if the system had one less MW of energy demand. In this case, the real-time Locational Marginal Price for energy does not incorporate the reserve market's scarcity price. That is, the reserve market has an Reserve Constraint Penalty Factor-based price, but there is no scarcity price adder incorporated into the energy price. For this reason, the Capacity Scarcity Condition definition specifically excludes the circumstance in which Reserve Constraint Penalty Factor-based pricing occurs in the reserve market only because of resource ramping limitations that are not binding on the energy dispatch.

b. Calculation of Actual Capacity Provided During a Capacity Scarcity Condition

Again, a central design element of Pay For Performance is strongly linking capacity revenue to actual performance during Capacity Scarcity Conditions. The second step in calculating the Capacity Performance Payment, then, is determining the resource's actual performance, defined as the quantity of energy and reserves actually provided, during each Capacity Scarcity Condition. For this reason, the second subsection in III.13.7.2 sets out the definition of a new defined term "Actual Capacity Provided."

As stated in new Section III.13.7.2.2, for each five-minute interval in which a Capacity Scarcity Condition exists, the ISO shall calculate the Actual Capacity Provided by each resource, whether or not it has a Capacity Supply Obligation, in any Capacity Zone that is subject to the Capacity Scarcity Condition. Actual Capacity Provided is calculated for all resources, whether or

not they have a Capacity Supply Obligation, because all resources are eligible for Capacity Performance Payments, even if they do not have a Capacity Supply Obligation. As explained by Dr. White, this is an important design feature of Pay For Performance because during periods of reserve deficiency, any and all resources that might contribute energy or reserves to relieve the deficiency should face the same strong incentive to do so.[61]

Since some types of resources increase supply, and other types reduce consumption, in order to alleviate a reserve deficiency, the determination of Actual Capacity Provided for each resource depends on the resource type as described below. Because the resource type categories used correspond to resources that have a Capacity Supply Obligation, new Section III.13.7.2.2 states explicitly that for resources not having a Capacity Supply Obligation (including External Transactions), the Actual Capacity Provided shall be calculated using the provision applicable to the resource type. As stated above, a Capacity Supply Obligation is not needed for a resource to be eligible for Capacity Performance Payments.

i. Generating Capacity Resource

As stated in new Section III.13.7.2.2(a), a Generating Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the resource's output during the interval plus the resource's Real-Time Reserve Designation (including any regulation capability available but not used for energy) during the interval; provided, however, that if the resource's output was limited during the Capacity Scarcity Condition as a result of a transmission system limitation, then the resource's Actual Capacity Provided may not be greater than the resource's Desired Dispatch Point during the interval. Where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f) (capacity backed exports), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales.

This provision generally states that the Actual Capacity Provided by a Generating Capacity Resource shall be the quantity of energy and reserves it provides during the relevant interval. The Actual Capacity Provided is limited to the resource's Desired Dispatch Point if the resource's output was limited by a transmission system limitation during the Capacity Scarcity Condition. This limitation is important to encourage resources to follow dispatch instructions rather than seek higher Capacity Performance Payments by over-performing in ways that might damage the transmission system or otherwise jeopardize reliability. As explained by Dr. White, resources are expected to operate as dispatched, regardless of their forward positions. During scarcity conditions, the dispatch software directs resources to produce at a level that maximizes

[61] *See* White Testimony at 67-69.

the sum of the energy and reserves they can provide during each interval, subject to the resource's offered capabilities (such as its ramp rate) and the transmission network's capabilities.

Section III.13.7.2.2(a) also states that where the resource is associated with one or more External Transaction sales submitted in accordance with Section III.1.10.7(f) (capacity backed exports), the resource will have its hourly Actual Capacity Provided reduced by the hourly integrated delivered MW for the External Transaction sale or sales. This circumstance applies to generators within New England that are serving load outside of the New England control area, through associated capacity-backed export external transactions. Because such a generator is not serving load in New England during the Capacity Scarcity Condition, the amount of its export is not credited to the applicable generating unit's Actual Capacity Provided.

ii. Import Capacity Resource

As stated in new Section III.13.7.2.2(b), an Import Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the net energy delivered (but not less than zero) during the interval in which the Capacity Scarcity Condition occurred. Where a single Market Participant owns more than one Import Capacity Resource, then the difference between the total net energy delivered from those resources and the total of the Capacity Supply Obligations of those resources shall be allocated to those resources pro rata. This is because unlike a portfolio of physical generating assets, for example, where the output of each resource is explicitly and unambiguously associated with that resource, energy transactions bringing energy into New England are not explicitly assigned to a participant's Import Capacity Resources. In this case, allocating the energy delivered pro rata obviates the need for a more complicated mechanism for allocating the delivered energy among a Market Participant's multiple resources, and provides a simple and transparent basis for settlement. Explicit assignment of real-time External Transactions to an Import Capacity Resource is not required at external interfaces with enhanced scheduling,[62] and Pay For Performance is not intended to change these enhanced scheduling provisions of the Tariff. In addition, enabling a Market Participant to explicitly assign its Actual Capacity Provided to different Import Capacity Resources it controls could create inappropriate outcomes if one of its Import Capacity Resources with a Capacity Supply Obligation has reached the resource's stop-loss limit.

iii. On-Peak Demand Resource

As stated in new Section III.13.7.2.2(c), an On-Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. The Average Hourly Output applies to an

[62] *See* Tariff Section III.13.6.1.2.3.

On-Peak Demand Resource configured to supply energy to the system, and the Average Hourly Load Reduction applies to an On-Peak Demand Resource that reduces load on the system. In the latter case, the Average Hourly Load Reduction is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply, consistent with existing Tariff provisions.[63]

iv. Seasonal Peak Demand Resource

As stated in new Section III.13.7.2.2(d), a Seasonal Peak Demand Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the resource's Average Hourly Output or Average Hourly Load Reduction multiplied by 1.08. Again, the Average Hourly Output applies to a Seasonal Peak Demand Resource configured to supply energy to the system, and the Average Hourly Load Reduction applies to a Seasonal Peak Demand Resource that reduces load on the system. In the latter case, the Average Hourly Load Reduction is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply.

v. Real-Time Emergency Generation Resource

As stated in new Section III.13.7.2.2(e), a Real-Time Emergency Generation Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be either: (i) the sum of the electrical energy output of all of the Real-Time Emergency Generation Assets associated with the Real-Time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Scarcity Condition occurred; or (ii) the sum of the baseline electrical energy consumption minus the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO during the interval in which the Capacity Scarcity Condition occurred; and shall be multiplied by 1.08. Condition (i) applies to a Real-Time Emergency Generation Resource configured to supply energy to the system, and condition (ii) applies to a Real-Time Emergency Generation Resource that reduces load on the system. In the latter case, the amount is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply.

vi. Demand Response Capacity Resource

As stated in new Section III.13.7.2.2(f), a Demand Response Capacity Resource's Actual Capacity Provided during a Capacity Scarcity Condition shall be the sum of the Real-Time demand reduction for each Demand Response Asset (in accordance with Section 7.1 of

[63] The 1.08 multiplier is consistent with existing Tariff provisions, *see e.g.* current Section III.13.7.1.5.1.

Appendix E2 to Market Rule 1) associated with the Demand Response Capacity Resource multiplied by 1.08, plus the sum of the Net Supply from each Net Supply Generator Asset associated with the Demand Response Capacity Resource, plus the resource's Real-Time Reserve Designation. For purposes of these calculations, when the output of a Real-Time Emergency Generation Asset exceeds the Demand Response Baseline (adjusted pursuant to Section III.8B.5) of a Demand Response Asset located at the same Retail Delivery Point and Net Supply is produced, any Net Supply of a Net Supply Generator Asset located at the same Retail Delivery Point shall be reduced by the difference between the Real-Time Emergency Generation Asset's output and the adjusted Demand Response Baseline of the Demand Response Asset. A Demand Response Capacity Resource may include both assets that supply energy to the system and that reduce load on the system. In the latter case, the amount is multiplied by 1.08 to account for transmission and distribution losses that are avoided because the resource is reducing load rather than increasing supply. The additional clarification regarding Net Supply is required to avoid double counting where both a Real-Time Emergency Generation Resource and a Net Supply Generator Asset are located at the same Retail Delivery Point.

c. Calculation Of The Capacity Balancing Ratio

The third step in calculating the Capacity Performance Payment is determining the Capacity Balancing Ratio that applies for the Capacity Scarcity Condition. As explained by Dr. White, the Capacity Balancing Ratio is used to determine a resource's share of the system's energy and reserve requirements during a Capacity Scarcity Condition. Conceptually, the calculation of the Capacity Balancing Ratio is simple. As stated in new Section III.13.7.2.3, for each five-minute interval in which a Capacity Scarcity Condition exits, the ISO shall calculate a Capacity Balancing Ratio using the following formula:

(Load + Reserve Requirement) / Total Capacity Supply Obligation

The values used for this calculation, however, will vary depending on the type of reserve deficiency and whether it occurs system-wide or only in a single Capacity Zone, as follows:

i. RCPF Pricing Due To A Violation of System-Wide Thirty-Minute Operating Reserve Requirement

If the Capacity Scarcity Condition is a result of a violation of the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

- Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval. Load excludes reserve designations so as to avoid double counting – the reserve requirement is included in the numerator separately.

- Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval. The sum of these three values is the minimum Thirty-Minute Operating Reserve Requirement.

- Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

ii. RCPF Pricing Due To A Violation of System-Wide Ten-Minute Non-Spinning Reserve Requirement

If the Capacity Scarcity Condition is a result of a violation of the system-wide Ten-Minute Non-Spinning Reserve requirement such that the associated system-wide Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

- Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the New England Control Area during the interval.

- Reserve Requirement = the Ten-Minute Spinning Reserve requirement during the interval plus the Ten-Minute Non-Spinning Reserve requirement during the interval. The sum of these two values is the system-wide ten-minute reserve requirement.

- Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the New England Control Area during the interval.

iii. RCPF Pricing Due To A Violation of Local Thirty-Minute Operating Reserves Requirement

If the Capacity Scarcity Condition is a result of a violation of the local Thirty-Minute Operating Reserves requirement such that the associated Reserve Constraint Penalty Factor pricing applies, then the terms used in the formula above shall be calculated as follows:

- Load = the total amount of Actual Capacity Provided (excluding reserve designations) from all resources in the Capacity Zone during the interval plus the net amount of energy

imported into the Capacity Zone from outside the New England Control Area during the interval (but not less than zero).

- Reserve Requirement = the local Thirty-Minute Operating Reserve requirement minus any reserve support coming into the Capacity Zone over the internal transmission interface. Reserve support coming into the Capacity Zone is subtracted because resources inside the Capacity Zone are not needed to meet this portion of the reserve requirement.

- Total Capacity Supply Obligation = the total amount of Capacity Supply Obligations in the Capacity Zone during the interval.

iv. Simultaneous Violations

The Capacity Balancing Ratio provisions also include rules to determine which values should be used in the Capacity Balancing Ratio formula if a Capacity Zone is simultaneously subject to more than one type of reserve deficiency.[64]

Specifically, in any Capacity Zone subject to both Reserve Constraint Penalty Factor pricing associated with the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement and Reserve Constraint Penalty Factor pricing associated with the system-wide Ten-Minute Non-Spinning Reserve requirement, but not to Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(a) (in particular, the Reserve Requirement is the sum of the Ten-Minute Spinning Reserve requirement plus the Ten-Minute Non-Spinning Reserve requirement plus the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement during the interval). This rule is used because the value of the Reserve Requirement in the Capacity Balancing Ratio reflects the required amounts of each type of reserves that can help alleviate the Capacity Scarcity Conditions. If the system dispatch software activates RCPF pricing for the minimum Thirty-Minute Operating Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserve requirement, then Ten-Minute Spinning Reserves, Ten-Minute Non-Spinning Reserves, and Thirty-Minute Operating Reserves all contribute toward meeting the violated requirement.

And in any Capacity Zone subject to both Reserve Constraint Penalty Factor pricing associated with the local Thirty-Minute Operating Reserves requirement and either subject to Reserve Constraint Penalty Factor pricing associated with the minimum Thirty-Minute Operating

[64] *See* White Testimony at 158.

Reserve requirement sub-category of the system-wide Thirty-Minute Operating Reserves requirement or subject to Reserve Constraint Penalty Factor pricing associated with the system-wide Ten-Minute Non-Spinning Reserve requirement, then for resources in that Capacity Zone the Capacity Balancing Ratio shall be calculated as described in Section III.13.7.2.3(c) (using values applicable to a violation of the local Thirty-Minute Operating Reserves requirement). This rule ensures that a resource located in a Capacity Zone experiencing a zonal reserve requirement violation will have its Capacity Performance Score evaluated relative to its share of the Capacity Zone's energy and reserve requirements. A resource in the rest-of-system has its Capacity Performance Score evaluated relative to its share of the system's requirements (which, in this situation, are also experiencing a violation at the time).

d. Calculation Of The Capacity Performance Score

The fourth step in calculating the Capacity Performance Payment is calculating the resource's Capacity Performance Score for the Capacity Scarcity Condition. As stated in new Section III.13.7.2.4, each resource, whether or not it has a Capacity Supply Obligation, will be assigned a Capacity Performance Score for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Score for the interval shall equal the resource's Actual Capacity Provided during the interval minus the product of the resource's Capacity Supply Obligation and the applicable Capacity Balancing Ratio. The resulting Capacity Performance Score may be positive or negative. This calculation was stated previously as follows:

$$\textit{Capacity Performance Score} = \textit{Actual MW} - \textit{(Balancing Ratio} \times \textit{CSO MW)}$$

Because the values for each of these terms have been calculated in previous steps, it is now possible to calculate the resource's Capacity Performance Score for the Capacity Scarcity Condition.

As explained by Dr. White, the Capacity Performance Score is simply the MW amount by which a resource over-performs or under-performs relative to its share of the system's financial performance obligation at the time of a scarcity condition. The resource's share of the system's requirements is captured in the expression *(Balancing Ratio × CSO MW).* If the Capacity Balancing Ratio is 0.75 and the resource's Capacity Supply Obligation is 100 MW, then that resource's share of the system's requirements during the five-minute Capacity Scarcity Condition interval would be 75 MW. If the resource's Actual Capacity Provided during that interval is greater than 75 MW, then its Capacity Performance Score will be positive. If its Actual Capacity Provided during the interval is less than 75 MW, then its Capacity Performance Score will be negative.[65]

[65] *See* White Testimony at 71-76.

e. The Capacity Performance Payment Rate

Because a resource's Capacity Performance Payment for the five-minute Capacity Scarcity Condition interval is its Capacity Performance Score for that interval multiplied by the Capacity Performance Payment Rate, the fifth step in the process of calculating the Capacity Performance Payment is establishing the applicable Capacity Performance Payment Rate. Under Pay For Performance, this value is set forth in the Tariff.

As stated in new Section III.13.7.2.5, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh. The ISO shall review the Capacity Performance Payment Rate in the stakeholder process as needed and shall file with the Commission a new Capacity Performance Payment Rate if and as appropriate.

i. Derivation Of The $5,455 Per MWh Full Capacity Performance Payment Rate

As explained in the testimony of Dr. White, Pay For Performance is a two-settlement design, with a forward price and a price at which deviations are settled. Under Pay For Performance, the forward price is the Forward Capacity Auction clearing price. When there is a liquid spot market for the forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. In forward-sold goods markets that do not have liquid spot markets at the time of delivery, the settlement price for deviations is stipulated in advance in the forward contract terms. As there is no spot market for capacity, under Pay For Performance, deviations are settled at an administratively-determined rate specified in the Tariff – the Capacity Performance Payment Rate.[66]

The Capacity Performance Payment Rate plays an important role in affecting suppliers' performance and investment incentives. As Dr. White explains, the Capacity Performance Payment Rate serves as a scarcity price 'premium,' in addition to the real-time energy and reserve prices, during periods of scarce supply on the system. More importantly, the Capacity Performance Payment Rate affects resources' longer-term investment incentives. Over time, resources that perform well during scarcity conditions accrue positive performance payments and greater net FCM revenue. Resources that perform poorly (or not at all) during scarcity conditions

[66] *See* White Testimony at 86-111.

earn comparatively less net FCM revenue. Through this mechanism, Pay For Performance creates financial incentives for the system to evolve toward a resource mix that performs well when the power grid experiences operating reserve deficiencies and faces heightened risk to reliability.[67]

In his testimony, Dr. White provides a detailed explanation of how the full Capacity Performance Payment Rate of $5,455 per MWh is calculated. He begins with two specific economic principles that guide the derivation of the Capacity Performance Payment Rate. First, the Capacity Performance Payment Rate must be set at a level such that a new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement. Second, a resource that expects to have zero performance (that is, it expects to supply zero energy and reserves) during all expected scarcity conditions over the course of the commitment period should expect zero net capacity revenue (this is referred to as the "zero revenue for zero performance" principle). Dr. White provides a detailed discussion of how these principles are translated into formulas that, when combined, yield a simple result for the Capacity Performance Payment Rate:[68]

$$PPR \geq \frac{Net\ CONE + RF_{new}}{Scarcity\ Hours_{new} \times Actual_{new}}$$

As Dr. White explains, the Capacity Performance Payment Rate spreads the total capacity revenue that a new entrant requires over its expected production (of energy and reserves) during scarcity conditions. The sum in the numerator of the formula ($Net\ CONE + RF_{new}$) is the new entrant's total cost, including a risk premium (if any), that it must expect to recover from the capacity market in order to be willing to enter. The amount in the denominator ($Scarcity\ Hours_{new} \times Actual_{new}$) is the new entrant's expected total annual performance during scarcity conditions. Performance, in this context, is measured in MWh delivered in the form of energy or reserves, per Capacity Supply Obligation MW, during scarcity conditions. In this way, a new capacity resource earns its capacity revenue by performing during scarcity conditions.[69]

Similarly, an existing capacity resource – one that clears in the auction, whether or not new entry sets price – earns greater net FCM revenue to the extent that it delivers more energy and reserves during scarcity conditions. The resources that clear have positive expected profit in the capacity market (with the possible exception of the marginal resource that sets the capacity clearing price, which may have zero profit).

[67] *See* White Testimony at 87-88.

[68] *See id.* at 88-102.

[69] *See id.* at 101.

Dr. White describes in detail the values used as inputs into the formula and how they were selected, and demonstrates that they lead to a result of $5,455 per MWh. He concludes by noting that while values above $5,455 per MWh would satisfy the inequality expressed in the formula, the Capacity Performance Payment Rate is being set to the lowest value that meets the requirement.[70]

ii. Phase-In Of The Capacity Performance Payment Rate

As indicated above, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh.

The phase-in is being included because Pay For Performance represents a major shift in the Forward Capacity Market design that will significantly impact the capacity revenue streams for some suppliers and impact costs to consumers. It is reasonable to smooth the transition to the new paradigm, and phasing in the Capacity Performance Payment Rate will help to accomplish that. The lower initial value will tend to reduce the financial risk and uncertainties that capacity sellers face under the Pay For Performance design while participants gain experience with the design prior to the full Capacity Performance Payment Rate becoming effective.

During the phase-in period, market participants will acquire greater information and experience about the frequency, timing, and duration of scarcity conditions on the system. They will also acquire years of additional experience with how their individual resources perform during these conditions. This additional information will help suppliers better gauge the risks and rewards they face under the new design, provide additional time for new bilateral arrangements to develop in the marketplace that can help manage and spread risk, and enable the region to better assess the likely impacts of incremental changes in the Capacity Performance Payment Rate on Forward Capacity Auction prices prior to reaching the full Capacity Performance Payment Rate.[71]

f. Calculation Of The Capacity Performance Payment

Finally, as a sixth step, the resource's Capacity Performance Payment for the five-minute Capacity Scarcity Condition interval can be calculated. As stated in new Section III.13.7.2.6, for

[70] *See* White Testimony at 105-111.

[71] *See id.* at 111-116.

each resource, whether or not it has a Capacity Supply Obligation, the ISO shall calculate a Capacity Performance Payment for each five-minute interval in which a Capacity Scarcity Condition exists in the Capacity Zone in which the resource is located. A resource's Capacity Performance Payment for an interval shall equal the resource's Capacity Performance Score for the interval multiplied by the Capacity Performance Payment Rate. Because the Capacity Performance Score may be positive or negative, the resulting Capacity Performance Payment for an interval also may be positive or negative. The Capacity Performance Payment can therefore be either positive (for resources that perform well) or negative (for resources that perform poorly).

g. Monthly Capacity Payment And Capacity Stop-Loss Mechanism

As stated in new Section III.13.7.3, a resource's Monthly Capacity Payment for an Obligation Month shall be the sum of the resource's Capacity Base Payment for the Obligation Month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the Obligation Month. Again, because the total of a resource's Capacity Performance Payments may be positive or negative, its Monthly Capacity Payment may be positive or negative. Furthermore, the Monthly Capacity Payment may be subject to the monthly or annual stop-loss provisions described in new Sections III.13.7.3.1 and III.13.7.3.2, respectively.

The stop-loss provisions essentially limit a supplier's downside exposure in the FCM under Pay For Performance. Although a supplier's net FCM revenue can be negative (which, as described above, is an important incentive component of Pay For Performance), the stop-loss provisions ensure that a capacity supplier does not face unlimited losses for non-performance. The stop-loss mechanisms are designed to provide this protection with minimal distortion to the Pay For Performance incentives and in a manner that is relatively simple and transparent.[72]

As Dr. White explains, the stop-loss mechanism is effectively a mutual insurance system among all resources with a Capacity Supply Obligation. Each capacity supplier receives insurance against the possibility of a large negative Capacity Performance Payment – that is, in excess of the stop-loss limit – in the event that its capacity resource performs poorly in a month with many scarcity hours. This insurance is paid for out of the net surplus that accrues during scarcity conditions.[73]

As described above, the Pay For Performance design results in a net surplus each time scarcity conditions occur. This is because the total amount of resource under-performance (in

[72] *See* White Testimony at 172-176.

[73] *See id*. at 176-184.

MW) exceeds the total amount of resource over-performance (in MW) during any scarcity condition (if this were not the case, there would have been no scarcity condition). Because the under-performance and over-performance are settled at the same price (the Capacity Performance Payment Rate), for each scarcity condition, slightly more will be collected from under-performers than is distributed to over-performers.

As part of the stop-loss mechanism design, that net surplus will be allocated among the pool of capacity suppliers. However, if there is a capacity resource with sufficiently poor performance that its negative Capacity Performance Payment reaches the stop-loss limit – a threshold specified in the Tariff – its negative payment will be capped at the limit, and the net surplus that remains to be shared among all other capacity suppliers will decrease. Hence, if one or more capacity resources reaches the stop-loss limit, other capacity suppliers will receive reduced net FCM payments.

It is even possible in the design that if there are a large number of capacity suppliers that perform very poorly in a month with many scarcity hours, that application of the stop-loss limit could produce a negative net surplus (that is, a net deficiency). In this case, each capacity supplier that does not reach the stop-loss limit will still be allocated a pro-rata share of the negative net surplus. Dr. White's testimony includes several examples demonstrating how the stop-loss mechanism will work in various circumstances.[74]

i. Monthly Stop-Loss

As stated in new Section III.13.7.3.1, if the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

This means that in any month, the most that can be subtracted from a resource's Capacity Base Payment is the Forward Capacity Auction Starting Price multiplied by the resource's Capacity Supply Obligation. This is the monthly stop-loss limit. This specific limit was chosen for several reasons. It is simple and transparent; it can be calculated prior to the Forward Capacity Auction and incorporated into the resource's valuation of a Capacity Supply Obligation. It is high enough that it is unlikely to be reached frequently, and so it will only minimally affect the Pay For Performance incentive structure.[75]

[74] *See* White Testimony at 176-184.

[75] *See id.* at 184-199.

Furthermore, the monthly stop-loss limit is consistent with existing Tariff provisions. Pursuant to existing Section III.13.4.2.1.3(b), if a capacity resource suffers a significant decrease in expected performance before the third annual reconfiguration auction (held approximately four months before the capacity commitment period begins), the ISO would submit a bid on behalf of the capacity resource in that reconfiguration auction for its capacity reduction at the Forward Capacity Auction Starting Price. As Dr. White explains, that provision can be used to calculate a limit to a resource's liability under these existing Tariff provisions. The monthly stop-loss limit was specifically calculated to harmonize with the existing liability limit in the existing significant decrease provisions. If it were set lower, it could undermine the existing incentives by decreasing the financial consequences of failing to either perform or to cover the obligation bilaterally or through a reconfiguration auction.[76]

A resource that reaches the monthly stop-loss limit early in the month can, with strong performance in scarcity conditions that occur subsequently during the same month, finish the month with a net financial position better than the monthly stop-loss limit. This design element helps to reduce the frequency with which resources may reach the stop-loss limit and provides a resource with a continuing incentive to perform even in the event that its losses have reached the monthly stop-loss limit.[77]

It is worth noting that new Section III.13.7.3.1 specifically excludes any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval from the resource's net Capacity Performance Payments for purposes of applying the monthly stop-loss limit. If a resource's performance exceeds its Capacity Supply Obligation, the performance above its obligation is not incorporated in the monthly stop-loss calculation. It is credited in a resource's monthly Capacity Performance Payment, but is excluded from the stop-loss calculations. This treatment of the non-obligated MW of a resource with a Capacity Supply Obligation provides comparability to the non-obligated MW of a resource without a Capacity Supply Obligation. It addition, in some circumstances, it further helps improve a resource's incentives to perform.[78]

Finally, new Section III.13.7.3.1 also includes slightly different treatment for resources that cleared as new resources before the implementation of Pay For Performance and elected to have the relevant Capacity Clearing Price apply for one or more additional Capacity Commitment Periods. This treatment is discussed in subsection iii. below ("Treatment Of Resources Clearing As New Prior To The Ninth Forward Capacity Auction And Electing Multiple-Year Treatment").

[76] *See* White Testimony at 191-195.

[77] *See id.* at 195-196.

[78] *See id*. at 197-199.

ii. Annual Stop-Loss

The second aspect of the stop-loss mechanism is the annual stop-loss limit. While the monthly stop-loss mechanism prevents a large loss resulting from poor performance concentrated in a single month, the annual stop-loss protects against severe losses if a large number of scarcity hours occur during many months in which the capacity resource experiences ongoing poor performance. Generally, under the annual stop-loss mechanism, a capacity resource cannot be worse-off, on an annual basis, than three times its maximum monthly potential net loss.[79]

Specifically, pursuant to new Section III.13.7.3.2, for each Obligation Month, the ISO shall calculate a stop-loss amount equal to:

$$MaxCSO \times [3\ months \times (FCAcp - FCAsp) - (12\ months \times FCAcp)]$$

Where:

MaxCSO = the resource's highest monthly Capacity Supply Obligation in the Capacity Commitment Period to date.

FCAcp = the Capacity Clearing Price for the relevant Forward Capacity Auction.

FCAsp = the Forward Capacity Auction Starting Price for the relevant Forward Capacity Auction.

For each Obligation Month, the ISO shall calculate each resource's cumulative Capacity Performance Payments as the sum of the resource's Capacity Performance Payments for all months in the Capacity Commitment Period to date, with those monthly amounts limited by the monthly stop-loss limit, if applicable, as described in Section III.13.7.3.1.

If the sum of the resource's Capacity Performance Payments (excluding any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval) for all five-minute intervals in the Obligation Month is negative, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the difference between the annual stop-loss amount

[79] *See* White Testimony at 199-210.

calculated pursuant to the formula above and the resource's cumulative Capacity Performance Payments.

Effectively, the annual stop-loss limit is applied to a resource's cumulative Capacity Performance Payments on a rolling basis during the Capacity Commitment Period. That is, each Obligation Month, the ISO will check whether the resource's cumulative year-to-date Capacity Performance Payments (after application of the monthly stop-loss limit each month) exceed the annual stop-loss limit. If this occurs, the Capacity Performance Payment for the current Obligation Month will be limited so that the resource's cumulative negative Capacity Performance Payments do not exceed the annual stop-loss limit. The resource will continue to receive its monthly Capacity Base Payment even if its Capacity Performance Payment is limited by the annual stop-loss limit prior to the end of the commitment period.[80]

Like the monthly stop-loss mechanism, a resource that reaches the annual stop-loss limit early in the commitment period can, with strong performance in scarcity conditions that occur subsequently, finish the year with a net financial position better than the annual stop-loss limit. Again, this design element helps to reduce the frequency with which resources may reach the stop-loss limit and provides a resource with an incentive to perform in the event that its losses have reached the monthly stop-loss limit.[81]

Also like the monthly stop-loss mechanism, the annual stop-loss approach is simple and transparent; it can be calculated prior to the Forward Capacity Auction and incorporated into the resource's valuation of a Capacity Supply Obligation. It is unlikely to be reached frequently, and so it will only minimally affect the Pay For Performance incentive structure.

Finally, the annual stop-loss calculation in Section III.13.7.3.2 also specifically excludes any Capacity Performance Payments associated with Actual Capacity Provided above the resource's Capacity Supply Obligation in any interval from the resource's net Capacity Performance Payments, for the same reasons as described above with respect to the monthly stop-loss limit.

iii. Treatment Of Resources Clearing As New Prior To The Ninth Forward Capacity Auction And Electing Multiple-Year Treatment

As mentioned above, the monthly stop-loss provisions in new Section III.13.7.3.1 include slightly different treatment for resources that cleared as new resources before the implementation

[80] *See* White Testimony at 201-204.

[81] *See id.* at 208-209.

of Pay For Performance and elected to have the relevant Capacity Clearing Price apply for one or more additional Capacity Commitment Periods. Specifically, in the case of a resource subject to a multiple-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5, the amount subtracted from the resource's Capacity Base Payment for the Obligation Month will be limited to an amount equal to the product of the applicable Capacity Clearing Price (indexed for inflation) multiplied by the resource's Capacity Supply Obligation for the Obligation Month.

The reason for this differing treatment is that resources that cleared as new prior to the ninth Forward Capacity Auction and elected multiple-year treatment had no knowledge of the rewards and risks to which they would be subject under Pay For Performance, which will apply to at least some portion of their multiple-year commitment. Such resources did not have the opportunity to price those factors into the Forward Capacity Auction offers (when they cleared as new resources). Hence, the monthly stop-loss for such resources will be based on the applicable Forward Capacity Auction clearing price, instead of the starting price. This stop-loss treatment will limit the risk under Pay For Performance for such resources in a manner consistent with their offers in the Forward Capacity Auction.[82]

Some of these resources, however, may prefer to be subject to the greater rewards and risks offered by full participation in Pay For Performance. For this reason, the Pay For Performance rules include new Section III.13.7.3.3, which allows resources that cleared as new prior to the ninth Forward Capacity Auction and elected multiple-year treatment to opt out of the remaining years of its multiple-year election. This option can be exercised at any point in the resource's remaining multiple-year commitment, but the request much be made in writing to the ISO no later than the Existing Capacity Qualification Deadline for the relevant Forward Capacity Auction. Pursuant to new Section III.13.7.3.3, a decision to so opt out shall be irrevocable, and a resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

h. Allocation Of Deficient Or Excess Capacity Performance Payments

As described above in the discussion of the stop-loss mechanism, the Pay For Performance design results in a net surplus each time scarcity conditions occur because the total amount of resource under-performance (in MW) exceeds the total amount of resource over-performance (in MW) during any scarcity condition. Also as described above, application of the stop-loss mechanism may reduce the amount of this surplus, and could possibly even reduce it so

[82] *See* White Testimony at 210-212.

much that it becomes a deficit. The last major piece of the Capacity Performance Payments calculation addresses what to do with the surplus or deficit.

Pursuant to new Section III.13.7.4, the surplus or deficit remaining after all other relevant settlements have been performed as described above is allocated to resources in proportion to their Capacity Supply Obligations, excluding resources that have reached the stop-loss limit.

Specifically, pursuant to Section III.13.7.4(a), if the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is positive, the deficiency will be charged to resources in proportion to each such resource's Capacity Supply Obligation for the Obligation Month, excluding any resources subject to the stop-loss mechanism described in Section III.13.7.3 for the Obligation Month. If this charge causes a resource to reach the stop-loss limit, then the stop-loss cap will be applied to that resource, and the remaining deficiency will be further allocated to other resources in the same manner as described in Section III.13.7.4(a).

Similarly, pursuant to Section III.13.7.4(b), if the sum of all Capacity Performance Payments to all resources subject to the Capacity Scarcity Condition in the Capacity Zone in an Obligation Month is negative, the excess will be credited to all such resources in proportion to each resource's Capacity Supply Obligation for the Obligation Month. For a resource subject to the stop-loss mechanism for the Obligation Month, any such credit shall be reduced (though not to less than zero) by the amount not charged to the resource as a result of the application of the stop-loss mechanism, and the remaining excess will be further allocated to other resources in the same manner as described in Section III.13.7.4(b).

Pursuant to new Section III.13.7.4, these calculations are performed separately for each type of Capacity Scarcity Condition and for each Capacity Zone. If, for example, Capacity Scarcity Conditions occur in only one Capacity Zone during a particular Obligation Month, then the net surplus is allocated, in proportion to each resource's Capacity Supply Obligation for the Obligation Month, among the capacity resource in that Capacity Zone. Alternatively, if all Capacity Scarcity Conditions apply to all Capacity Zones during a particular Obligation Month, then the net surplus is allocated, in proportion to each resource's Capacity Supply Obligation for the Obligation Month, among all capacity resources in the system. And, last, if there are some Capacity Scarcity Conditions that apply to all Capacity Zones, and other Capacity Scarcity Conditions that apply to only one Capacity Zone, both during the same Obligation Month, then the net surplus is first divided in proportion to the duration of each type of Capacity Scarcity Condition, and then each portion is allocated as in the two previous cases. This process ensures that the resources whose performance contributes to the net surplus due to a Capacity Scarcity Condition in their Capacity Zone are also the resources that primarily bear the benefit (if the net

surplus is positive) or cost (if it is negative) of the insurance that the stop-loss mechanism provides.[83]

As Dr. White explains, allocation of the net surplus or deficit 'in proportion to each resource's Capacity Supply Obligation for the Obligation Month' means in equal dollar amounts per Capacity Supply Obligation MW. Other things equal, if one capacity resource has twice the Capacity Supply Obligation MW of another, the larger of the two resources would receive twice the net allocation of the smaller resource (in dollar terms), but they would each receive the same allocation in dollars per Capacity Supply Obligation MW terms. In other words, the allocation is not a function of individual resources' performance during the month, only their Capacity Supply Obligation MW each month. That is by design, and minimizes distortions to a resource's marginal performance incentives during scarcity conditions.[84]

3. Capacity Performance Bilaterals

The Pay For Performance design includes a simple mechanism for resources to trade their performance bilaterally. Capacity Performance Bilaterals replace the more complicated Supplemental Availability Bilaterals in the current FCM rules. Pursuant to revised Section III.13.5.3, if a resource has a Capacity Performance Score that is greater than zero in a five-minute interval that is subject to a Capacity Scarcity Condition, that resource may transfer all or some of that Capacity Performance Score to another resource for that same five-minute interval so long as both resources were subject to the same Capacity Scarcity Condition.[85] A Capacity Performance Bilateral does not affect in any way either party's Capacity Supply Obligation or the rights and obligations associated therewith. The sole effect of a Capacity Performance Bilateral is to modify the Capacity Performance Scores of the transferring and receiving resources for the Capacity Scarcity Conditions subject to the Capacity Performance Bilateral for purposes of calculating Capacity Performance Payments.[86]

The Lead Market Participant for the transferring resource must submit the bilateral, which must also be confirmed by the Lead Market Participant for the resource receiving the Capacity Performance Score.[87] The submission must identify the transferring and receiving resources, the MW amount of Capacity Performance Score being transferred, and the specific five-minute interval or intervals for which the Capacity Performance Bilateral applies.[88] As Dr.

[83] *See* White Testimony at 212-216.

[84] *See id.* at 215-216.

[85] *See* revised Tariff Section III.13.5.3.1.

[86] *See* Tariff Section III.13.5.3.3 (renumbered from current Tariff Section III.13.5.3.2.4).

[87] *See* Tariff Section III.13.5.3.2.

[88] *See* Tariff Section III.13.5.3.2.2.

White explains, under Pay For Performance there is no need, nor reason, to exclude any resource type from entering into a Capacity Performance Bilateral.[89] For this reason, in revised Section III.13.1.4.1.6, a provision that limits how Real-Time Emergency Generation Resources can participate in such bilaterals is being deleted.[90]

While Capacity Performance Bilaterals may be submitted to the ISO after the relevant Capacity Scarcity Condition occurs,[91] as Dr. White explains, such bilaterals are most valuable to the transacting parties if arranged in advance. Capacity Performance Bilaterals are a highly flexible instrument that enables a resource owner to mitigate the risk of negative Capacity Performance Payment during periods shorter than a month, or on shorter notice than a Capacity Supply Obligation can be shed. The transacting parties may find it valuable to enter into a Capacity Performance Bilateral when they have different expectations about the number of scarcity hours that will occur during a specified period of time, or when one party expects its resource may perform poorly during a specific time period.[92]

4. Market Monitoring And Mitigation Under Pay For Performance[93]

The joint testimony of Mr. LaPlante and Dr. Gheblealivand describes in detail the four main changes to market monitoring and mitigation in the FCM required by the implementation of Pay For Performance. First, under Pay For Performance, only de-list bids from resources associated with Lead Market Participants that are pivotal may be mitigated by the IMM. For this purpose, the revised rules include a new test to determine if a Lead Market Participant is pivotal. Second, the IMM's de-list bid analysis is being revised to remove the risk adjustment from the calculation of net going-forward costs. As a result, the current "net risk-adjusted going forward costs" bid component is being simplified to "net going forward costs," and the risk premium will be included as a separate component of the de-list bid. It is important to the success of Pay For Performance that resources price the risks they perceive from Pay For Performance in their offer. By making the risk premium a separate component, resource owners will be able to fully describe their risk analysis to the IMM. Third, expected Capacity Performance Payments under Pay For Performance are being added as a distinct de-list bid component. Fourth, the threshold below which resources may leave the capacity market without cost review by the IMM (the "Dynamic De-List Bid Threshold") is being increased from $1.00/kW-month to $3.94/kW-

[89] *See* White Testimony at 160-166.

[90] *See* Tariff Section III.13.1.4.1.6 (renumbered from current Tariff Section III.13.1.4.1.3).

[91] *See* Tariff Section III.13.5.3.2.1.

[92] *See* White Testimony at 162-164.

[93] All of the Tariff revisions related to market monitoring and mitigation under Pay For Performance described in this section are shown in the ISO's blacklined Tariff sheets effective June 1, 2014, which are being submitted with this filing as Attachment I-1h, and in the Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand on behalf of the ISO, submitted with this filing as Attachment I-1e (the "LaPlante/Gheblealivand Testimony").

month beginning with the ninth Forward Capacity Auction. Each of these changes, as well as some smaller conforming changes, is discussed below.

a. Under Pay For Performance, The IMM May Only Mitigate De-List Bids From Pivotal Suppliers

Under the current FCM rules, de-list bids submitted at prices equal to or above $1.00/kW-month (the current threshold for submission of Dynamic De-List Bids) are reviewed by the IMM to determine whether the bid is consistent with the resource's net risk-adjusted going forward costs and opportunity costs. Any such bid that is found inconsistent with the resource's net risk-adjusted going forward and opportunity costs is subject to mitigation. Under Pay For Performance, however, the IMM may only mitigate de-list bids at prices above the Dynamic De-List Bid Threshold from resources associated with Lead Market Participants that are found to be pivotal suppliers.[94]

This change is being made because the Forward Capacity Auction can clear without any of a non-pivotal supplier's capacity, and so a non-pivotal supplier cannot exercise unilateral market power and profitably set the price at a non-competitive level. Thus, IMM review of the de-list bids of non-pivotal suppliers is not necessary to assure competitive market outcomes, and it is appropriate to apply mitigation only to the de-list bids of pivotal suppliers whose offers are inconsistent with their going forward costs.[95]

Specifically, revisions to Section III.13.1.2.3.2.1.1.1 and Section III.13.1.2.3.2.1.1.2 state that a de-list bid submitted for a resource that is associated with a Lead Market Participant that is not pivotal will be entered into the Forward Capacity Auction as submitted.[96] For a de-list bid for a resource associated with a Lead Market Participant that is found to be pivotal by the IMM, if the IMM determines that the bid *is* consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as submitted.[97] (Each of these de-list bid components will be described below.)

For a de-list bid for a resource associated with a Lead Market Participant that is found to be pivotal by the IMM, if the IMM determines that the bid is *not* consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance

[94] *See* LaPlante/Gheblealivand Testimony at 19-20.

[95] *See id.* at 20-21.

[96] *See* Tariff Section III.13.1.2.3.2.1.1.1(a) and Section III.13.1.2.3.2.1.1.2(a).

[97] *See* revised Tariff Section III.13.1.2.3.2.1.1.1(b) and revised Tariff Section III.13.1.2.3.2.1.1.2(b).

Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be rejected. In this case, a revised de-list bid based on the IMM-determined values can be accepted by the participant and used in the auction. While the process for a rejected de-list bid varies somewhat depending on whether the bid is a Static De-List Bid, a Permanent De-List Bid, or an Export Bid, these processes are not being changed from the currently effective rules.[98]

The IMM's pivotal supplier determinations will be included in the qualification determination notifications sent to the Lead Market Participants no later than 127 days prior to the Forward Capacity Auction,[99] and in the informational filing submitted to the Commission no later than 90 days prior to the auction.[100]

b. The Pivotal Supplier Test

The new pivotal supplier test that will be applied by the IMM is contained in Section III.13.1.2.3.2.[101] Conceptually, a Lead Market Participant will be considered pivotal if any of the capacity from the existing resources controlled by that Lead Market Participant is needed to satisfy the capacity requirements either system-wide or in an import-constrained Capacity Zone.[102]

A Lead Market Participant is evaluated to determine if it is a pivotal supplier either system-wide or in an import-constrained Capacity Zone. System-wide, a de-list bid will be associated with a pivotal supplier if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of: (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW.[103]

As explained by Mr. LaPlante and Dr. Gheblealivand, the Lead Market Participant's capacity amount is compared to the difference between the total amount of existing capacity and the Installed Capacity Requirement (net of HQICCs) because if the total amount of existing

[98] *See* revised Tariff Section III.13.1.2.3.2.1.1.1(c) and revised Tariff Section III.13.1.2.3.2.1.1.2(c).

[99] *See* revised Tariff Section III.13.1.2.4.

[100] *See* revised Tariff Section III.13.8.1(a)(viii).

[101] A minor conforming change is being made to Tariff Section III.13.2.8.2(b)(iii) to clarify that the pivotal determination in that section, having to do with Insufficient Competition in the Forward Capacity Auction, is distinct from the new Pay For Performance pivotal supplier test described here.

[102] *See* LaPlante/Gheblealivand Testimony at 22.

[103] *See* revised Tariff Section III.13.1.2.3.2.

capacity is greater than the Installed Capacity Requirement (net of HQICCs), then the difference between the two will be a positive value that represents the amount by which the system is "long." In that case, for a supplier to be pivotal, it would have to control an amount of capacity equal to or greater than the excess amount in order for some of its capacity to be needed to satisfy the requirement. Otherwise the resource is not pivotal. If the amount of existing capacity is less than the Installed Capacity Requirement (net of HQICCs), then the difference between the two is the amount by which the system is "short." In that case, all capacity is needed to satisfy the requirement and all suppliers are pivotal.[104]

Witnesses LaPlante and Gheblealivand also explain that the total amount of summer Qualified Capacity of all existing resources used in the pivotal supplier determination will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated. This is because pending Non-Price Retirement Requests and Permanent De-List Bids represent capacity that is highly likely to be removed from the capacity market in the Capacity Commitment Period, and hence is properly excluded from the total amount of capacity in making the pivotal supplier determination. However, this exclusion will not apply to Non-Price Retirement Requests and Permanent De-List Bids submitted by the Lead Market Participant for the resource being evaluated. It is appropriate to include such amounts in the quantity of total existing capacity because its removal is within the control of the Lead Market Participant and exclusion of such amounts could lead to situations where the IMM fails to identify a pivotal supplier with potential market power.[105]

Because the IMM must perform the pivotal supplier test before the Installed Capacity Requirement and related values are approved, the IMM shall use the best available estimates of those values available at that time it does the pivotal supplier analysis, which is in the third quarter of each year. The IMM shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.[106]

Witnesses LaPlante and Gheblealivand also explain that the Lead Market Participant's amount of existing capacity used in the pivotal supplier determination is increased by the greater of 10 percent or 200 MW. This is again because the Installed Capacity Requirement and related values in the pivotal supplier determination will not be not approved by the Commission at the time the pivotal supplier determination must be completed, and so it is reasonable to err on the conservative side by building into the design a small buffer or margin of safety to ensure that de-list bids from Lead Market Participants "near the line" – that could potentially be pivotal once

[104] *See* LaPlante/Gheblealivand Testimony at 23.

[105] *See id.* at 24.

[106] *See* revised Tariff Section III.13.1.2.3.2. *See also* LaPlante/Gheblealivand Testimony at 27-28.

the Installed Capacity Requirement is final – will also be subject to mitigation. This is accomplished by adding a small amount to the Installed Capacity Requirement. If this buffer were not included, and the final Installed Capacity Requirement were higher than previously estimated, then a pivotal supplier might incorrectly appear non-pivotal at the time of the IMM's evaluation.[107]

In an import-constrained Capacity Zone, the pivotal supplier determination will work largely in the same manner as it does system-wide, except that zonal values are used instead of system-wide values for the total amount of existing capacity, the capacity requirement, and the amount of existing capacity controlled by the Lead Market Participant.[108] Also, the buffer to be used in this case is the greater of 10 percent or 100 MW (as opposed to 10 percent or 200 MW, in the system-wide determination). According to Mr. LaPlante and Dr. Gheblealivand, this smaller value reflects the smaller amount of variation in capacity in an import-constrained Capacity Zone than system-wide. The IMM believes that this smaller value is reasonable because each import-constrained Capacity Zone is only a portion of the system and uncertainty about the Local Sourcing Requirement is only a portion of that about the Installed Capacity Requirement.[109]

Mr. LaPlante and Dr. Gheblealivand state that capacity from new resources is excluded from the pivotal supplier determination because including capacity from new resources would not change the pivotal status of the Lead Market Participant of the new resource from pivotal to non-pivotal. But it could change the pivotal status of *other* participants from pivotal to non-pivotal. In other words, some participants that are in fact pivotal might be flagged as non-pivotal if the capacity from new resources is included in the determination of pivotal suppliers.[110]

It is possible that the pivotal supplier test might flag some non-pivotal suppliers as pivotal, Mr. LaPlante and Dr. Gheblealivand concede, but the pivotal supplier test necessarily involves this tradeoff, however, and in its effort to guard against the exercise of market power, the IMM believes there is far less risk to competitive outcomes and market integrity in flagging some non-pivotal suppliers as pivotal than in failing to flag some actually pivotal suppliers. The harm to the owner of the resource in the case of such "false positives" is minimal. Such a resource is not automatically mitigated; it is simply subject to potential mitigation if the submitted de-list bid is inconsistent with its going forward costs. If the de-list bid is consistent with its costs, there is no mitigation. The potential harm from failing to identity an actually pivotal supplier is far more serious. Unmitigated de-list bids from truly pivotal suppliers can

[107] *See* LaPlante/Gheblealivand Testimony at 29.

[108] *See id.* at 30.

[109] *See id.* at 32.

[110] *See id.* at 32-34.

inappropriately set the auction price significantly higher than it would have been where all offers are competitive. For these reasons, the pivotal supplier test is calibrated to identify virtually all potentially pivotal suppliers, even at the (minimal) risk of a false positive.[111]

Finally, Mr. LaPlante and Dr. Gheblealivand explain that the number or size of the resources controlled by a Lead Market Participant is not relevant to the pivotal supplier determination. A Lead Market Participant can be pivotal if only a small amount of its capacity is needed, regardless of the overall number and size of resources controlled. Furthermore, an exception based on the number or size of resources could provide an incentive to spin-off a pivotal generation asset for the purpose of exercising market power. When the amount of existing capacity is smaller than or equal to the applicable capacity requirement, all Lead Market Participants, large or small, and irrespective of the number of assets they control, are pivotal.[112]

c. Changes To The IMM's Review Of De-List Bids

Under the current FCM rules, there are two main components of a de-list bid that are reviewed by the IMM: net risk-adjusted going forward costs, and opportunity costs. The Pay For Performance rule revisions instead break the de-list bid into four distinct components for IMM review: net going-forward costs, expectations about the resource's Capacity Performance Payments, risk premium assumptions, and opportunity costs. Each of these four components will be discussed below, but the notable changes here are: (1) the removal of the risk adjustment from the net going-forward cost calculation and the creation of a distinct risk premium component; and (2) the addition of a new component for expectations about Capacity Performance Payments.[113]

With respect to all of the de-list bid components, Section III.13.1.2.3.2.1.1 is being revised to state that the IMM shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the IMM shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

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[111] *See* LaPlante/Gheblealivand Testimony at 34-35.

[112] *See id.* at 35-36.

[113] *See id.* at 36. A number of Tariff sections are being revised to refer to all four of these de-list bid components, instead of just the two components that exist under the currently effective rules. *See* revised Tariff Sections III.13.1.2.3.2.1, III.13.1.2.3.2.1.1.1, III.13.1.2.3.2.1.1.2, and III.13.8.1(a)(viii).

Mr. LaPlante and Dr. Gheblealivand note that under Pay For Performance, resources will continue to have the ability to submit de-list bids that vary by block for a single resource. Under Pay For Performance, it is important for a resource to be able to submit bids by block, since factors affecting the resource's performance during the Capacity Commitment Period may vary by block. For example, if a resource owner is risk averse, and believes that there is a greater risk that higher output blocks are not able to perform as reliably as lower blocks, it can price this higher risk into the upper blocks. That is economically desirable, as it means the auction is less likely to clear, and the region less likely to rely upon, the blocks of resources that owners believe are less reliable. In addition, the going forward costs of higher blocks may be greater than lower blocks. Allowing de-list bids to be broken into blocks permits this to be reflected in a resource's offer.[114]

i. Net Going Forward Costs

Under Pay For Performance, risks faced by resources are very different that those in the current market. Risks under Pay For Performance vary greatly depending on several factors, including the size of a participant's portfolio, its risk tolerance, and uncertainty about the number of hours with Capacity Scarcity Conditions during the Capacity Commitment Period three years in the future. A risk adjustment is included in the current net risk-adjusted going forward cost formula, but that formula is overly simplistic for use under Pay For Performance since it only reflects unit availability.

Additionally, since each participant's risk tolerance and its method for assessing risk are likely to be different, it is not possible to develop a single formula that would enable all market participants to accurately reflect their risk preferences. Therefore, to permit each participant to thoroughly represent and fully explain their risk premium, under Pay For Performance the risk adjustment is being removed from the net going-forward costs formula, and is being replaced by a separate risk premium component of the bid. As Mr. LaPlante and Dr. Gheblealivand explain, using a formula for calculating the risk premium would force all participants to use the same methodology for calculating their risk premium; this seems an unwarranted intrusion into an area that should be the prerogative of the resource owner.[115]

As a result, the current net risk-adjusted going forward costs formula is being changed from:

[114] *See* LaPlante/Gheblealivand Testimony at 36-37.

[115] *See id.* at 37-38.

$$NRAGFC = \frac{\left[\frac{GFC}{1-EFORd} + RF - (IMR - PER)\right] \times InflationIndex}{Q_{summer} \times 12}$$

To the following net going-forward cost formula:

$$NGFC = \frac{GFC - (IMR - PER) \times InflationIndex}{Q_{summer} \times 12}$$

Except for removal of the risk adjustment terms ("(1-EFORd)" and "RF"), the other variables will remain largely unchanged. These other variables have been in place and calculated successfully by participants for several years.[116] The revisions also include a minor change to the "Inflation Index" term in the net going-forward costs calculation. That term is currently based on the 1-Year Constant Maturity Treasury Rate. After reviewing issues with the current inflation index and studying several historical and forward looking indices, the IMM has determined that the expected 4-year inflation prediction published monthly by the Federal Reserve Bank of Cleveland is the most comprehensive forward looking index for changes in the costs of capacity suppliers.[117] These changes are reflected in Section III.13.1.2.3.2.1.2.[118]

ii. Risk Premium

With the risk adjustment removed from the net going forward cost calculation, the Tariff revisions implementing Pay For Performance include a new Section III.13.1.2.3.2.1.4 that details the separate risk premium component of a de-list bid. That section states that the Lead Market Participant for a resource submitting a de-list bid that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. Such documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for

[116] *See* LaPlante/Gheblealivand Testimony at 39-40.

[117] *See id.* at 40. The data on expected inflation is available at: http://www.clevelandfed.org/research/data/inflation_expectations/.

[118] A minor conforming change is also being made in several sections to change the term "net risk-adjusted going forward costs" to "net going forward costs." *See* revised Tariff Sections III.13.1.2.3.2.1, III.13.1.2.3.2.1.2, and III.13.1.2.4. Also, in current Section III.13.1.2.3.2.1, there is a provision stating that de-list bid costs shall be submitted using spreadsheets and forms provided by the ISO. Because these spreadsheets and forms are specific to net going-forward costs, this provision is being moved to revised Section III.13.1.2.3.2.1.2.

net going forward costs may be included in the risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the FCM is consistent with the participant's corporate risk management practices. The IMM will review the affidavit and the risk analysis, compare it to those submitted by other participants, and ask for additional information if necessary.

Mr. LaPlante and Dr. Gheblealivand explain that the IMM views the risk premium as an essential part of each participant's offer. The future number of scarcity hours, the Capacity Balancing Ratio, and a resource's performance during the commitment period are all uncertain when a resource owner submits a new supply offer or a de-list bid. In making decisions about future investments and expenditures, we expect that resource owners will consider that uncertainty. Therefore, it is necessary for their de-list bids to also include that uncertainty so that the bids accurately reflect the price that resources require to participate in the market and meet the associated obligations.[119]

More technically, the IMM defines the risk premium as the amount of expected profit a participant would be willing to forego in order to avoid some of the "downside" risk of losing money in the capacity market. Participants form their expectations about relevant market variables, calculate their expected profit-maximizing bid, and then add a premium depending on how much of the downside they want to avoid. Adding any risk premium to an expected-profit maximizing bid lowers the probability of clearing in the Forward Capacity Auction by enough that it will reduce the resource's expected profit. However, if the resource still clears in the auction, it may increase the resource's Capacity Base Payment – and therefore lowers its risk of losing money during the Capacity Commitment Period.[120]

Mr. LaPlante and Dr. Gheblealivand state that the IMM will evaluate each de-list bid in two ways. First, for units that are part of a multi-unit portfolio, the IMM will ascertain whether the risk premium requested for each of the units in the portfolio reflects consistent assumptions on key parameters affecting risk across the portfolio, including the expected number of hours of Capacity Scarcity Conditions. This may require the IMM to ask for information from a participant about other resources it owns for which it has not submitted de-list bids to determine if applying the assumption used in the submitted bids to other units would result in going forward costs higher than the Dynamic De-List Bid Threshold. If this occurs, the IMM will

[119] *See* LaPlante/Gheblealivand Testimony at 40-41.

[120] *See id.* at 41.

likely discuss these results with the participant to understand why de-list bids were submitted for the selected units and not others.[121]

The second way in which the IMM will evaluate the risk premium portion of de-list bids is by comparing the risk premia across participants. If all of the risk premia are within the same range, then that would support a finding of a reasonable risk premium consistent with competitive market behavior. Participants with risk premium submittals that are noticeably outside of the range of reasonableness established by all of the risk premia taken together will likely be asked for further explanation. The results of these analyses will be used by the IMM to determine if the risk premium is reasonable and consistent with the resource's net going forward costs.[122]

iii. Expected Capacity Performance Payments

Pursuant to Section III.13.1.2.3.2.1.3 of the revised rules, the Lead Market Participant for a resource submitting a de-list bid shall also provide documentation separately detailing its expected Capacity Performance Payments for the resource. This documentation must include assumptions regarding the Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

The Capacity Performance Payments are being included as a separate component of the de-list bid because the assumptions supporting a resource's estimate of its expected Capacity Performance Payment will enable the IMM to evaluate whether the resource's bid is competitive.[123]

From the IMM's perspective, the significance of a resource's expected Capacity Performance Payments is their importance in determining a competitive bid for the resource. For most resources, a competitive bid will simply be the opportunity cost of taking on a Capacity Supply Obligation. Each resource will have its own estimate of that opportunity cost. This component of the de-list bid will enable the IMM to review the assumptions used by the resource in calculating its opportunity cost. For a minority of resources, however, a bid based simply on the opportunity cost of taking on a Capacity Supply Obligation will not be enough to cover their net going forward costs. The competitive bid for those resources must include an adder to their

[121] *See* LaPlante/Gheblealivand Testimony at 45. Tariff Section III.13.1.2.3.2.1.1 is revised to state explicitly that the IMM may seek information from the Lead Market Participant about other existing or potential new resources in the Lead Market Participant's portfolio.

[122] *See id.* at 45.

[123] *See id.* at 46.

estimate of opportunity costs large enough to assure that they cover all of their going forward costs during the commitment period.[124]

The assumptions used in the calculation of a resource's expected Capacity Performance Payments enable the IMM to determine the resource's opportunity cost of taking on a Capacity Supply Obligation. Under Pay For Performance, a resource that has not taken on a Capacity Supply Obligation will also be paid the Capacity Performance Payment Rate multiplied by the amount of energy and reserves that it provides during a Capacity Shortage Condition.[125]

Resources that do take on a Capacity Supply Obligation are selling forward their pro-rata share of the system's energy and reserve requirements during Capacity Scarcity Conditions. In other words, in exchange for the Capacity Base Payment, they agree to provide their share of the system's requirements during Capacity Shortage Conditions in the commitment period. For a resource to take on this obligation, it will want to receive at least the amount of money it could have received by not taking on a Capacity Supply Obligation – that is, its opportunity cost.[126]

The difference between a resource's Capacity Performance Payment with a Capacity Supply Obligation and without a Capacity Supply Obligation is the Capacity Performance Payment Rate times the expected number of hours of Capacity Scarcity Conditions times the expected Capacity Balancing Ratio. This is the resource's opportunity cost of acquiring a Capacity Supply Obligation, and therefore is the minimum payment that a resource will require to take on a Capacity Supply Obligation. The resource owner's expectations of the number of hours of Capacity Scarcity Conditions and the Capacity Balancing Ratio enable the IMM to evaluate the resource's opportunity cost of taking on a Capacity Supply Obligation.[127]

A resource's expected revenues under Pay For Performance must be considered in evaluating its de-list bid to determine if these revenues are sufficient to cover the resources going-forward costs net of energy revenues. For a resource to take on a Capacity Supply Obligation, it must expect that it will earn enough money through its participation in the FCM to cover its net going forward costs. The going forward cost calculation described above shows whether or not a resource will earn enough revenue from the energy and ancillary services markets to cover its going forward costs. If a resource earns enough revenue from the energy and ancillary services markets to cover its going forward costs, then its competitive bid in the capacity market is simply its opportunity cost, as described above.[128]

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[124] *See* LaPlante/Gheblealivand Testimony at 47.

[125] *See id.* at 48.

[126] *See id*.

[127] *See id.* at 48-49.

[128] *See id.* at 49.

If a resource does not earn enough revenue from the energy and ancillary services markets to cover its going forward costs, then additional calculations must be done to determine whether its competitive bid in the capacity market is simply its opportunity costs or if the bid has to be increased to assure recovery of its net going-forward costs. The first such calculation is to determine whether the resource would earn enough revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) to cover its net going-forward costs. If it does, the resource would not *need* to assume a Capacity Supply Obligation to receive Capacity Base Payments to cover its net going-forward costs and consequently the only cost it incurs in taking on a Capacity Supply Obligation is its opportunity cost. If the first calculation shows that the expected revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) is not enough, then a second calculation has to be done to determine how much additional revenue is needed. This calculation is done by subtracting the Capacity Performance Payments (absent a Capacity Supply Obligation) from the net going-forward costs. This difference has to be added to the resource's opportunity cost to assure that it will be able to cover both its share of the system financial obligation and its net going-forward cost if it receives a Capacity Supply Obligation.[129]

As explained by Mr. LaPlante and Dr. Gheblealivand, the IMM will evaluate the Lead Market Participant's expectations regarding the applicable Capacity Balancing Ratio, the number of Capacity Scarcity Conditions, and the resource's performance during Capacity Scarcity Conditions using information from various sources. For the Capacity Balancing Ratio and the number of hours of Capacity Scarcity Conditions, the IMM will rely on two sources. The first source is the ISO's estimates of these two variables depending on the expected nature of Capacity Scarcity Conditions (whether they are expected in the summer or winter) and the total amount of capacity available in the system. The number of hours with Capacity Scarcity Conditions is inversely related to the amount of excess supply in the system. The second source for reasonable estimates of these variables is the range that is established by other Static De-List Bid and Permanent De-list Bid submissions. The IMM can use other Static and Permanent De-list Bid submissions because (unlike resource-specific performance) the Capacity Balancing Ratio and the number of hours with Capacity Scarcity Conditions affect all resources. We will treat these estimates in the same way as estimates of the risk premium. Participants with submittals that are noticeably outside of the range of reasonableness established by the universe of submissions will likely be asked for additional information. In addition, and similar to evaluation of risk premia, the IMM may ask for information from a participant about resources that belong to that participant that have not submitted de-list bids to determine if applying the assumptions used in the submitted bids, particularly on Capacity Balancing Ratio and the expected number of scarcity conditions, to other resources would warrant submission of Static or Permanent De-List Bids for those other resources. If this occurs, the IMM will likely discuss

[129] *See* LaPlante/Gheblealivand Testimony at 49-50.

these results with the participant to understand why de-list bids were submitted for the selected resources and not others.[130]

For resource performance during reserve deficiencies, the IMM can rely on years of data on existing resources. If a participant believes that its performance may be significantly different than what has been observed in the past, it can explain this in its Static De-List Bid and Permanent De-list Bid submission or in response to IMM inquiries.[131]

iv. Opportunity Costs

Unlike risk premia and expected Capacity Performance Payments, opportunity costs are already a de-list bid component under the current FCM rules. To conform with the revisions described above, however, some minor changes are being made to the opportunity costs provisions.[132] First, the provision is being reworded to clarify that opportunity costs should only include costs not reflected in the net going-forward costs, expected Capacity Performance Payments, or risk premium components of the bid. This is necessary to ensure that costs are appropriately categorized and that there is no double-counting. Second, references to quantifiable risk in the current opportunity cost provisions are being deleted. This is because any risk elements should be instead be included in the new risk premium de-list bid component. Third, the revisions remove redundant procedural language from the opportunity costs provisions.[133]

d. Increasing The Dynamic De-List Bid Threshold

In the current FCM, there are two types de-list bids that enable a resource to leave the capacity market for a single Capacity Commitment Period. Resources that wish to leave the market at prices equal to or above $1.00/kW-month, must submit Static De-List Bids in advance of the Forward Capacity Auction for review by the IMM. If resources wish to leave the market at prices below $1.00/kW-month, they may submit a Dynamic De-List Bids during the Forward Capacity Auction without review by the IMM.[134]

Throughout the currently effective FCM rules, this $1.00/kW-month threshold between the two types of de-list bids is spelled out as "$1.00/kW-month." Whenever the threshold for submission of Dynamic De-List Bids is changed, each of these many instances must be updated

[130] *See* LaPlante/Gheblealivand Testimony 50-51.

[131] *See id.* at 51-52.

[132] The opportunity cost provisions are in Section III.13.1.2.3.2.1.3 of the current FCM rules, but this is being renumbered to Section III.13.1.2.3.2.1.5 in the revised rules.

[133] *See* LaPlante/Gheblealivand Testimony at 52-53.

[134] *See, e.g.*, current Tariff Sections III.13.1.2.3.1.1 and III.13.2.3.2(d).

in the Tariff. For simplification, the revised rules submitted here replace each of those instances with a new defined term, the "Dynamic De-List Bid Threshold." A new Section III.13.1.2.3.1.A is being added to the Tariff to specify the numeric value of the Dynamic De-List Bid Threshold. If that value is changed in the future, it will no longer be necessary to update numerous sections of the Tariff; a single change to the new section will suffice.[135]

As explained by Mr. LaPlante and Dr. Gheblealivand, beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018), the Dynamic De-List Bid Threshold is being raised to $3.94/kW-month. This is because the Pay For Performance design changes the definition of the capacity product and therefore changes the level of a competitive offer in the capacity market for all resources. Ideally, the IMM would set the Dynamic De-List Bid Threshold at the competitive bid of the marginal unit. By doing this, the IMM would only review non-competitive bids that could have material impact on the market outcomes. However since it is obviously not possible to know the marginal unit prior to the auction, the IMM used values representative of fossil steam units to set the Dynamic De-List Bid Threshold because these are the type of existing resources most likely to seek to leave the auction and therefore could be the marginal unit if there is more existing capacity than needed to meet the Installed Capacity Requirement.[136]

Mr. LaPlante and Dr. Gheblealivand explain how the IMM calculated the Dynamic De-List Bid Threshold, using the following formula:

$$b_i = PPR \times Br \times H + \max\{0, GFC_i - PPR \times A_i \times H\}$$

Where:

- *PPR* is the Capacity Performance Payment Rate specified in the Tariff.
- *Br* is the expected Capacity Balancing Ratio.
- *H* is the expected number of hours with Capacity Scarcity Conditions during the commitment period.
- *GFC* is the resource's net going forward cost.
- *A* is the expected average performance of the resource during Capacity Scarcity Conditions during the commitment period.

[135] The new term "Dynamic De-List Bid Threshold" replaces the specific numeric value in the following Tariff Sections: III.13.1.2.3.1.1, III.13.1.2.3.1.2, III.13.1.2.3.1.3, III.13.1.2.3.2.1, III.13.1.2.3.2.1.1.1, III.13.1.2.3.2.1.1.2, III.13.1.2.3.2.1.2, III.13.1.2.3.2.1.5 (formerly Section III.13.1.2.3.2.1.3), III.13.1.8(e), and III.13.2.3.2(d).

[136] *See* LaPlante/Gheblealivand Testimony at 54-55.

Mr. LaPlante and Dr. Gheblealivand provide a detailed explanation of each of the components of this formula and why it is appropriately used in calculating the Dynamic De-List Bid Threshold.[137]

As stated in the revised rules, the Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the IMM will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.[138]

e. Other Conforming Changes

In the current FCM rules, Static De-List Bids and Permanent De-List Bids are each described as a means to "opt out of the capacity market." Under Pay For Performance, however, resources without a Capacity Supply Obligation will nonetheless be eligible for Capacity Performance Payments and so in that sense are not technically "out of the capacity market." For this reason, those provisions are revised to state instead that Static De-List Bids and Permanent De-List Bids "specify a price below which it [the resource] would not accept a Capacity Supply Obligation."[139]

In Section III.13.1.2.4, there is a sentence stating that each accepted de-list bid shall be binding and shall be entered into the Forward Capacity Auction as submitted. Because under certain circumstances, Static De-List bids may be revised after they are submitted (as provided in Section III.13.1.2.3.2.1.1.2), this sentence in Section III.13.1.2.4 is no longer accurate, and hence is being deleted here.

5. Financial Assurance Under Pay For Performance

The testimony Mr. Montalvo describes in detail the revisions to the Financial Assurance Policy ("FAP") needed with the implementation of Pay For Performance.[140] To date, financial assurance related to participation in the FCM has been limited to new resources that are not yet commercial. For a resource that is operating commercially, taking on a Capacity Supply

[137] *See* LaPlante/Gheblealivand Testimony at 55-61.

[138] *See* revised Tariff Section III.13.1.2.3.1.A.

[139] *See* revised Tariff Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2

[140] All of the Tariff revisions related to financial assurance under Pay For Performance described in this section are shown in the ISO's blacklined Tariff sheets effective June 1, 2018, which are being submitted with Part 2 of this filing as Attachment I-2b, and described in the Testimony of Marc D. Montalvo on behalf of the ISO (the "Montalvo Testimony"), submitted with this filing as Attachment I-1f.

Obligation in the FCM currently does not result in any additional financial obligations. Capacity payments during a Capacity Commitment Period under the current FCM design cannot be negative, and hence, for commercial resources, there has been no potential financial obligation to collateralize.[141] As described above, and in the testimony of Dr. White, however, under Pay For Performance, a resource's net capacity payments may be negative.[142] In this way, Pay For Performance introduces the possibility that commercial resources with Capacity Supply Obligations will have net payment obligations (i.e., owe money) to the market. The goal of the FAP is to ensure that there is sufficient cash available to clear the market each day and to cover a participant's settled obligations in the case of default.[143] Hence, the FAP must be revised to account for the possibility of net payment obligations for commercial resources under Pay For Performance.

To collateralize this additional potential obligation, a Market Participant with a Capacity Supply Obligation will be required to add Forward Capacity Market Delivery Financial Assurance ("FCM Delivery FA") to its total FA requirements calculation. As explained by Mr. Montalvo, FCM Delivery FA is designed to address three types of risk: (1) clearing risk, (2) credit risk, and (3) liquidation risk.[144] Clearing risk is the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month, which could result in a cash imbalance that impairs the ability of the ISO to clear all market positions. Credit risk is the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with Capacity Supply Obligations in the current delivery month. Liquidation risk in this context has two components: the risk that losses may continue to accrue against a Capacity Supply Obligation position post default up to the annual stop-loss in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. In addition to addressing these three types of risk, the FCM Delivery FA amount is adjusted to account for the phase-in of the Capacity Performance Payment Rate.

The monthly FCM Delivery FA requirement will be calculated using the following formula:

$$\text{FCM Delivery FA} = \text{MCC} + \text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1)] \times \text{SF} \times \text{DF}$$

Each of these terms, and its role in addressing the three types of risk, is discussed below.

[141] *See* Montalvo Testimony at 2-3.

[142] *See* White Testimony at 77.

[143] *See* Montalvo Testimony at 2-3.

[144] *See id.* at 3.

a. Clearing Risk

The first of the three risks is clearing risk – the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month. To address clearing risk, the first component of the FCM Delivery FA formula is MCC, the "monthly capacity charge." This is simply an amount equal to all negative capacity payments incurred in previous months, but not yet paid.[145]

b. Credit Risk

The second of the three risks is credit risk – the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with CSOs in the current delivery month. This risk is addressed in the portion of the FCM Delivery FA formula that states: DFAMW × PE × max[(ABR – CWAP), 0.1)]. At a high level, the "DFAMW" term represents the MW amount on which a Market Participant must submit FCM Delivery FA; "PE" is the dollar per MW value that will apply in calculating the Market Participant's FCM Delivery FA; and "max[(ABR – CWAP), 0.1]" is a ratio reflecting the performance of the Market Participant's capacity resources.[146] Each of these terms is described in more detail below.

DFAMW, or "delivery financial assurance MW," is, simply, the total MW amount of a Market Participant's resources subject to a Capacity Supply Obligation in the current month. As explained by Mr. Montalvo, this MW amount serves as the basis for the credit risk portion of the FCM Delivery FA calculation. The DFAMW is equal to the sum of the Capacity Supply Obligations of all resources in the Market Participant's portfolio for the current month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount.[147] A resource that has reached the annual stop-loss amount cannot incur any further negative capacity payments in the current month, and so there is no additional amount of FA associated with that resource that is needed to protect against default, and so such resources are excluded from the calculation.[148] In no case will DFAMW be less than zero.[149]

PE, or "potential exposure," is the dollar per MW value that will apply in calculating the Market Participant's FCM Delivery FA. As Mr. Montalvo explains, PE is a monthly value calculated for the Market Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply

[145] *See* Montalvo Testimony at 4-5.

[146] *See id.* at 5-6.

[147] *See id.* at 6.

[148] *See id.* at 6-7.

[149] *See id*. at 6, 7.

Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount.[150] The difference between the Forward Capacity Starting Price and the capacity price is used because, as a general matter, this is equivalent to how the stop-loss amounts are calculated under Pay For Performance, and so represent the amount per MW that the Market Participant might be required to pay if its resources fail to perform.[151] Mr. Montalvo's testimony contains further details regarding the calculation of PE.[152]

The term Max[(ABR – CWAP), 0.1] is a ratio reflecting the performance of the Market Participant's capacity resources. As described above, under Pay For Performance, a resource is not held to the standard of providing the full amount of its Capacity Supply Obligation in all cases. Rather, the amount of capacity that a resource provides during a Capacity Scarcity Condition is measured against the ratio of the total amount of load plus the reserve requirement, divided by the total amount of Capacity Supply Obligations – the Capacity Balancing Ratio.[153]

As Mr. Montalvo explains, because capacity payments are linked to the Capacity Balancing Ratio, FCM Delivery FA must be as well. Requiring a Market Participant to provide FA based on the full amount of its Capacity Supply Obligations would over-state the amount needed to protect against default because negative capacity payments will only be tied to the full Capacity Supply Obligation amount when the Capacity Balancing Ratio is 1.0 – that is, when the system is so stressed that the amount of load plus reserves is equal to the total amount of Capacity Supply Obligations. The term "max[(ABR – CWAP), 0.1]" is the minimum percentage of the calculated potential exposure (PE) that must be posted as financial assurance given assumptions regarding the average system-wide Capacity Balancing Ratio and on the performance of the Market Participant's resources.[154]

The term "ABR," or "average balancing ratio," is the seasonally adjusted, duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period.[155]

The term "CWAP," or "capacity weighted average performance," is the capacity weighted average performance of the Market Participant's portfolio. Generally, the better a

[150] *See* Montalvo Testimony at 7.

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

[152] *See id.* at 8-9.

[153] *See id*. at 9.

[154] *See id*. at 9-10.

[155] *See id*. at 10-12.

Market Participant's resources have performed, the higher its CWAP value will be, and the lower the value (ABR – CWAP) becomes. The worse a Market Participant's resources have performed, the lower its CWAP value will be, and the higher the value (ABR – CWAP) becomes.[156]

For a resource with a CWAP value that approaches or exceeds ABR, the value (ABR – CWAP) will become very low, or possibly even negative. If this value reached zero, the credit risk portion of the FCM Delivery FA would also become zero. As Mr. Montalvo explains, although this would occur because the Market Participant's resources were performing well, even those portfolios with a CWAP value higher than the ABR are not completely without risk. The ABR and the CWAP are based on historical data, and if future performance is worse, holding some FA associated with credit risk is a reasonable and prudent protection. For this reason, the maximization function included in the term "max[(ABR – CWAP), 0.1]" ensures that the value of that term will not be below 0.10, and hence, at least ten percent of the potential exposure amount will be included in the FCM Delivery FA amount.[157]

The testimony of Mr. Montalvo includes numerous additional details about the calculation of max[(ABR – CWAP), 0.1].[158]

c. Liquidation Risk

The third of the three risks is liquidation risk – the risk that losses may continue to accrue against a CSO position post default up to the annual stop-loss limit in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. Liquidation risk is addressed in the "SF," or "scaling factor," term included in the FCM Delivery FA formula. The scaling factor is a month-specific multiplier, as follows:[159]

- June: 2.000;
- December and July: 1.732;
- January and August: 1.414;
- all other months: 1.000.

As Mr. Montalvo explains, the risk that losses may continue to accrue against a Capacity Supply Obligation position post default (up to the annual stop-loss limit) before a market participant is able to close the position is not uniform across all months of the Capacity

[156] *See* Montalvo Testimony at 12-15.

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

[158] *See id.* at 12-18.

[159] *See id.* at 18.

Commitment Period. The likelihood of a severe scarcity event is different each month of the year. The risk of scarcity is highest in the summer months (June – September), followed by the winter months (December – February) and lowest in the shoulder months (the other months). Furthermore, given that in the summer and winter, there are consecutive high-risk months in a row, should a resource default early in the summer season, for example, there is the risk that it will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions.[160]

In large measure this risk exists because a defaulted Capacity Supply Obligation position is not terminated from the market. Rather, the Market Participant must close the position through a bilateral contract or continue to be exposed to charges up to the annual stop-loss limit. While the maximum possible exposure is the annual stop-loss limit, the probability that a resource will hit the monthly stop-loss limit three months in a row (the annual stop-loss limit equals three times the monthly stop-loss limit) is low. Thus, requiring Market Participants to post financial assurance up to the annual stop-loss limit would unnecessarily over-collateralize the market. Nonetheless, additional financial assurance is required to address the risk that a defaulted position will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions in the summer and winter seasons when Capacity Scarcity Conditions are likely to be more frequent. For this purpose, the ISO has assumed that the potential exposure in any remaining months of a season are normally distributed and that the exposure to incremental losses declines with the square-root of the number of months remaining in the season. Thus, during high risk months (summer and winter), the scaling factor (SF) is calculated as the square root of the number of summer or winter months remaining in the seasonal period. For example, the SF is two (square root of four) in June, and becomes one (square root of one) in September. During all the shoulder months, the scaling factor is one. This is explained further in Mr. Montalvo's testimony.[161]

d. Adjustment To FCM Delivery FA To Account For The Phasing In Of The Capacity Performance Payment Rate

As described above, under the Pay For Performance design, the Capacity Performance Payment Rate is being phased in. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3,500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5,455/MWh.

[160] *See* Montalvo Testimony at 19.

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

As Mr. Montalvo explains, an adjustment to FCM Delivery FA is warranted to reflect the reduced exposure to losses during the years in which the Capacity Performance Payment Rate is being phased in. For this purpose, the FCM Delivery FA calculation includes a discount factor, "DF," which is a multiplier to the credit risk portion of the FCM Delivery FA amount. The discount factor is based on the likelihood of a single resource portfolio reaching its monthly stop-loss under different Capacity Performance Payment Rates. For a single resource portfolio, a lower Capacity Performance Payment Rate requires more hours of Capacity Scarcity Conditions to reach the monthly stop-loss amount.[162]

As Mr. Montalvo further explains, based on the data analyzed by the ISO, for a Capacity Performance Payment Rate of $2,000/MWh the PE is 60 to 90 percent of the value at a Capacity Performance Payment Rate of $5,455/MWh. However, given the uncertainly in the data and the imprecision of the calculation, the ISO has opted to split the difference and set the PE when the Capacity Performance Payment Rate is $2,000/MWh at 75 percent of its full value. Thus, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the discount factor shall equal 0.75, and thereafter, it equals 1.00. Mr. Montalvo explains the rationale and derivation of the discount factor further in his testimony.[163]

6. Other Conforming Rule Changes

a. Import Capacity Resource Offer Obligations

Pursuant to the currently effective FCM rules, an Import Capacity Resource with a Capacity Supply Obligation must offer energy associated with the resource into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions priced at or below an administratively-determined daily offer price threshold. Pay For Performance makes this requirement unnecessary. Accordingly, this administrative requirement is being removed from the Tariff. Specifically, currently effective Tariff Sections III.13.6.1.2.1(a), III.13.6.1.2.1(b), III.13.6.1.2.1(c), as well as portions of Section III.13.6.1.2.1, are being deleted. The remaining subsections of Section III.13.6.1.2.1 are being renumbered accordingly. More detail as to how Pay For Performance makes this offer requirement for Import Capacity Resources unnecessary is in the testimony of Dr. White.[164]

Also, a portion of Section III.13.6.1.2.1(e) is being deleted. That subsection requires a Market Participant submitting certain priced External Transactions supporting an Import Capacity Resource to link the transaction to an associated transmission reservation and NERC E-

[162] *See* Montalvo Testimony at 21-24.

[163] *See id.* at 22-24.

[164] *See* White Testimony at 169-172.

Tag by a certain deadline. Currently, subsection (e) also states that if the Market Participant fails to link the transaction to an associated transmission reservation and NERC E-Tag, the associated Import Capacity Resource shall be treated as having not delivered energy. This latter provision, stating the consequences of failing to link the transaction, is being deleted because under Pay For Performance, whether the Market Participant has linked the transaction is not relevant to the determination of the Import Capacity Resource's Actual Capacity Provided.

b. Poorly Performing Resources

Currently effective Section III.13.7.1.1.5 states that if a resource meets certain thresholds of poor performance, it shall be prohibited from participating in subsequent Forward Capacity Auctions and from otherwise assuming a Capacity Supply Obligation. Because Pay For Performance includes strong performance incentives and significant financial consequences for failure to perform, such special administrative provisions are no longer necessary. For this reason, Section III.13.7.1.1.5 is being deleted, along with a reference to that section contained in Section III.13.1.4.1.1.

c. Capacity Performance Bilaterals

As explained above, Capacity Performance Bilaterals under Pay For Performance are more simple than the Supplemental Availability Bilateral construct that they replace. As a result, currently effective Sections III.13.5.3.1.2, III.13.5.3.1.3, and III.13.5.3.1.4 are being deleted. The remaining provisions in Section III.13.5.3 are being revised to reflect the new Capacity Performance Bilateral construct. In addition, in several other sections of the Tariff, references to Supplemental Availability Bilaterals are being revised to refer instead to Capacity Performance Bilaterals, including Sections III.1.1, III.1.4.2, and III.13.5.

d. Charges To Market Participants With Capacity Load Obligations

Currently effective Section III.13.7.3, titled "Charges To Market Participants With Capacity Load Obligations," includes several minor conforming changes as a result of the Pay For Performance revisions. First, because the Pay For Performance provisions have been inserted earlier in Section III.13.7, currently effective Section III.13.7.3 is being renumbered as new Section III.13.7.5. This includes both the section numbers themselves as well as numerous internal cross-references.

Second, language is added in renumbered Section III.13.7.5 (which is Section III.13.7.3 in the currently effective rules) excluding Capacity Performance Payments from the definition of Net Regional Clearing Price. This is because the Net Regional Clearing price is defined, very

generally, as the sum of the sum of all payments to resources with a Capacity Supply Obligation divided by the total quantity of all Capacity Supply Obligations. While Capacity Performance Payments are indeed payments to resources with a Capacity Supply Obligation, they are structured as transfers among suppliers rather than charges to load, and hence are not properly included in the numerator of the Net Regional Clearing Price calculation.

e. Defined Terms

Section I.2.2 of the Tariff lists all of the capitalized, defined terms used in the Tariff. Consistent with the implementation of Pay For Performance, the defined terms section is being fully updated to include new defined terms established under Pay For Performance, to eliminate defined terms that will no longer be used with the elimination of existing FCM provisions, and to update section number references where provisions have been moved or renumbered. The defined terms revisions are being filed in two separate documents, because some of these defined terms changes must become effective in 2014 (with the market monitoring and mitigation changes),[165] while others must become effective with the balance of the Pay For Performance changes in 2018.[166]

f. Obsolete Provisions

Because the Pay For Performance mechanism is replacing the Shortage Event construct in the currently effective rules, and because it is a more simple design (largely due to its resource neutrality and lack of exemptions), large portions of the current FCM rules, especially in Section III.13.7 (home of the new Pay For Performance provisions), are being deleted.

First, the entire Shortage Event construct is being deleted. This includes the following currently effective Tariff provisions: III.13.7.1.1, III.13.7.1.1.1, III.13.7.1.1.1.A, III.13.7.1.1.2, III.13.7.1.1.3, and III.13.7.1.1.4. Some of these section numbers are re-used under Pay For Performance, others are being deleted.

Related to this, in several sections of the Tariff, references to "Shortage Event" are being updated to refer instead to "Capacity Scarcity Condition." These are Sections III.13.1.2.2.2.1(c), III.13.1.2.2.2.2(c), III.13.6.1.5.4.3.3.1, and III.A.8. In two of those sections, Section III.13.1.2.2.2.1(c) and Section III.13.1.2.2.2.2(c), revisions are also made to reflect the fact that Capacity Scarcity Conditions will not be "declared," they will simply occur under the circumstances as defined.

[165] *See* ISO's blacklined Tariff sheets effective June 1, 2014, submitted with this filing as Attachment I-1h.

[166] *See* ISO's blacklined Tariff sheets effective June 1, 2018, submitted with Part 2 of this filing as Attachment I-2b.

Also related to the deletion of the Shortage Event provisions, in Section III.13.3.4, what were references to currently effective Sections III.13.7.1.1.3(h) and III.13.7.1.1.3(i) are – because those sections are being deleted – being replaced with text similar to that included in those currently effective sections.

Second, because all resource types will be subject to the same monthly Capacity Base Payment provisions (in new Section III.13.7.1), most of the remaining provisions in current Section III.13.7.2, detailing monthly capacity payment by resource type, are being deleted. This includes Sections III.13.7.2.2 (Import Capacity), III.13.7.2.3 (Intermittent Power Resources), III.13.7.2.4 (Settlement Only Resources), portions of III.13.7.2.5 (Demand Resources), and III.13.7.2.6 (Self-Supplied FCA Resources).[167]

Third, again because all resource types will be subject to the same monthly Capacity Base Payment provisions (in new Section III.13.7.1), separate subsections detailing the various adjustments to capacity payments applicable to different resource types are being deleted. This allows for the deletion of most of old Section III.13.7.2.7, including III.13.7.2.7.1 (Generating Capacity Resources),[168] III.13.7.2.7.2 (Import Capacity), III.13.7.2.7.3 (Intermittent Power Resources), III.13.7.2.4 (Settlement Only Resources), III.13.7.2.5 (Demand Resources), and III.13.7.2.6 (Self-Supplied FCA Resources). Among the subsections being deleted as a result is Section III.13.7.2.7.5.4, which described Demand Resource Performance Penalties and Demand Resource Performance Incentives. Because those provisions are being deleted, it is also necessary to delete two references to those penalties and incentives, in renumbered Sections III.13.7.5 and III.13.7.5.3.1 (which are Sections III.13.7.3 and III.13.7.3.3.1, respectively, in the currently effective tariff).

Fourth, and again because all resource types are treated the same way under Pay For Performance, provisions detailing separate performance measures for different types of resources are being deleted. This includes Section III.13.7.1.2 (Import Capacity Resources), III.13.7.1.3 (Intermittent Power Resources), III.13.7.1.4 (Settlement Only Resources), III.13.7.1.5 (Demand Resources), and III.13.7.1.6 (Self-Supplied FCA Resources).

Fifth, as discussed above, the Pay For Performance design does not include any measurement of resource "availability." Hence, the main availability penalties provisions in currently effective Section III.13.7.2.7.1 are being deleted. This also requires the deletion of

[167] Several subsections are still applicable, however, and so are unchanged by the Pay For Performance revisions (except for renumbering and conforming of internal cross-references). Accordingly, current Section III.13.7.2.2.A is retained (but renumbered as Section III.13.7.1.3); current Section III.13.7.2.5.2 is retained (but renumbered as Section III.13.7.1.4); current Section III.13.7.2.5.4 is retained (but renumbered as Section III.13.7.1.5); and current Section III.13.7.2.5.4.1 is retained (but renumbered as Section III.13.7.1.5.1).

[168] Except for the Peak Energy Rent provisions, which have been moved (to new Section III.13.7.1.2) and modified under Pay For Performance, as discussed above.

numerous references to availability penalties in other areas of the FCM rules, specifically, in Sections III.13.2.8.1.1(d), III.13.2.8.2(b), III.13.6.1.1.2, III.13.6.1.2.1, III.13.6.1.5.2, and III.13.6.4.

g. Moving Demand Reduction Value and Capacity Value Provisions

Portions of currently effective Section III.13.7 describing Demand Reduction Values for Demand Resources are still needed in the FCM rules for purposes other than measuring performance. For this reason, currently effective Sections III.13.7.1.5.3, III.13.7.1.5.4, III.13.7.1.5.5, III.13.7.1.5.6, III.13.7.1.5.7, and III.13.7.1.5.8 are being moved into new Section III.13.1.4.1.3. Except for renumbering, these new provisions are identical to their existing counterparts. This move also requires the renumbering of several sections immediately after Section III.13.1.4.1.3. Moving these provisions reflects the fact that under Pay For Performance, a Demand Resource's Demand Reduction Value is not a parameter used in assessing its performance. For this reason, Section III.13.6.1.5.4.8(c), which addresses using audit results to calculate a Demand Resource's Demand Reduction Value, is also being deleted as no longer applicable under Pay For Performance.

Like the Demand Reduction Value provisions, currently effective Section III.13.7.1.5.1 and Section III.13.7.1.5.2 describing Capacity Values for Demand Resources and Distributed Generation, respectively, are still needed in the FCM rules for purposes other than measuring performance. For this reason, those sections are being moved to new Section III.13.1.4.6.2.3 and Section III.13.1.4.6.2.4, respectively. New Section III.13.1.4.6.2.3 is not identical to existing Section III.13.7.1.5.1 because the first portion of existing III.13.7.1.5.1 only applied prior to June 1, 2012 and is hence obsolete. Except for renumbering, new Section III.13.1.4.6.2.3 is identical to the latter half of existing Section III.13.7.1.5.1, which applied beginning on June 1, 2012. Except for renumbering, new Section III.13.1.4.6.2.4 is identical to existing Section III.13.7.1.5.2.

Along with this change, Section III.13.8.1(a)(v) is being deleted. That section requires the ISO to file the Capacity Value multipliers with the Commission as part of the informational filing made no later than 90 days prior to each Forward Capacity Auction. Such a filing is not necessary because the multipliers are stated expressly in the Tariff (in currently effective Section III.13.7.1.5.1, and in new Section III.13.1.4.6.2.3 under Pay For Performance) and do not change from year to year. And because those numbers are specified in the Tariff, if any change were to be made, it would be discussed with stakeholders and filed with the Commission.

h. Tables Of Contents

Finally, the table of contents for each of the documents being revised under Pay For Performance is being updated to reflect the various added, deleted, and renumbered Tariff sections.

VII. 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. However, the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations.[169] Notwithstanding its request for waiver, the ISO submits the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

35.13(b)(1) – Materials included herewith are as follows:

- This transmittal letter
- Testimony of Peter Brandien
- Testimony of Matthew White
- Testimony of Peter Cramton
- Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand
- Testimony of Marc Montalvo
- Affidavit of Todd Schatzki and Impact Assessment by Analysis Group, Inc.
- The ISO's blacklined Tariff sheets effective June 1, 2014
- The ISO's clean Tariff sheets effective June 1, 2014
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent

35.13(b)(2) – The ISO requests that the Market Rule changes set forth herein become effective as set forth in Section III above.

[169] 18 C.F.R. § 35.13 (2012).

35.13(b)(3) – 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 of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/committees/nepool_part/index.html. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing 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 Section VI of this transmittal letter.

35.13(b)(6) – The ISO's approval of the Market Rule changes submitted herein is evidenced by this filing. The Participant Processes required by the Participants Agreement have been complied with.

35.13(b)(7) – The ISO has 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 Market Rule changes herein does 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 revision filed herein.

VIII. CONCLUSION

For all of the reasons discussed above, the ISO respectfully requests that the Commission accept the Pay For Performance design without modification to become effective as requested above in Section III.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: _____/s/_____

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Dated: January 17, 2014

Attachment I-1b

Testimony of Peter Brandien on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

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

I. INTRODUCTION

Q: Please state your name, title and business address.

A: My name is Peter Brandien. I am employed by ISO New England Inc. (the "ISO") as the Vice President of System Operations.

Q: Please describe your educational background and work experience.

A: I have a Bachelor of Science degree in Electrical Engineering from the University of Hartford. I have over 26 years of energy industry experience in control room operations. I joined the ISO in 2004 as the Vice President of System Operations. In that capacity, I am responsible for the day-to-day operations of New England's bulk power system and oversight of transaction management, outage coordination, unit commitment, economic dispatch, system restoration, operator training, certain compliance functions, and development of operating procedures. Prior to joining the ISO, I spent 17 years at Northeast Utilities, most recently as Director of Transmission Operations. Before Northeast Utilities, I served in the United States Navy as a submarine nuclear propulsion plant operator/ electrician.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony?

A: One of the predicates for the ISO's Pay For Performance proposal is the fact that generators are not performing adequately and need better incentives to do so. My testimony is offered to describe these performance issues, various aspects of which have been described in prior documents.[1] In this testimony, I endeavor to present the entire spectrum of performance issues, which, together, threaten the ISO's ability to operate the system reliably.

Q: Can you summarize your conclusions?

A: My testimony will show that the performance problems among the generating fleet in New England are pervasive and the deteriorating performance is threatening a reliable electric supply. These performance problems are not limited to a specific segment of the fleet, and are worsening.

While the performance issues are fleet-wide, gas supply is one of the core issues challenging reliability. Very simply, with the increase in domestic gas supplies,

[1] *See, e.g.,* Winter Operations Summary: January – February 2013 at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf; Analysis Group's Analysis of Reserve Resources: Activation Response following Contingency Events at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf; Addressing Gas Dependence at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf.

generators' demand for gas has skyrocketed, but there is simply not enough infrastructure to deliver that gas to all of the parties in New England that want it. This has put the ISO in the position of monitoring the region's gas supply and, when the pipelines are constrained, managing the output of large portions of the generating fleet based on available fuel supply. This is not the appropriate role for the ISO; we should be focused on operating the power system, not the fuel supplies of the region's generating fleet.

When the gas-fired generators that produce more than half of the region's electricity cannot procure fuel, the ISO must find replacements. We often turn to oil- and coal-fired units, but their performance as a group is deteriorating as well. They have the highest outage rates of any category of generators and, in peak hours of peak days, unit operating issues result in them reducing their capacity more than any other group. These units also have difficulty starting on time (or starting at all).

While the gas, oil and coal units represent the vast majority of New England's capacity, they do not represent the entire spectrum of performance problems. As my testimony shows, the performance of the entire fleet is deteriorating. Nearly every category of generator has seen its rates of unplanned outages increase. Resources do not respond adequately to contingencies. Units are failing to staff their generators. Liquid fuel inventories are kept low, and units are mothballing their ability to switch fuels.

What does this mean? It means that we need a fundamental change. Simply put, generators do not have incentives to perform.

To be clear, this is not just a gas problem. Even when the pipelines are not constrained, there is always the potential for an interruption in gas service to the thousands of megawatts of energy supplied by a single pipeline. Accordingly, even if the pipelines expanded overnight, we need all generators (including non-gas-fired generators) to perform in order to mitigate the systemic risk of a correlated outage.

We have a fleet-wide problem and it cannot be solved simply through improvements to the ISO's operating practices and markets – although those have been undertaken. In terms of operating practices, the ISO has advocated for better pipeline information sharing, changed commitment practices under certain circumstances, and even hired a gas industry professional to help forecast gas supply problems. On the markets side, the ISO has proposed changes to increase offer flexibility, accelerate the timelines in the Day-Ahead Energy Market, increase reserves, enhance reserve market incentives, improve generator auditing, and redefine Shortage Events in the Forward Capacity Market ("FCM"). The ISO has even adopted an out-of-market solution in the form of a winter reliability program.

In short, the ISO has taken many steps to allow reliable operation of the system in the face of these mounting problems, but these steps can only achieve so much; they do not solve the underlying problems and will not help us avoid more severe reliability problems in the future. At the end of the day, the region needs its resource owners to make investments – investments in firm fuel, fuel inventory, alternate fuels, maintenance, appropriate staffing, dual fuel capability, and new resources. The ISO's role should be to provide the incentives for those investments, which is why we are proposing modifications to the incentives in the FCM.

Q: How is your testimony organized?

A: I have divided my testimony into three main sections. In Section III, I discuss the risks related to the increasing dependence on gas. These risks are manifest in the sudden and sometimes sizeable unavailability of generation due to gas supply issues. I also discuss how these risks are magnified by the "just-in-time" nature of the gas supply and the dependence of multiple generators on a single pipeline that can be disrupted on short notice. (This is the "systemic risk problem.")

Section IV describes the performance problems of the region's oil and coal units, which I sometimes refer to herein as "fossil steam" units. In the past, New England has relied on the diversity of its fleet to mitigate problems like our current gas issues. Unfortunately, a significant portion of the region's fossil steam generators, which comprise about 25% of the fleet, cannot reliably provide

an alternative when gas-fired generators are unavailable. This situation is evidenced in these generators' outage rates, problems starting on time (or at all), and unit-specific operating issues that result in reductions to its economic maximum operating levels ("ecomax") on peak demand days.

In Section V, I discuss performance issues that span the entire fleet. These include increasing outage rates across nearly all generator categories, poor responses to contingencies, inadequate staffing, and failure to maintain oil inventory.

III. RISKS RELATED TO THE INCREASING DEPENDENCE ON GAS

A. Gas Dependence

Q: Please discuss New England's increasing demand for gas.

A: New England's reliance on natural gas for electric generation has increased dramatically over the past decade. In 2000, natural gas-fired generators supplied approximately 15% of New England's electricity; currently, natural gas-fired generators supply approximately 51% of the region's electricity. On most days, nearly the entire fleet of dispatchable resources available to ISO system operators consists of gas-fired generators.

A contributing factor to this increase is the abundance of shale gas in the last few

years, and the resulting lower cost of natural gas compared to other fuels. The increased demand for this gas, both to fuel electric generators and for home heating and other purposes, has increased competition for the use of the northeast interstate natural gas pipelines to transport the gas to New England. In recent years, these pipelines have become constrained relatively often, reducing their operating flexibility and ability to support the region's generation fleet. Although gas availability for power generation is a concern throughout the year, the problem is worse during cold weather, when home heating use peaks, and during pipeline maintenance and construction.

Q: Please discuss New England's supply of gas.

A: In short, the supply is insufficient to meet the demand. To quantify the problem, the ISO commissioned ICF International, LLC to perform a study, released in July 2012, of the capacity of the natural gas pipelines serving New England.[2] The study concluded that, in the various scenarios studied, "there is not enough gas supply capability …to meet the anticipated power sector gas demand." Specifically, there was a gas supply deficit into the region in every scenario on a winter peak day in each year from 2012 through 2020. These deficits ranged from a low of 1,500 MW on a day where the 50/50 forecast was used, to a high of

[2] The study can be found at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2012/gas_study_public_slides.pdf. *See also* ICF's whitepaper entitled Assessment of New England's Natural Gas Pipeline Capacity to Satisfy Short and Near-Term Electric Generation Needs at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.pdf.

5,700 MW on a day in winter 2020 where the 90/10 forecast is used and there is a large non-gas plant out-of-service.[3] On the winter days studied, gas transportation capabilities are usually below the amount needed to supply the gas required for the activation of the operating reserve units on the system. The deficits grow when existing non-gas generators are replaced with additional gas-fired resources and in a variety of contingency scenarios (e.g., loss of a pipeline or interruption of supplies of liquefied natural gas ("LNG")).

The study noted that, in other seasons, the existing pipeline capacity available for electric generation will shrink as use by gas distribution companies increases. Notably, the study was conducted assuming that all pipelines are fully available in each scenario (i.e., there are no contingencies or maintenance) and that flows on the various pipelines are perfectly coordinated in order to maximize the throughput on the pipeline system; accordingly, ICF has acknowledged that the study *overestimates* gas availability.

Input from regional pipeline companies and electric system operating experiences substantiate the study's conclusions. The pipelines have confirmed that the pipes connecting New England from supply points to the west, including the Marcellus shale fields, are becoming constrained for most of the winter and are constrained

[3] The 50/50 forecast has a 50% chance of being exceeded, while the 90/10 forecast has a 10% chance of being exceeded and is therefore a more conservative estimate.

or operating near capacity in periods other than the winter. For example, as reported by Spectra Energy Corp., the owner/operator of the Algonquin Pipeline, at its 2012 customer meeting, the number of days that the pipeline is restricted through the Cromwell compressor station in Connecticut increased from a single day during the 2009/2010 winter to over a hundred days during the 2011/2012 winter. The Kinder Morgan Tennessee Pipeline has also experienced a significant increase in the number of days that the pipeline is restricted through compressor Station 245 (upstate New York). Winter restrictions have increased from 42% during the 2009/2010 winter to over 99% of the days during the 2011/2012 winter. In addition, the Tennessee Pipeline has begun experiencing restrictions during the summer months. Specifically, summer restrictions have increased to 78% of the days in the summer of 2011. In contrast, in 2009, there were no restricted summer days.[4]

Q: Is LNG an alternative?

A: The availability of alternatives is shrinking as well. LNG, which traditionally has served as additional fuel capacity for gas-fired generators during the winter, is being shipped to other parts of the world given the sustained high global price and the lack of firm gas customers, which has resulted in deliveries to the northeast

[4] For more information, *see* Addressing Gas Dependence at http://www.iso-ne.com/committees/comm_wkgrps/ strategic_planning_discussion/materials/natural-gas-white-paper-draft-july-2012.pdf. *See also* the December 12, 2013 Forbes article entitled "Cold Snap Sends Energy Prices into the Stratosphere in New England" at http:// www. forbes.com/sites/williampentland/2013/12/12/cold-snap-sends-energy-prices-into-stratosphere-in-new-england/.

declining.[5] As the Commission noted in its Winter 2013-14 Energy Market Assessment:

> LNG is likely to remain in short supply this winter with price spikes in New England not sustained long enough to incentivize LNG cargos. GDF Suez, the owner of the Everett LNG plant in Massachusetts, is under contract to divert almost half of its supplies to higher priced areas elsewhere in the world. Everett LNG now supplies only Mystic Power Plant Units 8 & 9, and local above ground LNG storage, but does not send out significant quantities of regasified LNG into interconnecting pipelines. Repsol, the owner of Canaport LNG, does not anticipate receiving many cargos this winter or going forward. As of mid-2013, Repsol is under contract to receive about two shipments of LNG a year, just enough to keep the terminal operating.[6]

Q: Does it make sense to you from an operational perspective that the two LNG facilities that serve New England are not being fully utilized by generators?

A: No. As an operator, I would like to see those facilities able to provide gas to New England's generators when the pipelines from the west are full. This would significantly enhance reliability by allowing more gas generators to operate in tight system conditions.

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[5] "LNG imports into Everett were at their lowest levels during January and February 2013, with no cargos imported under short-term or spot provisions, compared with five such cargos during the same period in 2012." See p. 10 of the ICF paper Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_ impacts_ white_ paper_11-18-2013.pdf.

[6] *See* the October 2013 report at http://www.ferc.gov/CalendarFiles/20131017101835-2013-14-WinterReport.pdf.

Q: If world LNG prices are higher than those in New England, why should these facility operators buy this LNG?

A: If generators are given increased financial incentives to operate, they would have the incentive to sign option agreements with the LNG facilities that could assure that gas is available when needed.

Q: Would dual fuel capability at gas generators significantly reduce the gas risks you have discussed?

A: Yes. Dual fuel generators can provide valuable fuel diversity and flexibility by switching from one fuel to another. This flexibility can be utilized not only to replace a fuel that the generator has run out of, but also to preserve gas supplies that the market can allocate to other, non-dual fuel generators. In fact, in terms of ensuring reliable fuel service, the Analysis Group has stated that implementation of dual fuel capability is likely the lowest-cost option to ensure fuel security, when compared to procuring firm gas pipeline transportation or LNG.[7] These benefits can be realized, however, only when generators have the economic incentives to install, maintain, test, and procure fuel for dual fuel resources. Unfortunately, rather than increasing, we have seen a marked decline in dual fuel capability.

[7] *See* p. 19 of Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives (September 2013) in Attachment I-1g of this filing.

Q: What evidence is there that generators are mothballing or otherwise allowing their dual fuel capability to become inoperable?

A: The ISO's Capacity, Energy, Load and Transmission ("CELT") Reports show that generators are mothballing their dual fuel capacity. In the 2004 CELT report, generators reported 9,541 MW of dual fuel capability, or 30% of total summer system capability. The 2012 CELT report shows that only 18.7%, or 6,132 MW, of summer capability are dual-fuel capable. In other words, in less than ten years, the region has lost more than 3,400 MW of dual fuel capability.[8] We believe that this problem may be worse than reported, with other generators failing to maintain their dual fuel capability through testing and maintenance. In fact, to encourage testing, the ISO included compensation for dual fuel testing in its 2013-2014 Winter Reliability Program.

B. Gas Reductions

Q: How is this supply and demand problem evident in New England?

A: The problem is evident through sudden, sizeable reductions in gas units' output. To illustrate the problem, we provide examples of generation losses in excess of 700 MW that resulted from gas supply issues in the years 2010-2013. **Figure 1** below shows these large reductions, which can last for periods of less than four

[8] *See* Section 1.3 of the 2012 CELT report at http://www.iso-ne.com/trans/celt/report/2012/2012_celt_report.pdf and page 3 of the 2004 CELT report at http://www.iso-ne.com/trans/celt/report/2004/2004_CELT_Report.pdf.

hours (10/13/2012), or extend over multiple days (3/19/2013). The number of simultaneously affected units also varies, and ranges from two (12/28/2010) to ten (2/22/2011) in the examples shown below.

Figure 1: Examples of Significant Generation Losses as a Result of Gas Supply Issues

Date	Hours of reduction	Max Number of Units Concurrently Reduced	Maximum Concurrent Average Reduction (MW)	Average Reduction (MW)
12/10/2010	20.5	6	787	344
12/28/2010	9.2	2	791	610
1/22/2011	23.1	8	815	438
2/20/2011	19.7	5	732	449
2/21/2011	15	9	1013	698
2/22/2011	25	10	1375	851
7/5/2012	17.6	8	813	568
10/13/2012	3.9	7	819	559
2/9/2013	27.8	5	1311	532
3/19/2013	58.6	7	846	338

Q: Does the frequency of these reductions comport with your experience?

A: No. I believe that the issues related to gas dependency are actually more critical than the data implies. The severity of these issues has been masked, because

system operators have adapted to chronically limited gas supplies and regularly take actions that diminish the frequency of generation outage impacts due to gas reductions. Specifically, operators monitor pipeline bulletin boards, call generators and pipelines, and attempt to keep track of LNG inventory levels. The operators monitor generators' scheduled volume of gas in comparison with their anticipated electric energy schedules, and communicate concerns to the generators, particularly when there is limited flexibility on the pipelines. If operators are uncertain about gas supply, they will hedge this uncertainty through supplemental commitments of other, preferably non-pipeline fueled, generators and may also reallocate operating reserves to conserve fuel by, for example, posturing pump storage units (pumping and generating) to preserve water for contingency response.[9] More formally, the ISO has attempted to forestall the likelihood of electric system capacity deficiencies due to gas supply limitations by implementing a Winter Reliability Program for the current winter. Among other things, this program pays oil-fired generators to keep oil inventory on hand in case they are needed to run this winter.

In sum, I believe that the ICF study and our surveys of generators' fuel supplies are more accurate indications of the scope of the gas dependency problem than the actual incidence of gas reductions to date. These surveys indicate that many

[9] Many of these actions require the payment of "uplift" to generators, which results in increased costs to consumers in the region and depressed electricity prices by undermining the price signals that guide resources' fuel procurement.

gas units only procure gas for their anticipated run as scheduled in the prior day, although, in every hour of every day, operating reserves are allocated among these gas units. If the operating reserves were activated due to a source loss on a tight gas supply day, the likelihood of these generators arranging for additional gas after supplying the requested energy would be low, and system operators would be required to implement emergency actions to maintain reliability; in the worst case, these actions would include load shedding. In short, I believe we are managing around what has become a chronic gas supply problem, and this active management has created the false impression that the gas supply constraints are less dire than they really are.

Q: Please elaborate on your statement that gas disruptions and related reductions in generation can occur suddenly.

A: The fuel supply chain for gas-fired generators is fundamentally different than that of coal and oil. Coal and oil are stored on-site, and generators may have sufficient inventory to afford them days or weeks of operations in the event of a disruption in the supply chain. Because gas is not stored on-site, generators are dependent on "just-in-time" fuel deliveries, which may be unavailable or disrupted with little or no notice. An example using Storm Nemo is illustrated in **Figure 2**. Storm Nemo occurred on Friday, February 8, 2013 and continued into Sunday, February 10, knocking out power to more than 645,000 distribution customers, primarily in southern New England.

Figure 2: Sudden, No-Notice Loss of Generation During Storm Nemo

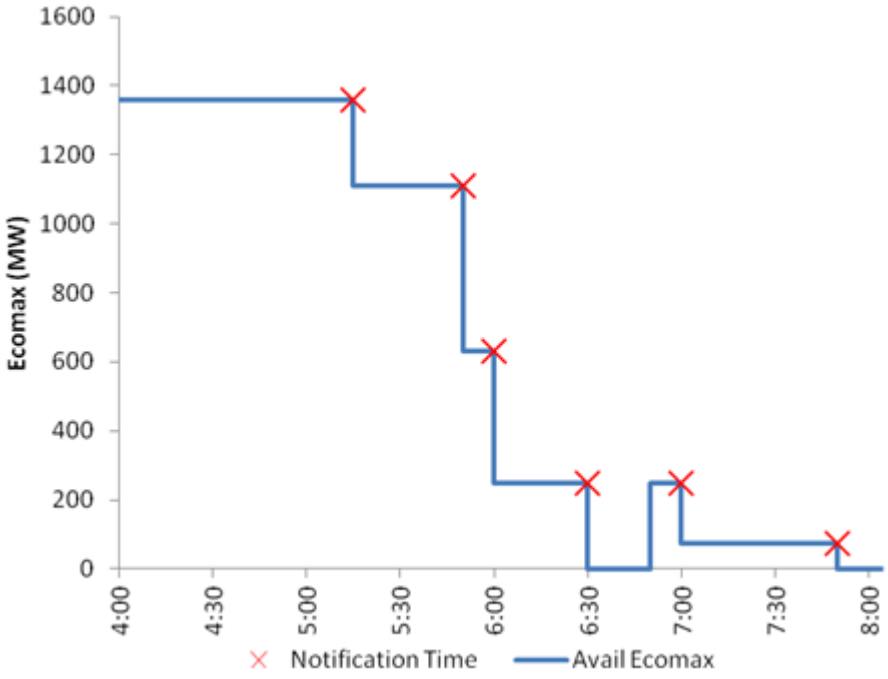


Figure 2 shows reductions in unit capability due to reduced gas supplies, and the notice provided to the control room for each of the reductions. Specifically, the blue line represents the cumulative ecomax across five gas-fired generators that reduced their output capability due to reduced fuel availability on the morning of February 9, 2013; the red X's show the notification time for each of these reductions based on communication between the generators and the control room. In this particular example, the overall reduction was severe, resulting in a loss of more than 1,300 MW of capacity without a generation contingency or physical problem other than fuel supply. As shown by the graph, the majority of this reduction occurred very quickly, with 860 MW of ecomax lost within fifteen minutes. Significantly, each time the ecomax available on these units is reduced, we can see that the control room has no advance notification.

C. Causes of Gas Reductions

Q: Beyond the imbalance between supply and demand, what specifically is causing gas reductions?

A: Gas reductions can occur as a result of procurement problems or pipeline problems. Procurement problems occur when a generator hasn't procured enough gas. This issue generally arises when the ISO directs the generator to produce electricity in an amount that exceeds the unit's day-ahead commitment because load is greater than expected or there is a contingency on the system. Generators are required to produce this energy; as affirmed by the Commission, generators must offer into both the day-ahead and real-time energy markets a MW amount equal to or greater than its Capacity Supply Obligation when the resource is physically available. The Commission has agreed with the ISO that generators must respond to the ISO's directives to start, shutdown or change output levels, and must keep their supply offers open throughout the operating day.[10] Pipeline problems refer to the pipeline's inability to deliver gas to generators as a result of pressure problems, fuel quality problems, maintenance, or operational flow orders brought on by high demand during times of peak residential consumption. These types of operational issues are to be expected; much like electric power system operators, natural gas pipeline operators must balance

[10] *See New England Power Generators Association, Inc. v. ISO New England Inc*., 144 FERC 61,157 (2013) at P 49.

injection and withdrawals to maintain reliable operations and may, at times, be required to interrupt operations at different locations to protect the system.

Q: Please discuss the nature of procurement problems.

A: Natural gas is sold through brokered markets, and, in a separate transaction, is transported through an interstate pipeline system. The pipelines offer a number of transportation services that vary in priority (and expense). Historically, the companies that distribute natural gas to home heating customers (Local Distribution Companies or "LDCs") purchase most of the pipelines' highest priority, most expensive "firm" (non-interruptible) pipeline capacity. (In fact, these purchase commitments are the de facto financing that pipelines rely on to build and expand their infrastructure.) The capacity that is not utilized by the LDCs and other firm customers is available for purchase by generators.

As indicated by the ICF study discussed above, there is insufficient pipeline capacity to supply both the LDC loads and electric generation during times of peak gas usage, which generally occurs on cold winter days. The issue also arises when pipelines schedule major maintenance or construction outages, which the pipelines coordinate with their firm customers (i.e., not generators).

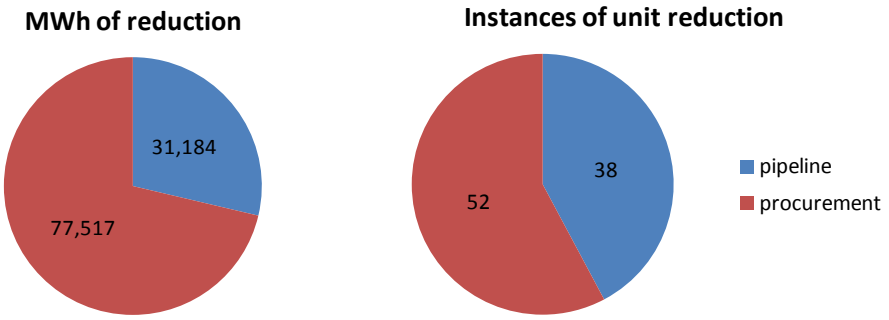
Accordingly, if generators have not made arrangements for fuel in advance, they often may not be able to secure gas transportation when the ISO schedules them beyond their day-ahead commitment. (As discussed above, generators are obligated to produce energy in excess of their day-ahead commitment if the

requested amount is less than their offer.) The challenge of rapidly securing additional gas transportation can be exacerbated by timing issues and high prices during periods of peak gas demand.

Q: What is the relative frequency of procurement problems?

A: The ISO has classified gas reductions as either procurement problems or pipeline problems. Since the classification of these events began, most events and MWhs of unit reduction (computed as average event reduction multiplied by hours of event duration) have resulted from procurement issues. The breakdown for 2013 is displayed in **Figure 3**.

Figure 3: Gas Reductions as a Result of Procurement v. Pipeline Issues



Q: Can you give examples of procurement problems?

A: We investigated events between January 4, 2012 and September 28, 2012 in which generators failed to follow dispatch instructions due to gas availability issues. In each case, the generators were asked to run within the parameters of their offers, but failed to do so because they did not have adequate fuel arrangements. These events involved 13 unique units. Although the performance issues occurred throughout the study period, there were concentrations in June,

July and September, with six different failures in June and September and seven in July. The following are examples of these events:

- In January, a unit decreased its offer price for the next day during the reoffer period, after which it was committed. The ISO called the unit and the unit confirmed that it had gas ("gas is yes"). Three hours into the operating day, the ISO received a call from the unit that it would be coming offline because it had "used up all [its] gas for the gas day." When the ISO operator asked what had happened, he was told "you guys called, we have it logged. You guys called numerous times making sure we had gas for the day … and each time we call them [the participant's dispatch desk] they say, 'yes, tell them yes' and that's what we told you guys. I … you know, I'm just the middle guy. I don't know what to tell you." In later conversations, the participant attributed the incident to confusion caused by the differences in the gas and electric days.

- In June, the ISO committed a unit in the day-ahead market, after which the unit increased the price of its offer. The ISO called the unit to verify that it had nominated and scheduled gas. On the operating day, during its start up, the unit called the ISO and said that it was having trouble getting gas. It subsequently failed to generate in accordance with its offer.

- In June, a unit received a day-ahead commitment, after which the ISO called to confirm that the unit had procured and scheduled gas. On the morning of the operating day, the ISO received a call from the unit's supplying gas pipeline, which expressed concern about the lack of gas scheduled for three units, including the committed unit. The ISO contacted all three plants to confirm they had gas, but did not hear back from the committed unit. A few hours later the unit called and reported "gas constraints" that required it to reduce its output.

- In September, a participant submitted offers and was not committed day-ahead. When it was committed in the Reserve Adequacy Assessment process to satisfy operating reserve requirements, the unit stated that it could not procure enough fuel to make the run for operating reserves as committed, and its alternate fuel (oil) was unavailable as well. Later, the unit indicated that it could have burned the alternate fuel but chose not to because its offer did not reflect the higher fuel cost.

- In September, after offering for each hour, a unit received a day-ahead commitment for all but the first six hours of an operating day. When the unit was contacted to run in those first six hours for reliability reasons, the unit stated that it had not procured enough fuel.

Unfortunately, these incidents – in which generators dispatched in accordance with their offers renege because they haven't procured gas – have become commonplace. System operators can no longer be assured that offers are accurate, or that generators will perform when needed.

D. The Systemic Risk Problem

Q: What is the significance of pipeline problems?

A: As noted above, pipeline problems refer to the pipeline's inability to deliver gas to generators as a result of pressure problems, fuel quality problems, maintenance, or operational flow orders. While pipeline problems account for fewer reductions than procurement problems, the problems are potentially much more severe because of the possibility that they will affect multiple units that simultaneously draw from the pipeline. In other words, pipeline problems are a "systemic risk" because they could lead to a correlated outage involving multiple generators (including reserve units) simultaneously. To illustrate this problem, consider that a single pipeline can supply generators representing thousands of MW of electricity. Accordingly, this systemic risk can lead to serious reliability issues in the New England region.

As an example, a pipeline could have a compression problem or a segment of pipe that must be isolated, thereby restricting throughput. When this happens, gas pressure can drop, resulting in the requirement that multiple units reduce their gas

draw or come off-line to maintain the reliability of the pipeline system. Units that are further down the pipeline may be affected as well, and this contributes to New England's supply problems, since we are at the end of the supply chain. In fact, ICF International, LLC has recently written a white paper that describes the gas supply issues that can arise in New England as a result of gas usage in New York.[11]

Q: Do you believe that the systemic risk problem is likely to lead to a correlated outage?

A: I do, for the reasons discussed above, including our increasing dependence on gas and the suddenness with which gas supply issues arise. In fact, we have already had some "near misses."

Q: Can you describe situations where New England narrowly missed a catastrophic correlated outage?

A: January 28, 2013 was a "near miss." It was a cold day, with Hartford temperatures 2° F lower than forecast and Boston temperatures 7° F lower than forecast. As the region approached peak hours, a gas-fired plant tripped offline due to pipeline pressure issues, resulting in a loss of nearly 300 MW of capacity.

[11] *See* the ICF paper Gas-Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.pdf.

At 17:17, an oil-fired unit tripped offline, resulting in an additional loss of more than 400 MW of capacity and a deficiency in operating reserves and total ten-minute reserves. The operating reserve deficiency lasted for 19 minutes, and required the implementation of Master/Local Control Center Procedure No. 2 ("Abnormal Conditions Alert"), dispatch of 373 MW of demand response pursuant to Operating Procedure No. 4 ("Action During a Capacity Deficiency"), and the posturing of a hydroelectric plant. Had the pipeline pressure issues been more severe and affected more than one generator, the problem could have easily escalated, especially given the contingent loss of a large oil-fired unit.

In another example, on the afternoon of December 10, 2010, without notice to the ISO, the gas pipelines had to reduce the supply of gas to generators within New England, equivalent to approximately 900-1,000 MW. In particular, one pipeline reported serious problems with gas pressure with the potential to interrupt gas flow to certain generators due to generators over-drawing their gas nominations. An additional 800 MW of gas-fired generation was at risk over the peak load hour due to questionable gas supplies.

To date, we have been able to manage through these and other operational issues. We have been fortunate that, so far, weather, non-gas generator outages, and gas reductions have not converged to create a catastrophic correlated outage.

E. Alleviating Gas Dependence

Q: What can be done to mitigate the risk of gas supply issues?

A: To mitigate these risks, the ISO has advocated for enhanced communications with gas pipelines and increased its information gathering from generators about fuel supplies. That said, these problems should not be managed indirectly through ISO operations; they should be managed directly through the actions of the generators. To that end, the ISO has worked to improve markets, including through the Pay For Performance changes, to give generators the incentives to avoid these sorts of problems and ensure that they are able to produce electricity. With the right incentives, there are a number of actions that generators could take to significantly mitigate these risks. These include investing in sufficient firm gas transportation and/or securing back-up LNG. According to the Analysis Group, the most cost-effective solution for reliable fuel service may be investment in (and maintenance of) dual fuel capability.[12]

[12] *See* p. 19 of Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives (September 2013) in Attachment I-1g of this filing.

IV. PERFORMANCE PROBLEMS OF THE REGION'S "FOSSIL STEAM" UNITS

Q: When gas generators are unavailable, what other resources can you call on?

A: After gas-fired generation, the next largest segment of the region's capacity is oil-fired generation, at 21.6%. Coal is also a significant segment at 7.8%.[13]

Q: Can you measure the performance of these units?

A: Yes. Because at times it is more accurate to measure performance by technology rather than fuel, I sometimes refer to the performance of "fossil steam units" instead of coal- and oil-fired units. These fuel and technology categories have significant overlap, as all units that operate primarily on coal and about 70% of generation fired primarily by oil are fossil steam units.

We used three metrics to measure the performance of these units. Specifically, we measured reductions in fossil steam units' ecomax on peak days; the ability of oil- and coal-fired units to start on time; and outage rates of fossil steam units.

Q: Are these units reliable performers?

A: By any measure, a significant portion of these units have not performed reliably. In part, this is due to their design. These units were built as base-load or

[13] *See* pp. 102-103 of the 2013 Regional System Plan at http://www.iso-ne.com/trans/rsp/index.html.

intermediate units, and were intended to be run 24/7 or, at a minimum, five days a week. However, given the relative prices of oil and gas, it is not currently profitable for these units to run on a day-to-day basis, and, as a result, they are often off-line for months at a time. The ISO calls them in response to contingencies or during peak load periods, but these units were not built to run intermittently and on short notice, and have trouble starting within their claimed start time, or, in the case of older non-combined cycle units, sustaining an extended run due to tube leaks and other metal stresses.[14]

A. Fossil Steam Units' Ecomax Reductions on Peak Days

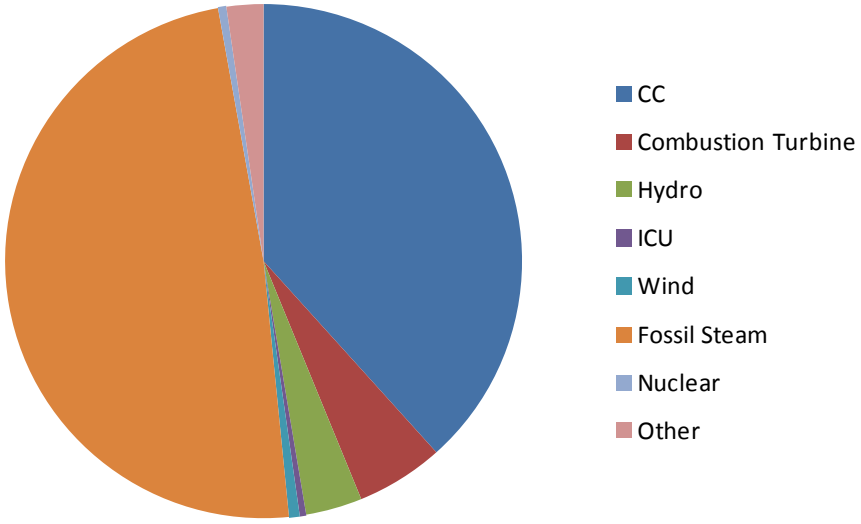
Q: Have these units failed to produce electricity when needed?

A: Yes. For example, on July 19, 2013, during a heat wave, there was dramatic underperformance by generators (as compared to their Capacity Supply Obligations) despite significant notice that they would be run. Specifically, 4,611 MW of generators' total Capacity Supply Obligations were unavailable. Four of the five top underperforming units were fossil steam units.

[14] Increased notice often improves performance, and may be feasible when we are aware that gas reductions may result, for example, during an upcoming storm where we expect gas demand to be high. However, this practice can lead to the payment of Net Commitment Period Compensation to these units, which is an out-of-market cost that participants have difficulty estimating, and can suppress energy market prices because other units are dispatched down to account for the unexpected early output on the system.

Figure 4 shows underperformance on July 19 by technology type as a percentage of the total MW by which units underperformed on that day. As the chart indicates, nearly half of the underperformance comes from fossil steam units, despite the fact that they represent about a quarter of the capacity on the system.

Figure 4: Underperformance on July 19 by Technology Type



Q: Does your conclusion about the poor performance of fossil steam units extend to system operations on dates other than July 19?

A: Unfortunately, yes. We examined data from the beginning of the FCM to the present to review how resources perform relative to their Capacity Supply Obligations over time. We concluded that fossil steam units are the biggest contributors to underperformance.

Q: What methodology did you use?

A: For this analysis, we looked at the five days with the highest peak load in each year from 2010 through 2013 (for a total of 20 days), because these are the days that the fossil steam units would likely be needed to run. We quantified the MW by which units reduced their ecomax below their Capacity Supply Obligation in the peak hour of each of these days, and then examined performance based on technology type. The results are shown in **Figure 5**. The blue line in the graph is measured against the vertical axis on the right, and shows the average peak load across the five peak days for each year.

Figure 5: MW of Reduction in Ecomax by Technology Type During Peaks

Q: What conclusions did you reach?

A: Looking at reductions across technology type shows fossil steam units to be the largest contributors to reductions in almost every year,[15] although they are only about a quarter of the fleet. These units have consistently high reductions as compared to units of other types. In years with lower peak loads such as 2011 and 2012, it follows that the system is less stressed, the units are called upon less frequently, and fewer reductions are made.

B. Oil- and Coal-Fueled Generators' Start-Up Problems

Q: Do oil- and coal-fueled units have difficulty starting?

A: Yes. Based on their experience running the system, operators identified the units known to most commonly have startup issues. The identified units are all either coal- or oil-fueled generators and, together, account for approximately 3,740 MW of capacity (about 11% of total generation capability). We assessed the performance of these units when they were scheduled through the Security Constrained Reserve Adequacy ("SCRA") over the period January, 2005 through September, 2013.

Q: What methodology did you use?

[15] Hydro units have the highest EFORd in 2010 because of one unit's protracted outage. Without this anomaly, fossil steam units would have the highest EFORd in 2010 as well.

A: We used the finalized SCRA case schedule that is shared with units on the evening prior to the operating day[16] to determine the expected start time for each unit. We defined a "late" start as one where the unit's real-time output reaches the economic minimum at some point after the hour indicated in the SCRA case. We defined a "failed" start as one where the real-time output did not reach its economic minimum at any time during the scheduled run.[17]

Q: What was your conclusion?

A: Over the 8.75 years studied, all except two of the studied units have been late or completely failed to start in at least 20% of scheduled RAA starts. Some have fared even more poorly; the worst performer failed in 13% of scheduled starts and was late for 31%, resulting in only 56% of its scheduled starts being on time. The worst four units were late or failed to start in over 30% of all scheduled starts.

Q: Is the problem static over the years studied?

A: No. The trend shows the problem worsening. In fact, the missing MWh from the units studied more than tripled between 2009 and 2013.[18]

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[16] On May 23, 2013, this time was moved forward from 10 p.m. to 5 p.m.

[17] This analysis compares the SCRA schedule with the unit's behavior in Real Time. The analysis will therefore miss any communication between the control room and the unit taking place after the SCRA results are created. For example, if, after the SCRA and during the operating day, the operators called a unit and asked it to come on two hours later than its SCRA schedule, this new start time would not be captured and the analysis would show the unit as being two hours late for its SCRA start time. These types of communications are not typical and I do not expect that they would materially affect the results of the study.

[18] We compute the missing MWh as (SCRA Sched MWh – RT Metered MWh).

Q: What is the impact of the "missing MWh"?

A: Very simply, when a unit starts late or fails to start, we need to replace the missing MWh. If we replace them with generation from a gas-fired unit, we run the risk that the unit will use up its allotted gas and transportation rights, rendering it unable to run later in the day. More broadly, use of gas can contribute to the systemic risk problem and the possibility of correlated outages.

To avoid the "missing MWh," operators often attempt to manage around these coal- and oil-fired units' performance problems by starting the units earlier than necessary or starting extra units to cover for the possibility that the most economic units do not start or are delayed. This contributes to uplift and reduces electricity prices through extra commitments, which generators have long noted distort the market and undermine the price signals that guide their investments and operation.

Q: Can you provide examples of late or failed starts?

A: Yes. In July, 2012, a dual fuel resource operating on oil failed to start in accordance with its offer, minimum notification and startup time parameters because it had to "sequence" its multiple onsite generators, both of which were close to a cold start. In another example, an oil unit offered into the markets but did not receive a day-ahead schedule. When it was called on to operate for reliability reasons within its notification time of twelve hours, the unit stated that it could not start "due to turbine issues" and asked for a delay. When the unit had

not shown up forty minutes after the ISO had been told it would be on "any minute," the ISO cancelled the startup order. The unit later explained that its startup times would be longer if the other onsite unit was not operating. In an example of a failed start, one oil unit tried for all six days of the July 2013 heat wave to start, and was never able to come online.

Q: Can you provide any examples of situations where these late or failed starts caused system problems?

A: Yes. On June 17, 2013, the system was tight on total thirty-minute operating reserves between 12:00 p.m. and 1:05 p.m., and was intermittently deficient in thirty-minute reserves for a total of 27 minutes during this time. The largest deficiency in this period was 130 MW. Two of the units investigated in this study were late to start during this period. Holding all other activities on the system constant, if these units had performed as expected, the deficiency would have been avoided. The failure of these units to start as requested resulted in a deficiency of operating reserves, leading to the implementation of Master/Local Control Center Procedure No. 2 ("Abnormal Conditions Alert").

C. Outage Rates of Fossil Steam Generators

Q: How are outage rates measured?

A: As part of determining the Installed Capacity Requirement, the ISO's System Planning Department computes an Equivalent Forced Outage Rate – Demand

("EFORd") for most units on the system. EFORd measures the portion of time that a unit is in demand but unavailable as a result of unplanned ("forced") outages. EFORd is expressed as a percentage of hours of unit failure as measured against total hours of availability when needed to serve load; as a result, a lower percentage indicates better performance and is desirable. EFORd values are computed for each FCM commitment period using five years of data from the Generator Availability Data System.

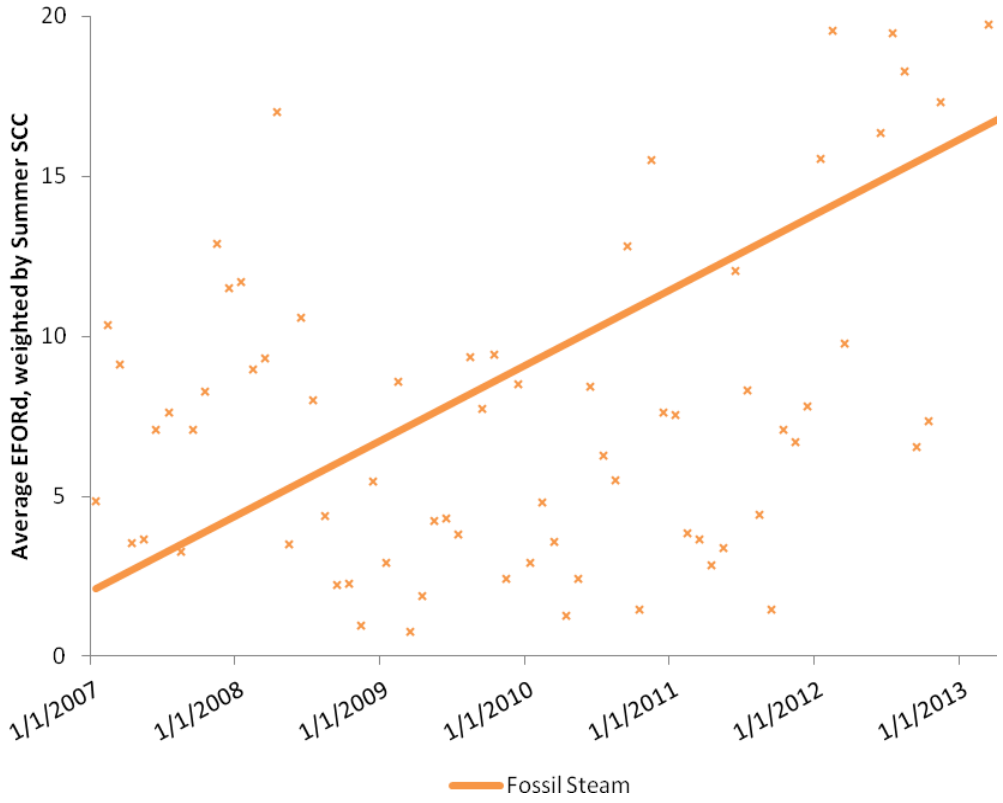
Q: What methodology did you use to review EFORd rates?

A: We studied monthly EFORd rates for those units submitting actual outage data into the Generator Availability Data System. We used the generation categories that correspond with System Planning's reports. These are: hydro; combustion turbines; combined cycle units; internal combustion units, including diesel-fired generators; nuclear; fossil steam; and "other" (including wood- and refuse-fired generators). To determine the outage rates of oil- and coal-fired generators, we reviewed the data for the fossil steam unit category.

Q: What were the EFORd rates of fossil steam units?

A: **Figure 6** includes a linear regression line that shows the EFORd rates of fossil steam units over time. The rest of the chart includes a scatter plot of these units' monthly average EFORd rates.

Figure 6: EFORd Rates of Fossil Steam Units Over Time



Q: Can you interpret these data?

A: The EFORd rates of fossil steam units indicate that, currently, more than 15% of the time when these units are needed, they have an unplanned outage. Moreover, these rates are far higher than they used to be, indicating worsening performance, and exceed the average EFORd rates of the whole fleet (which are discussed below). Despite this poor performance, these resources continue to serve as the region's primary alternative to gas-fired generation by offering capacity in the FCM at prices that clear in the auction.

D. Addressing Oil- and Coal-Fueled Generators' Performance Issues

Q: How could oil and coal units improve their performance?

A: Generators could make incremental investments to maintenance practices and operations that might improve their performance, leading to a decrease in unplanned outages and start times or an increase in ramp rates. It is also possible that, with the implementation of the Pay For Performance changes to the FCM, the region's resource mix could change, with some of the poorer-performing oil- and coal-fueled units replaced by lower-cost, more flexible resources with access to fuel.[19]

V. PERFORMANCE ISSUES THAT SPAN THE ENTIRE FLEET

Q: Are there additional performance issues?

A: Yes, unfortunately. Performance problems are not limited to the issues discussed above regarding gas-fired generators and oil- and coal-fueled generators. As discussed below, we've seen fleet-wide performance issues, as indicated in poor responses to the ISO's instructions following system contingencies, increasing

[19] See p. 5 of the Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives at http://www.iso-ne.com/key_projects/fcm_perf_incentives/index.html.

EFORd rates, inadequate staffing of units, and the failure of oil units to maintain fuel inventories.

A. Performance Issues Following System Contingencies

Q: Is there an issue with the performance of units providing reserves?

A: Yes. ISO system operators have observed issues with units underperforming in response to contingency dispatch instructions. One such episode occurred on September 2, 2010, when the ISO violated a NERC Reliability Standard as a result of poor unit response following the loss of the largest contingency.

Q: What happened on September 2, 2010?

A: September 2 was a high load day in New England. After a generation contingency (the largest contingency on the system), emergency dispatch signals were sent to 146 generators, requesting 1,922 MW. Within fifteen minutes of the event, generators had responded with only 1,267 MW. Although operators had requested more MW than necessary to return Area Control Error to pre-disturbance levels, the response was still 174 MW short of the quantity needed. As a result, the ISO violated NERC Reliability Standards.

The September 2, 2010 event led to an internal evaluation of the root causes of this specific event, and the commissioning of the Analysis Group to quantify historical unit performance after contingency dispatch.

Q: What did the analysis group review?

A: The Analysis Group examined unit response rates to contingency dispatch for 36 system contingencies that ranged in size from 500 MW to 1,840 MW and occurred between March, 2009 and February, 2011.[20] In those events, ISO operators requested additional energy from units providing reserves, with requests sent to as few as three and as many as 114 units, asking for total increases ranging from 258 MW to 1,835 MW. The performance of units was measured by computing a response rate for each unit for each contingency event. These response rates were measured as the unit's change in MW output ten minutes after the ISO issued the dispatch instruction in response to the contingency, divided by the change in output requested by the ISO. Response rates were weighted by the size of the requested change.

Q: What were the results?

A: The results of this study indicate that, on average, reserve units failed to provide all of the energy requested by the ISO. In fact, the average weighted response rate was just 71% (65% for online units, 81% for offline units). **Figure 7** shows generator response rates by resource fuel type.

[20] *See* Analysis Group's Analysis of Reserve Resources: Activation Response following Contingency Events at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

Figure 7: Generator Response to Contingencies by Fuel Type

Fuel Type	Requests	Units Requested	ΔDDP[21]	Avg MW/Req	Mean 10 min weighted response rate
Coal	57	11	808	14	57%
Distillate Fuel Oil	64	41	968	15	59%
Jet Fuel	11	10	258	23	67%
Kerosene	9	8	213	24	75%
Natural Gas	143	28	5,860	41	59%
Natural Gas and Distillate Fuel Oil	62	18	1,347	22	53%
Residual Fuel Oil	20	10	474	24	65%
Water	85	31	8,703	102	84%

Q: What are the implications of these results?

A: The analysis indicates that, on average, units do not deliver all of the energy requested by ISO operators after a contingency. These results imply that many of the MW of reserves counted toward meeting reserve requirements may not truly exist when they are requested to be converted to energy; as a result of this analysis, the ISO has taken steps to increase the amount of reserves procured and

[21] "Change in Desired Dispatch Point."

to make other changes in the reserve markets. Importantly, the data also indicates that these performance problems are not unique to any fuel type. Rather, nearly every segment of the fleet – including the non-gas fast-start units relied upon to provide reserves – is failing to perform in accordance with its stated capability.

B. Increasing EFORd Rates

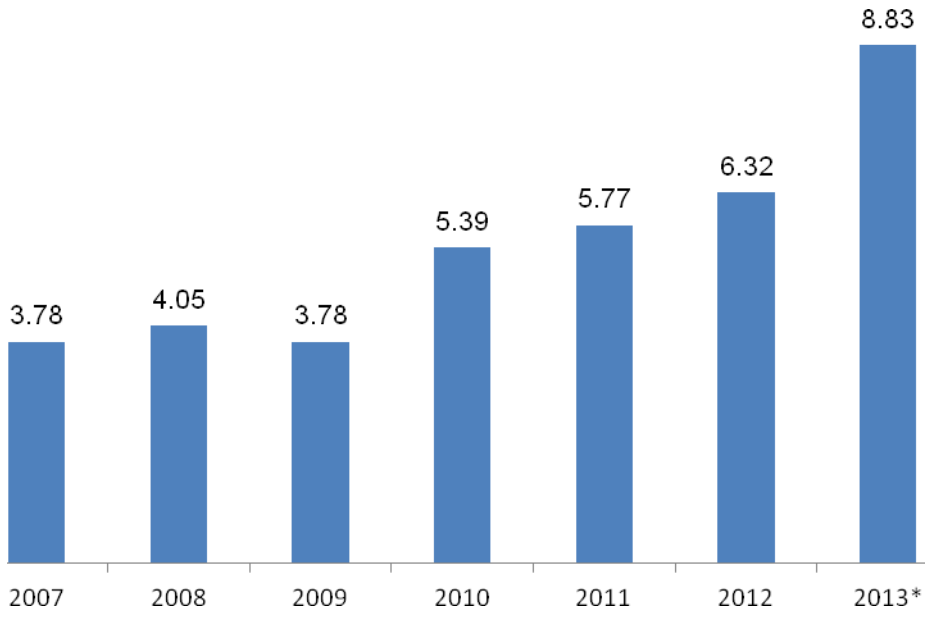
Q: Do fleet-wide outage rates indicate a problem?

A: Yes. As discussed above, EFORd values, which measure unplanned unavailability when generators are needed to serve load, are increasing fleet-wide. Increasing unplanned outages of generators can make it more difficult to operate the system reliably.

Q: Did you confirm and quantify the problem?

A: Yes. We looked at annual EFORd values for generators for the years 2006-2013, and confirmed that the average EFORd is rising. **Figure 8** displays the average annual EFORd values weighted by summer Seasonal Claimed Capability. Note that, although the values provided for 2013 include data only for the months January through August, the year-over-year increase is dramatic, as is the overall increase in EFORd rates, which are 2.33 times higher than they were in 2007.

Figure 8: Annual EFORd Rates



Q: Were you able to analyze EFORd rates by unit type?

A: Yes. We studied monthly EFORd rates for units submitting outage data into the Generator Availability Data System.[22] We grouped generators into technology categories in line with those used in the Installed Capacity Requirement reports. **Figure 9** shows the relative size of each technology category for those units considered in this analysis, and the GW represented by each. **Figure 10** is a scatter plot of monthly average EFORd rates by generation type, with linear regression lines to indicate how the EFORd of each generation type is trending over time.

[22] We excluded the relatively few MW of generation that submitted NERC class average data instead of actual outage data.

Figure 9: Relative Size of Generation Technology Types (Numbers are GW)

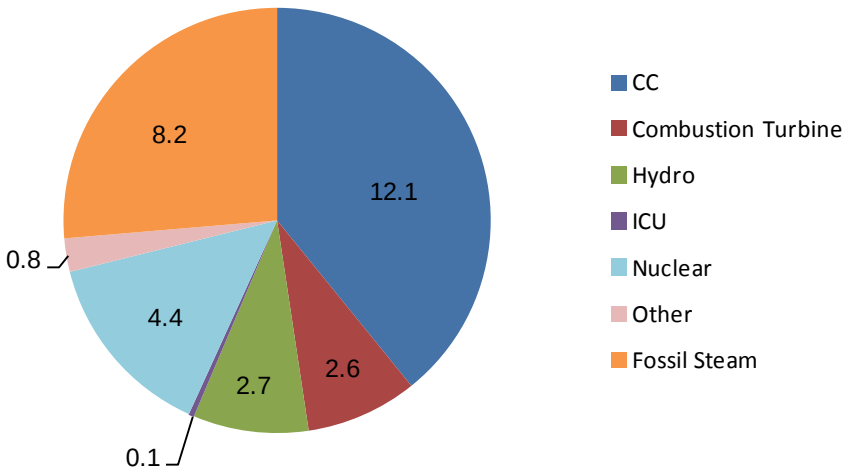
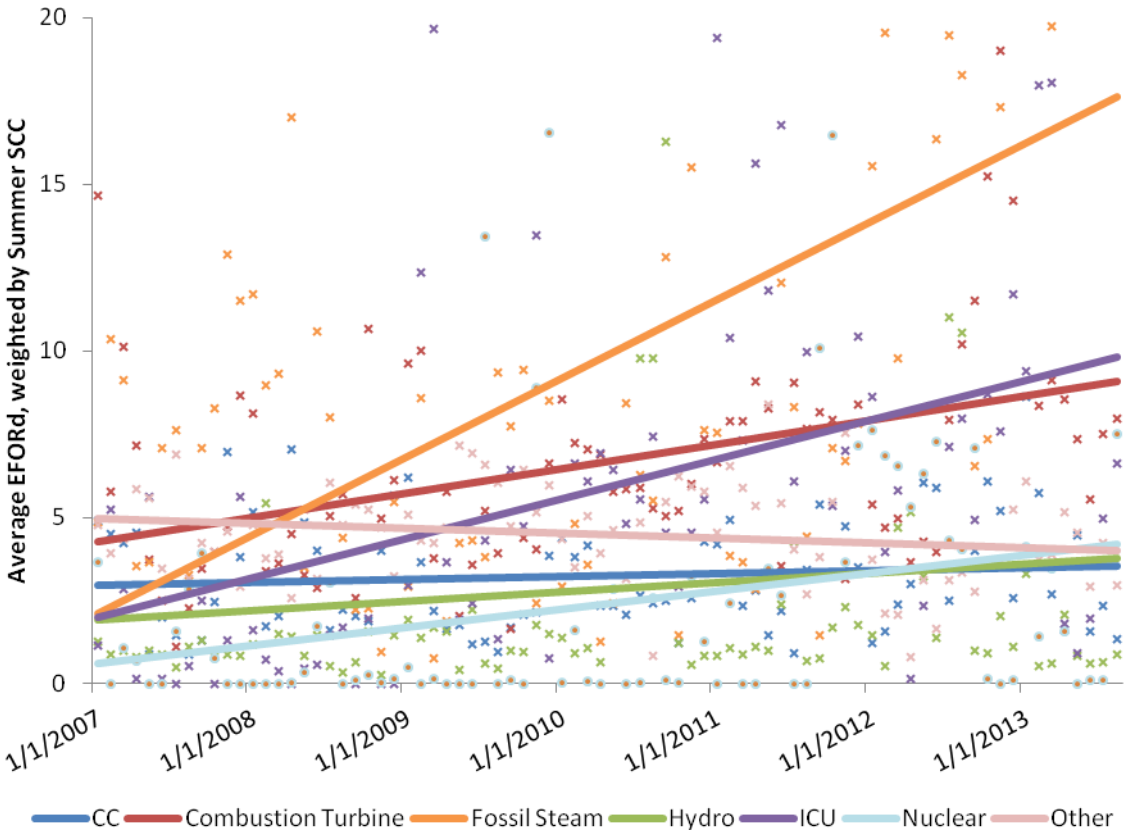


Figure 10: Average EFORd by Technology Type 2007-2013



Q: What is the significance of the analysis of EFORd by unit type?

A: Unavailability is trending upward in all categories except "other," and especially in the fossil steam category, as discussed above. Notably, the analysis also shows that the combustion turbine category has deteriorating availability. This category includes units fueled by oil, kerosene, jet fuel, and natural gas, and represents a large portion of New England's fast-start generation. We are also seeing deteriorating availability with the internal combustion units, which include diesel-fired peaking units that operate infrequently. Increasing outages among these combustion turbine and peaking units are of particular concern because we rely on these units to ensure reliable operations during stressed system conditions, whether to meet summer peak demand or to respond rapidly to system contingencies that can occur any time of the year.

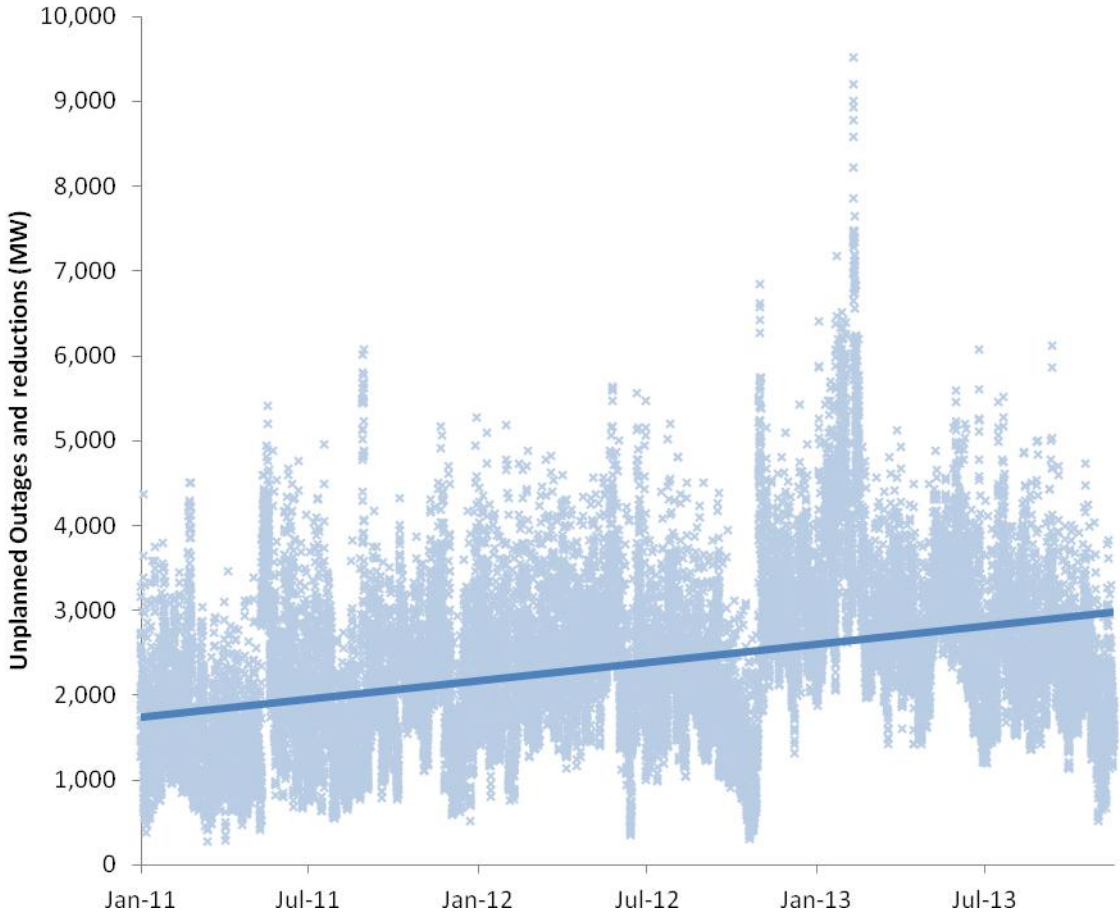
Q: Have you confirmed the EFORd data using other methodologies?

A: Yes. Increasing EFORd rates imply that the amount of capacity that is unavailable is increasing over time. To investigate further, we reviewed alternate data sources, including the ISO System Capacity Monitor ("CAPSYS") and the Control Room Operations Window ("CROW"). CAPSYS is a control room tool used by operators. Among its many functions, CAPSYS computes the net MW effect of current outages and unit reductions in reference to Capacity Supply Obligation for the ISO system as a whole. CROW is an internal ISO database in which detailed generation outage information is logged. CROW went into

production at the very end of 2010, so the data we show in this analysis spans January 2011 through November 2013.

For this analysis, we captured hourly outages and reductions from CAPSYS. We then reduced these hourly quantities by any planned generation outages and reductions logged in CROW. The result is a quantity of MW that the ISO had not expected to be unavailable in each hour. **Figure 11** below shows these hourly values over time. The linear trendline clearly demonstrates that the amount of MW forced offline and reduced from Capacity Supply Obligation levels is increasing over time.

Figure 11: Generator Unavailability Using CAPSYS and CROW



Q: What impact does the increasing frequency of outages have on reserve deficiencies?

A: Between January 2011 and November 2013, there were 78 hours in which there was a deficiency of either total ten minute reserves or total operating reserves (as measured by Energy Management System reserve requirements and designations) for some duration during the hour. In short, had generators with unplanned outages instead performed, they could have, in some cases, ameliorated or even eliminated reserve deficiencies.

Q: Can you give an example where outages led to a reserve deficiency?

A: Yes. July 19, 2013 was the sixth day of a heat wave during which temperatures exceeded 90°F on a daily basis in New England, with temperatures reaching 99°F in Boston on the 19th. The extended nature of the heat wave led to many generator reductions due to ambient air temperature and environmental issues. The load in the peak hour from 4:00 to 5:00 p.m. was 27,377 MW, which is the fourth highest peak load in ISO history. In this hour, 4,265 MW of generation (13% of the total Capacity Supply Obligation for the month) was unavailable as a result of unplanned outages or reductions.[23] Outages and reductions on this day resulted in an extended deficiency of operating reserves, which spanned six hours and peaked at around 700 MW of deficiency. ISO operators were required to implement Operating Procedure No. 4 ("Action During a Capacity Deficiency").

C. Failure to Appropriately Staff Generators

Q: Please discuss the issue with inadequate staffing.

A: The failure to adequately staff generators has, in some instances, prevented generators from coming online when dispatched by the control room. For example, on July 26, 2012, the control room attempted to dispatch a generator that had operated on the prior day but did not have a day-ahead schedule for the 26th. The generator failed to start, indicating that it did not have staff on hand to

[23] Another 346 MW were unavailable as a result of planned outages, totaling 4,611 out-of-service.

operate the facility. When asked why staff was not available, the generator explained that it did not staff the plant full-time; because the generator ran infrequently, it maintained only a single, on-call skeleton crew. That crew had been called to operate the plant on the previous day and was not available for the current day.

In another instance in August, 2012, the ISO attempted to bring a generator online in accordance with the generator's offer. A security guard answered the phone and reported that he was the only person onsite and he had no contact information with which to summon anyone else to the plant. (The generator ultimately made a self-report to the NPCC regarding the incident.) In two instances in the summer of 2012, a generator reported that it had "exhausted all staffing options" and was therefore unavailable.

Q: Why are generators not appropriately staffing their units?

A: In my opinion, generators take the chance that they won't be called and make an economic decision to cut costs by sending staff home. Quite simply, they do not have adequate incentives to keep their units fully staffed and ready to operate.

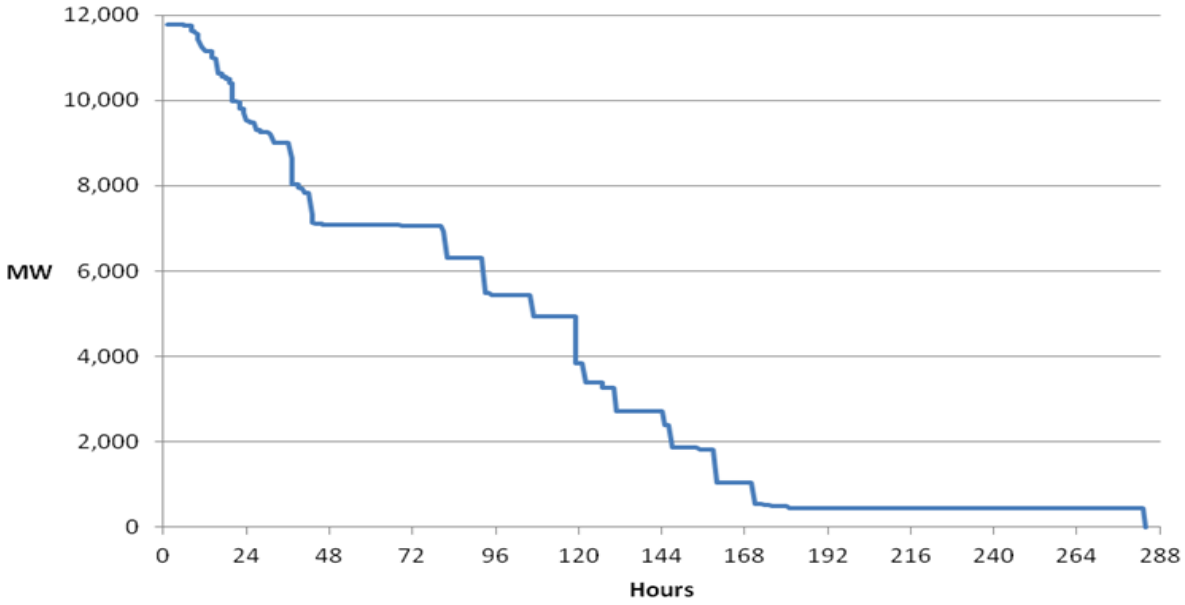
D. Low Oil Inventories

Q: Please describe oil units' inventory practices.

A: As noted above, the ISO has been enhancing its information-gathering on the topic of fuel inventories. By surveying resource operators, we know that oil and dual-fuel units have tanks that are kept, on average, only about one-third full. This may be adequate for the limited hours that oil units are dispatched during the year (oil-fired resources make up less than 1% of the electricity generated annually), but it limits the availability of these resources when needed for sustained periods. For example, if the nearly 12,000 MW of resources capable of operating on oil were operated at full load, based on their reported inventories almost half of those resources would become unavailable within a few days, assuming no replenishment of fuel. See **Figure 12** regarding estimated oil-generator output, which is based on information from generator fuel surveys.[24]

[24] For more information, *see* pp. 5-6 of Winter Operations Summary: January – February 2013 at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

Figure 12: Estimated Oil-Fired Generator Output Based on Reported Fuel Inventories



Q: Can you give an example of a generator failing to operate because of insufficient oil?

A: Yes. One oil-fired unit has repeatedly failed to produce at times of system stress. In February, 2013, during Storm Nemo, the unit offered in at a high price to avoid being committed and alternatively represented itself as unavailable, while later confirming that it was out of oil. In July of 2013, during a heat wave, the unit asked the ISO to reduce the unit's output "for environmental reasons," and later noted that its oil tanks were getting low. During the heat wave, the ISO contacted the unit every two hours to monitor its oil inventory and kept the generator at its Emergency Minimum Limit. The unit would have been dispatched at higher levels if it had fuel. Notably, despite the unit's report of its minimal fuel

inventory, the unit offered itself as fully available in the markets throughout the heat wave.

Q: What actions has the ISO taken to mitigate the risks created by low oil inventories?

A: As discussed above, during the 2012-2013 winter, the ISO learned that oil units were not keeping sufficient fuel on hand and gas units were having difficulty procuring gas. We grew concerned about operational difficulties in the upcoming winter (2013-2014). Ultimately, because the Pay For Performance changes and other market improvements would not be in place in time, we proposed a stop-gap "Winter Reliability Program" that, among other things, compensates oil-fired and dual fuel units for keeping oil in inventory. This is an out-of-market solution that was deemed necessary to ensure reliable operations in the event of a cold snap or other contingency. While it is too early to assess the Program's impact, my belief is that it will have proven to be critical to reliability this winter.

Q: Isn't this issue resolved by the Commission's order on the complaint filed by NEPGA on the topic of generator obligations?

A: I believe it is. The ISO interprets the Commission's order as requiring oil resources to have sufficient fuel in their tanks to meet their Capacity Supply

Obligations.[25] However, as discussed further below, these examples are included to illustrate that generators' existing incentives are leading them to make decisions that are consistent with their economic self-interest but do not facilitate regional reliability.

E. Observations

Q: Are there any commonalities among these performance issues?

A: Yes. There are two. First, a number of these performance issues indicate that the ISO is not receiving accurate information from generators about their resources' ability to operate. This is evident in cases where generators do not have gas or oil to operate, despite having offered into the markets. As we saw with oil and coal units, it is also clear that some generators' start and notification times may not be accurate. Finally, units are representing themselves as available when they do not have staff on hand to operate.

System operations – both operator actions and system dispatch software – are predicated on the ability to rely on the market and capability data submitted by resources. In general, these data have become less reliable, as detailed in my testimony. During times of system stress, the data become even more suspect.

[25] *See New England Power Generators Association, Inc. v. ISO New England Inc*., 144 FERC 61,157 (2013).

This requires the system to be operated conservatively where possible, increasing costs and distorting market outcomes, which further blunts the price signals sent to the market in response to problems. Where it is not possible to operate the system conservatively, we must live with the heightened risk of reliability problems.

Second, it is clear that many of the generators' actions – whether failure to keep oil in the tank or to staff their units – are consistent with their economic self-interest but are not aligned with regional reliability. In another example of this behavior, a number of generators regularly modify their start and notification times when they do not receive a day-ahead commitment. In fact, as recently as December 17, 2013, a fast-start unit changed its operating parameters to include a six-hour start time when in reality it is a ten-minute unit, and, on January 8, four fast-start units changed their start times to 90 minutes. Whether these changes are justified by a lack of staff at the plants or difficulty in getting fuel on short notice, the point is the same; unlike in the current paradigm, generators must have incentives that cause them to take actions that contribute to, rather than detract from, the reliability of the bulk power system.

VI. CONCLUSION

Q: How would you characterize the performance issues discussed above?

A: I would characterize them as pervasive. My testimony has shown that the problems are evident in each significant category of generation. Specifically, gas-fired generators are not procuring firm pipeline access to natural gas, of which there is simply not enough to supply both generators and the LDCs. These generators have limited access to alternatives like LNG. Although the ISO's system operators are actively managing these issues, we have seen some sudden, sizeable reductions in generators' output as a result of gas supply interruptions.

The oil and coal generators we rely on when gas-fired generators are unavailable have their own set of problems. They are the biggest contributors to underperformance relative to their Capacity Supply Obligations, reducing their ecomax during peak hours on peak days more than any other category of generator. They have trouble starting on time (or at all), and their rate of unplanned outages is the highest among the fleet, such that they are unavailable on an unplanned basis more than 15% of the time that they are needed.

While gas, oil and coal units are significant proportions of the fleet, they are not alone in experiencing performance problems. These problems are truly fleet-wide. When we have asked generators to respond to a contingency, the average

response rate is only 71%. Nearly every category of generator is experiencing increasing rates of unplanned outages, with the overall rate more than doubling since 2007. Generators of different types are failing to staff their units and, as a result, are unable to respond in a contingency. Absent out-of-market action, oil units are keeping their fuel tanks only about one-third full, and dual fuel units are mothballing their ability to switch fuels.

Q: Do these pervasive performance issues need to be addressed?

A: I believe that they do. Even if the region's gas supply problems were solved, we have a system that is dependent on gas and will be vulnerable to gas supply interruptions. This "systemic risk" may be realized in the event of one of a number of pipeline problems, which include maintenance, pressure problems, fuel quality problems, or operational flow orders during periods of high demand. During one of these events, multiple units that simultaneously draw from the pipeline could be affected, causing a correlated outage of multiple generators (including reserves). The scope of the potential problem is illustrated by the fact that a single pipeline can supply generators representing thousands of megawatts of electricity. In other words, given the systemic risk, all generators need to perform.

Q: How would these pervasive performance issues be addressed?

A: Gas-fired generators could invest in sufficient firm gas and/or back-up LNG. Generators of various types could invest in, maintain and test dual fuel capability

and keep their alternate fuels on hand. They could also adjust maintenance practices and operations. Ultimately, the region will need investment in new resources and we will need those resources to operate reliably. With the recent announcement of generator retirements, we are reaching that point now and the market needs to work to incent investment in the resources the region needs. These decisions are the generators' prerogative. The ISO's role, and that of the markets we administer, is to give these generators the appropriate incentives to ensure that decisions are made that are both profitable and conducive to the reliable operation of the bulk power system.

Q: Does this conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.

Peter Brandien

Vice President – System Operations

Attachment I-1c

Testimony of Matthew White on behalf of the ISO

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF

MATTHEW WHITE

ON BEHALF OF ISO NEW ENGLAND INC.

Filed on: January 17, 2014

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

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

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Matthew White. I am the Chief Economist for ISO New England Inc. (the "ISO"), One Sullivan Road, Holyoke, Massachusetts 01040-2841

Q: Please describe your responsibilities, work experience, and educational background.

A: My primary responsibilities at the ISO include the design and development of the ISO's suite of auction-based electricity markets. Prior to joining the ISO, I held faculty appointments at the University of Pennsylvania's Wharton School of Finance and Commerce (2002-2009) and Stanford University's Graduate School of Business (1995-2001). At these institutions I conducted research on electricity demand, pricing, and market design, and taught graduate-level courses in economics and decision analysis. My public service includes appointments as a senior staff economist at the Federal Energy Regulatory Commission, Office of Energy Policy and Innovation (2009-2010) and the Federal Trade Commission,

Bureau of Economics (2001-2002). My research studies have been published in peer-reviewed economics journals, and I have served as a referee and evaluator for the National Science Foundation and over twenty-five journals spanning economics, engineering, and political science. I received a M.S. in Statistics and a Ph.D. in Economics from the University of California, Berkeley.

II. PURPOSE AND ORGANIZATION OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to explain in detail the rationale for and the design of the Pay For Performance reforms to the Forward Capacity Market ("FCM").

Q: How is your testimony organized?

A: In Section III, I explain the economic rationale for improving resource performance incentives, and why stronger market-based incentives are essential to solve the reliability challenges facing the New England system today. I show that the current FCM design has a number of significant flaws that undermine performance incentives and that must be fixed. I also explain how a well-designed capacity market remedies these flaws, and that changes to the energy market alone will not.

In Section IV, I explain how the Pay For Performance design works. In particular, I show that Pay For Performance is simply a two-settlement system for forward capacity market obligations. I explain how this improvement satisfies economically-sound market design principles, which in key respects the current FCM does not. This section emphasizes the close connection between a resource's performance during periods of scarcity and its market compensation, a hallmark of well-designed markets.

In Section V, I provide a detailed explanation the Capacity Performance Payment[1] Rate, an important value in the design that corrects the FCM's price signal for resource investment and performance. I start from two simple economic principles, and derive an appropriate performance incentive rate that is consistent with the goals of the capacity market.

In Section VI, I show that with the Pay For Performance design, the Forward Capacity Auction selects a more reliable mix of capacity resources for the power system. I demonstrate how the FCM selects capacity resources cost-effectively under the Pay For Performance design, and I explain why the FCM does not select resource's cost-effectively under current rules. Moreover, with these

[1] Capitalized terms used but not otherwise defined in this testimony 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, or the Pay For Performance rules.

improvements there is less volatility than would occur if similar incentives were included in the energy market instead.

In Section VII, I enumerate and explain other important features of the Pay For Performance design. This includes the economic rationale for a number of detailed design elements, including Capacity Scarcity Conditions, the Capacity Balancing Ratio, and Capacity Performance Bilateral transactions.

In Section VIII, I describe the economic logic and the terms of the Pay For Performance "stop-loss" provisions, which will limit the downside consequences for a capacity supplier in the FCM.

III. RATIONALE FOR FCM CHANGES TO IMPROVE PERFORMANCE INCENTIVES

A. The Capacity Market Must Provide Incentives For Resources To Perform To Achieve Its Goals

Q: What are the central goals of New England's capacity market?

A: In New England's restructured electricity system, the capacity market has two central, related goals: (1) to ensure that there are adequate resources – the right amount, in the right locations, and able to perform as expected – to meet the

region's reliability objectives; and (2) to ensure that the first goal is achieved in a cost-effective manner.

Q: Is the ISO seeking to change these goals?

A: No. In implementing Pay For Performance in the FCM, the ISO is not proposing to alter these central goals. Rather, the ISO is proposing to fix existing flaws in the FCM design that hamper the capacity market's ability to achieve these goals.

Q: What do you mean that resources must be able to perform as expected?

A: It is tempting to think that the first goal stated above – adequate resources – is simply about having enough capacity installed in the right locations to serve demand. But the mere existence of those resources, even if ample in quantity and well-located, is meaningless if those resources do not provide energy or reserves. The ISO cannot reliably operate the system if the resources it depends on do not or cannot perform (that is, do not provide energy or reserves) as offered during periods of scarcity. A well-designed capacity market not only induces the existence of sufficient resources in the right locations, it also must play a role in ensuring that those resources are appropriately valued and compensated for the energy and reserves they provide when needed.

Q: What are the region's reliability objectives, and how is actual resource performance related to those objectives?

A: In New England, the reliability planning requirement for resource adequacy is based on system performance. Specifically, ISO New England Planning Procedure No. 3, "Reliability Standards for the New England Area Bulk Power Supply System"[2] Section 2, explains the resource adequacy criterion. It states, in substantive part, that to assure resource adequacy the system will be planned in such a manner that "the probability of disconnecting non-interruptible customers … will be no more than once in ten years."[3] In other words, the resource adequacy objective of the FCM is not defined by a target capacity reserve margin, but rather is defined by a loss-of-load probability standard. This is achieved by having a certain amount of capacity that operates with a certain level of performance.

If the system's resources do not perform adequately during periods of scarcity, the system's actual loss-of-load probability will not satisfy the resource adequacy criterion. So actual resource performance during scarcity conditions, and not just having a certain number of installed megawatts of capacity, is central to achieving the region's reliability objectives.

[2] ISO New England Planning Procedure No. 3 is available at http://www.iso-ne.com/rules_proceds/isone_plan/pp03/pp3_r6_final.pdf

[3] *See id.* at 3.

Q: Does the FCM currently provide incentives for resources to perform during periods of scarcity?

A: The importance of ensuring resource performance during periods of scarcity was well recognized in the original FCM design. Yet, while there are provisions in the current rules that were intended to provide such incentives, they are both too weak and riddled with exemptions that excuse poor performance during scarcity conditions.

To remedy this problem and achieve the FCM's goals, the ISO is replacing the capacity market's flawed performance incentives with a performance incentive design that will compensate resources for investments that contribute to reliability and send price signals for performance during scarcity conditions.

Q: Why is the ISO making these changes at this time?

A: Although the flaws of the FCM's performance incentive mechanism have been present since the capacity market's inception, the practical consequences of these flaws have become significantly greater during the last few years.

As the testimony of ISO witness Brandien describes in detail, the New England power system faces significant and growing reliability risks. These include, in brief:[4]

- System operators' concern that the regions' gas-fired generating units, which rely on a frequently constrained, "just-in-time" pipeline supply system, lack the fuel supply arrangements and backup fuel capabilities necessary to assure they can deliver power during stressed system conditions.

- Growing risks of relying upon the region's existing oil- and coal-fired steam units because these units, as a class, are inflexible and exhibit substantially deteriorating performance and availability.

- Overall system trends in unit outage rates that are getting progressively worse over time, across many generation technology types, rather than improving.

- Recurring events in which a broad array of generation resources performs poorly when requested to deliver additional energy following major system contingencies.

[4] *See* Testimony of Peter Brandien on behalf of the ISO, submitted with this filing as Attachment I-1b ("Brandien Testimony").

As the Brandien testimony indicates, these performance concerns span a wide array of resource types and technologies. They present new levels of reliability risk to the region because many of the underlying risk drivers can force output reductions from multiple generators concurrently, and the system operators are no longer confident that the remaining generators will perform as expected and as offered.

Q: Why is the ISO choosing to address these reliability risks through market incentives?

A: As agreed to by its stakeholders through the Participants Agreement and approved by the Commission, the ISO's mission is to assure the reliability of the region's bulk power system through open markets. In New England, vertical integration has been effectively eliminated and, as a result, only financial incentives can induce resource investment and performance. In light of diminishing performance under current FCM rules, greater financial incentives are needed to resolve these reliability risks. The logic is simple: Reducing these risks will require new investments and capital expenditures by the regions' capacity resource owners to improve the performance of their existing assets, and to develop replacement capacity resources. Private investors will undertake such investments if there is a sufficient financial return in the ISO's markets; they will not undertake them if the market's incentives do not reward investments in improved performance and reliability.

Q: Can you be more specific about the potential investments and capital expenditures that can resolve these risks?

A: The most cost-effective capital expenditures may take many different forms that vary with each resource's technology, location, and individual circumstance. Many types of technologies and contractual arrangements may be technologically feasible to reduce gas supply risks, such as adding and maintaining dual-fuel capability, securing back-up LNG supply, or contracting for firm gas transport. The fact that these may be technologically feasible, however, does not mean they are commercially feasible for generators in the absence of a higher expected financial return on these investments than the ISO's markets currently provide.

Similarly, business practice improvements – such as greater expenditures on maintenance and equipment, or improved facility staffing – may enable a resource to respond more reliably when needed. However, in a competitive market, these expenditures will not be incurred by profit-minded owners unless the return for delivering energy at those times covers the additional investment.

Moreover, entirely different types of capacity resources may help to address these reliability risks as well. Greater amounts of flexible generation, new storage technologies, or fast-responding demand-side resources that reliably deliver energy on short notice can help maintain reliability during stressed system conditions and unforeseen fuel supply disruptions. In some cases, it may simply be the most cost-effective outcome for resources with progressively deteriorating

reliability to retire, and be replaced with new capacity resources that provide reliable performance.

That said, our analysis indicates that only the most ineffectual capacity resources will be incented to retire under Pay For Performance. Many existing fossil-fired plants have low capacity costs and perform well enough during scarcity conditions to cover these costs. Thus, the economic analysis indicates that many can remain in the market. I explain this finding in greater detail in Section VI.A (pages 131-132) of this testimony.

Q: How will the ISO determine how much of each type of resource is needed to resolve these reliability risks cost-effectively?

A: The ISO will not make such determinations. In New England's competitive electricity markets, it is the role of private investors – who must place their own capital at risk – to determine the types of investments that are most cost-effective.

That point is important and fundamental. The ISO is in no position to determine what combination of investment in new resources, versus investment to improve performance and reliability of existing units, will prove to be most cost-effective. Nor can the ISO foresee what innovative developments in, say, storage technologies, contractual arrangements in the gas industry, physical plant performance capabilities, and so forth, will become commercially feasible if investors expect higher potential returns for the reliability benefits of their

investments. Indeed, perhaps more important than any of the specific potential investments noted in connection with this filing, are the potential technologies and investments that may emerge in the future the ISO has *not* yet identified. Put simply, the determination of what specific types and amounts of private investments are best suited to resolving New England's growing reliability risks is the central role for a competitive marketplace, not for the ISO.

In this environment, the capacity market must serve to reward investment decisions that address these reliability risks in cost-effective ways. Accordingly, resolving these reliability risks requires improving suppliers' financial incentives to undertake the investments *they* determine will best improve resources' performance during periods of heightened reliability risk.

Q: How can a capacity market achieve this goal?

A: By providing simple, strong, and direct financial incentives for suppliers to make investments that ensure they can perform during periods of scarcity. These incentives occur naturally in many types of markets, but as I will explain further below, they do not occur naturally in electricity markets. The FCM's current performance incentive mechanism was originally intended to redress this problem, but it is flawed in many ways – and, most importantly, fails to provide incentives for cost-effective investments that will resolve the region's reliability risks.

B. The FCM's Current Link Between Payments And Performance Is Broken

Q: What is the link between payments and performance in the current FCM design?

A: From its inception, the FCM has included provisions intended to motivate resource performance during scarcity conditions, when system reliability is at heightened risk. The current performance incentive provisions take the form of relatively small and infrequent penalties with many exemptions for non-performance, rather than broader performance incentives that provide both risk and reward.

Currently, the FCM measures resource performance during certain types of scarcity conditions called "Shortage Events." At a high level, a resource's performance is assessed based on its "availability" during Shortage Events. Resources that are not "available" during a Shortage Event receive reduced capacity payments.[5]

Q: Please describe the current Shortage Event mechanism in more detail.

A: In the current FCM, capacity payments are primarily determined by the quantity of the resource's Capacity Supply Obligation MW and the price at which that

[5] *See* current Tariff Section III.13.7.1.

Capacity Supply Obligation was assumed. During the Capacity Commitment Period, a resource with a Capacity Supply Obligation has its performance measured during Shortage Events. Stated simply, Shortage Events are scarcity conditions in which the supply of energy and reserves is insufficient to meet the demand for energy and the ISO's real-time reserve requirements for a duration of thirty minutes or more.

Pursuant to the current FCM rules, the ISO computes an "availability score" for each resource with a Capacity Supply Obligation for each Shortage Event. The availability score is the resource's "available" MW, divided by its Capacity Supply Obligation MW. As a general matter, a resource is assessed as being fully available if it is producing energy at the time, or if it self-reports at the time that it is ready to commence startup procedures. In addition, and notwithstanding the logical contradiction in terminology, a resource is treated as fully available if it is not running and cannot startup for a number of possible reasons listed in the Market Rules.

Q: At a high level, in what ways is this current Shortage Event mechanism flawed?

A: With the benefit, now, of years of practical experience with the FCM, it is clear that the linkage between payments and performance is broken. At best, the FCM's Shortage Event mechanism provides weak incentives for resources to undertake investments to improve resource performance. Indeed, in many ways

the current mechanism creates financial *disincentives* for resource owners to incur additional capital expenses that would improve performance and reliability, because those expenses would raise the resource's capacity cost and render it less likely to clear the capacity auction.

In terms of specific design elements, the current Shortage Event mechanism is flawed for two fundamental reasons. The first is that performance assessments are based on a resource's "availability." This is a flawed performance metric that undermines incentives for true resource performance and the investments that enable it. The second is that the FCM has numerous exemptions that remove almost all financial consequences for non-performance. Other important problems with the current Shortage Event mechanism are caps on potential penalties that turn capacity payments into a free option, and a penalty rate that is needlessly complex and too low to be effective. I will discuss each of these problems in turn.

1. Basing Capacity Payments On "Availability" Is Deeply Flawed

Q: Why do you say that availability is a flawed performance metric?

A: The primary problem with "availability" as a performance metric is that it results in resources with very different contributions to system reliability receiving the same capacity payment. That undermines the financial incentives to enhance

resources' capabilities to deliver during scarcity conditions, because the capacity payment is not directly tied to what is delivered during these conditions.

For example, consider unit flexibility – the ability to start or stop on relatively short notice, and to quickly ramp (up or down) to meet changes in demand or cover other supplier's output fluctuations. Suppose that a high operating-cost, inflexible unit delivers nothing during an extended scarcity condition, because it cannot get online in time to help. In contrast, a similarly high-cost but highly flexible unit, which is capable of responding to the scarcity condition, is asked to deliver as much energy (or reserves) as it can to help resolve the emergency. Both resources are treated as "available" and deemed performing under current FCM rules during the scarcity condition, and receive the same capacity payment.

Because both resources receive the same performance measure under current FCM rules, the FCM provides little incentive for suppliers to develop flexible units, or to undertake capital improvements to increase an existing unit's operational flexibility. Developing flexibility can be costly, and the improved service that flexibility enables is not remunerated in the current capacity market.

The general problem is that basing capacity payments on "availability" means that resources with different contributions to system reliability receive the same payment. The contribution to system reliability of a resource that consistently delivers energy and reserves during scarcity conditions is high, and it should be

rewarded accordingly by the market. In contrast, a high-cost, slow-start unit that delivers little energy or reserves during the scarcity conditions contributes little to system reliability. This resource has less value, and should be paid less – regardless of how it scores on an "availability" performance metric.

If the capacity market's compensation to a unit that consistently delivers during scarcity conditions was higher, and the compensation to a unit that does not deliver during scarcity conditions was lower, the market would produce stronger financial incentives to invest in these capabilities. That requires the capacity market to compensate resources based on their true performance during scarcity conditions – delivery of energy and reserves – rather than based on "availability."

At a high level, one way to think about the problem here is to observe that the term "availability" is a something of a misnomer. It does not measure whether a resource is able to deliver energy (or reserves) at times the system needs it most. Instead, it generally indicates whether a resource claims to be able to deliver energy (or reserves) at some *future* point in time, when the system may – or may not – need it. This leads to perverse market outcomes in which resources with very different contributions to system reliability receive the same capacity payment.

Q: What other sorts of investments might a supplier forego as a result of this flaw in measuring performance?

A: Making the same capacity payments to both poor and strong performers during scarcity conditions undermines incentives for suppliers to invest in the capabilities or technologies that are most valuable for delivering energy (or reserves) during scarcity conditions. Backup fuel or dual-fuel capability is another example.

One important operational concern is that a gas-fired unit that has no dual-fuel capability and has made no advance arrangements for fuel may find it difficult to obtain fuel on short notice. The unit may claim it is available even if it is uncertain that it could deliver energy if called. This is most beneficial to resources with high offer prices, as they are the less likely to be running in advance of a scarcity condition occurring, and so the least likely to have their claim of availability tested. An untested claim of availability allows a resource that cannot deliver during scarcity conditions to receive the same capacity payment as a resource that incurs additional capital costs to maintain backup fuel that ensures it can deliver.

More generally, resources that rarely expect to be called to perform during scarcity conditions have limited incentives to spend capital on firm fuel, dual-fuel capability, or other investments that may be needed only a few hours per year. Even if a resource does not have this capability and could not run if asked, it can list itself as available and know that because of its inflexibility or its high energy offer price, its claim of availability is unlikely to be tested – and therefore it is unlikely to be penalized. Hence, it is not an economic business decision for

many suppliers to invest in secure fuel or dual-fuel capability, because the financial benefit (in the form of reduced penalties) under the current FCM design is unlikely to occur, but the financial costs are up front and unavoidable even if the new investment is never used.

Q: Does using availability to measure performance create other problems?

A: Yes. If a resource can receive its full capacity payment without having to provide energy or reserves, then resources that are able to provide energy or reserves during scarcity conditions may actually be harmed by offering to do so. This is because resources that are more likely to be called during scarcity conditions are subject to more frequent potential penalties, under the flawed availability-based design.

For example, consider again two resources with equal operating costs and that differ with respect to unit flexibility. The better-performing resource, precisely because of its flexibility, is likely to be called on by the ISO far more frequently than the inflexible resource. Using round numbers for clarity, assume each resource has the same 10 percent chance of failing to start because of mechanical problems, and that the flexible resource is called to start ten times for each one time the inflexible resource is called during scarcity conditions.

In this situation, the flexible unit has 10 times the likelihood of being penalized, and 10 times the expected cost (in Shortage Event penalties) associated with

accepting a Capacity Supply Obligation. To cover these greater costs, the flexible unit would require a higher offer price in the forward capacity auction. In effect, its flexibility not only reduces its expected profits due to the FCM penalty mechanism, it reduces the resource's expected profit by making it less likely to clear in the forward capacity auction in the first place.

This truly perverse distortion of proper market incentives is an inherent flaw of the current FCM's availability-based performance metric. It constitutes a strong disincentive to build flexible resources of any kind – which are often the most valuable resources to manage an unanticipated period of heighted reliability risk.

Q: But isn't it unfair to older or less flexible resources to expect them to perform in ways that they were not designed for, and to expected them to deliver energy or reserves in scarcity conditions they cannot foresee?

A: No. Resources with long lead times or other limitations may not be able to provide energy or reserves in all scarcity conditions; and they are not asked to do so if their physical capabilities preclude them from being of any use. Rather, the problem is with how they are compensated.

Because of the FCM's flawed availability-based performance metric, these resources receive capacity revenue as if they are contributing to reliability in situations when they are not. Put another way, the ISO's dispatch instructions reflect a resource's capabilities. Resources that aren't capable of much are not

asked to do much. In a well-designed market, resources would be compensated based on what they do. That works in the energy markets, because units are paid for their performance (delivering energy or reserves) in those markets. It is a problem in the capacity market, however, because resources that are not capable of much get paid the same as units that are highly capable. This provides a disincentive for investors to develop units with greater capabilities, particularly if the additional capabilities entail capital costs that must be recovered through higher offer prices in the capacity market.

In this context, greater capabilities cover a broad range of resource attributes and technologies that share the common characteristic of enhancing the ability to provide energy and reserves during scarcity conditions. For example, such resources include higher-cost flexible resources, lower-cost resources that produce energy in essentially all hours, demand-response resources which characteristically perform well when called during scarcity conditions, and storage and new innovative technologies that can respond to scarcity conditions.

Q: Is that the extent of the problems associated with basing capacity payments on availability?

A: No. So far I have focused on the distorted incentives that individual resources face because capacity payments are based on availability. While the problems with respect to individual resources are bad, they are even worse when considering the New England generation fleet as a whole. The reason is that

basing capacity payments on availability instead of actual performance – energy and reserves provided – during scarcity conditions adversely affects the mix of resources that clear in the FCM.

The reasons for this problem are simple to see: The flawed availability-based performance metric makes it profitable for resources to remain in the capacity market that have: (1) low capacity costs, and (2) perform poorly during scarcity conditions (that is, when measured properly, by energy and reserves delivered). Moreover, by remaining in the market, the poorly-performing resources depress capacity prices and displace other potential suppliers with better performing resources that would do more to improve system reliability.

In effect, the current FCM has a structural bias to select less-reliable resources. In economic terms, the current FCM suffers from a phenomenon known as *adverse selection*: it tends to select resources in the capacity auction that have poor performance and poor reliability, because these characteristics enable resources to have lower capacity costs.

At root, this problem occurs because resources' capacity payments are not directly based on their performance during periods when they are needed the most. Put another way, the capacity market tends to select less-reliable resources because it fails to reward them like properly functioning markets do: based on what they deliver.

Q: In practice, does the FCM make capacity payments to resources that have chronically poor performance during scarcity conditions?

A: Yes. Here some statistics are informative. I examined the performance of the region's larger capacity resources (100 MW or more) since the start of the FCM, which covers the period from June 2010 through November 2013. Performance, for purposes of this calculation, is measured by the sum of the energy and reserves provided by a resource in all hours in which the system experienced a reserve deficiency for a portion or all of the hour, as indicated by the system's dispatch and pricing software.

In this analysis, more than a dozen resources, with combined average Capacity Supply Obligations of 4739 MW over this period, stand out. These resources' performance averages only 17 percent of their average Capacity Supply Obligation MW during scarcity conditions. In simple terms, they have delivered relatively little energy or reserves, as compared to their Capacity Supply Obligations, during scarcity conditions over the last three and one half years (since inception of the FCM). The combined average Capacity Supply Obligations of these resources comprises 15 percent of the Net Installed Capacity Requirement for the current (2013/2014) commitment period.

Over this same time period, these resources have received, in total, $674 million in Capacity Payments. On average, that amounts to $7,153 per MWh of energy and reserves provided by this group during scarcity conditions. That payment rate

makes this group of resources very expensive, relative to what they provide during periods of scarcity.

From these statistics I draw the following conclusions. First, the current FCM continues to retain, and compensate, resources that chronically perform poorly during scarcity conditions. This conclusion is also consistent with the facts documented in the Brandien Testimony concerning the deteriorating performance of the region's fossil-steam fleet, in general.[6] Second, these resources potentially displace entry by new resources that would have better performance, and do more to improve reliability, in the capacity market.

2. Exemptions For Non-Performance Are Incompatible With Sound Capacity Market Design

Q: You stated above that the current FCM design includes numerous exemptions that remove almost all financial consequences for non-performance. Please describe these exemptions.

A: The current FCM rules contain a variety of exemptions under which resources that are not able to provide energy or reserves during a Shortage Event are nonetheless deemed fully "available." As a result they are not subject to capacity

[6] Brandien Testimony at 26-36.

payment reductions, despite providing zero contribution to system reliability during the Shortage Event.

For example, a resource that is on a planned outage when a Shortage Event occurs will be deemed available up the MW amount submitted in the outage request.[7] A resource that is not committed due to an outage or derate of certain transmission equipment is considered fully available.[8] And an import capacity resource that is properly offered, but that cannot be delivered because the relevant external interface is constrained, is considered to be fully available.[9] Demand Resources are not subject to the same Shortage Event provisions, but are subject to other limited penalties.[10] Intermittent Power Resources are not subject to the Shortage Event provisions at all.[11] And, as already described, resources that are unable to help alleviate a scarcity condition due to lengthy startup times are considered fully available.[12] The economic effects of these exemptions will tend to distort the mix of capacity resources in undesirable ways, and are contrary to sound capacity market design.

[7] *See* current Tariff Section III.13.7.1.1.4(b).

[8] *See* current Tariff Section III.13.7.1.1.3(f).

[9] *See* current Tariff Section III.13.7.1.2(d).

[10] *See* current Tariff Section III.13.7.1.5.

[11] *See* current Tariff Section III.13.7.1.3.

[12] *See* current Tariff Section III.13.7.1.1.3(c).

Q: Why are exemptions such as these contrary to sound capacity market design?

A: These exemptions break the link between resource performance and capacity payments. They enable resources that do not deliver energy or reserves during scarcity conditions to continue to receive full capacity payments, as if – counter to fact – they had actually contributed to system reliability during the event. This creates poor incentives, of two forms.

First, it undermines the financial reward for undertaking actions or operational-related investments that can improve resource performance during scarcity conditions, such as plant-level changes that might shorten lead times, making secure fuel arrangements or investing in a backup fuel system, or to incur greater expenses to return from planned maintenance outages faster (facing, say, a spring season with hotter-than-anticipated weather). In brief, when an exemption means that a supplier's capacity payment is not directly tied to what is delivered during stressed system conditions, the supplier does not face strong incentives to invest in ways that can improve the resource's ability to deliver during those conditions.

Second, exemptions enable resources with low capacity costs that expect to perform poorly during scarcity conditions (for any reason) to continue to profitably participate in the FCM. When poor performance is excused and exempt from financial consequences, a poorly performing resource does not need to raise its bid price in the capacity auction to account for any expected penalties

– but resources without the exemption do. This skews the bids in the auction in an especially problematic way: It lowers bid prices from resources that expect to perform poorly and to be exempt from the financial consequences for non-performance. As a result, the auction becomes more likely to clear these poor-performing, less-reliable resources.

At bottom, selling capacity becomes an 'empty' obligation when non-performance is exempt from any financial consequence. In the absence of broad, resource-neutral financial consequences for non-performance, it should come as no surprise that the New England system retains capacity resources that exhibit poor performance during stressed system conditions.

Q: But some of these exemptions are for things beyond the resource owner's control. Why should a resource's capacity payments be reduced if it cannot deliver energy or reserves for reasons beyond its control?

A: Markets must allocate risks that arise from circumstances beyond either the buyer or the seller's direct control. In the capacity market, the market design must either place these risks on suppliers or on consumers. While suppliers may argue that some causes of poor resource performance are 'not their fault,' it is incorrect to conclude that consumers – who are even less likely to be at fault for the supplier's non-performance – should bear the non-performance risk.

Moreover, the concept of 'not my fault' becomes difficult to apply in an economically sound manner in markets intended to motivate long-term resource investments. Creating exemptions changes the return to different capital investments, in potentially undesirable ways. A generator exemption for planned maintenance undermines the incentives to accelerate maintenance work. A long startup lead-time exemption reduces the incentive for a new combined cycle developer to use new technologies that enables the unit to come online quickly. Providing a force majeure exemption for lack of pipeline gas supplies lessens the incentives to install dual fuel or other backup fuel arrangements.

A common refrain is that it makes little economic sense for market design to place performance incentives, and therefore performance risk, upon a supplier for risk factors it cannot control. That common refrain is flatly incorrect, and reflects a fundamental misunderstanding of how markets work – and how the capacity market in particular should work. An important role of the capacity market is to award Capacity Supply Obligations to resources that can be expected to contribute to reliability during scarcity conditions. To do so, a well-designed capacity market should lead a supplier to incorporate into its capacity offer price *all factors* that affect its ability to deliver during scarcity conditions, regardless of whether these factors are within or beyond its control. No other entity is better-positioned to price these factors. In this way, the capacity market offer prices serve an essential role as price signals of both a resource's cost *and its reliability*. That property is crucial to efficient market design: It is what ensures that the

capacity market does not award capacity obligations to resources that expect to perform poorly.

Exemptions undermine this central role of prices as signals of resources' future performance and reliability. In a market designed in large part to help the region meet specific reliability objectives, exemptions are particularly damaging to the market's ability to achieve these objectives at least cost. For all of these reasons, exemptions are incompatible with sound capacity market design. They serve to destroy essential incentives, and inappropriately shift costs to those even less able to manage the risk.

3. Caps On Capacity Payment Reductions For Non-Performance Further Erode Performance Incentives

Q: Please describe the caps on availability penalties in the current FCM rules.

A: Presently, penalties are capped so a resource cannot lose money in the FCM.[13] Even if a resource were to accrue significant non-performance penalties during Shortage Events, the total penalties are limited so that they cannot exceed the resource's FCM revenue. That is, there is no way that a resource can lose money

[13] *See* current Tariff Section III.13.7.2.7.1.3.

in the FCM by accepting a Capacity Supply Obligation in the Forward Capacity Auction, and then failing entirely to perform.

Q: Why is that a problem?

A: This property is contrary to how markets for forward-sold goods should work. A resource that sells a good or service forward, that is, in advance of when delivery is required, takes on an obligation to deliver it. If the seller's cost of making good on delivery exceeds the forward price at which it sold the good, the seller must still make good on the delivery – or compensate the buyer for (the financial equivalent of) the damages it suffers as a result.

The potential for the seller to lose money in making good on its obligation serves two important economic purposes: (1) It motivates only reliable sellers to take on the obligation, and (2) it motivates sellers that do take on the obligation to fulfill it, up to the point where the cost of doing so exceeds the buyer's harm from default. That is how proper markets work, and it is a central property of forward-sold goods markets.

In stark contrast, the "can't lose money" provisions in the current FCM break this basic precept of forward markets. They effectively mean that poorly performing resources are not taking on a proper forward obligation. Rather, they are playing a game of "heads I win, tails I don't lose" with consumers' capacity payments. The "heads I win" scenario corresponds to a year in which the resource, say, is

not called during scarcity conditions, or manages to perform, or fails to perform but is exempt from any penalties; and, in any of these circumstances, has sufficiently small penalties that it has positive net capacity payments for the year. The "tails I don't lose" scenario is one in which poor performance is chronic and not excused, resulting in substantial penalties. In that scenario, the resource walks away without losing money in FCM settlement, even in the worst of circumstances.

Economists have a term for this game: It is called a *free option problem.* By clearing in the capacity market, poor performers have the option to keep the capacity money if they are able to perform. But if they do not perform, they end the commitment period no worse off for having taken on the obligation. Providing free options is exceptionally poor market design, because they undermine essential performance incentives. They make it a worthwhile gamble for suppliers who rarely expect to perform to take on obligations because they have nothing to lose. Worse still, the free option problem helps make it profitable for even the poorest performing resources to remain in the capacity market, potentially displacing entry by more reliable resources that would be able to perform when needed.

The free option problem in the current FCM rules must be fixed to achieve two objectives of a well-designed forward capacity market: (1) that only resources that expect to be able to perform during scarcity conditions take on Capacity Supply

Obligations, ensuring that the ISO can expect to obtain reliable service from capacity resources; and (2) that a supplier accepting a Capacity Supply Obligation is motivated to perform during scarcity conditions, even if the cost of doing so turns out to be greater than it anticipated at the time it accepted the obligation. The costs a supplier must be willing to incur should not be unlimited, but the free option problem with the current FCM must be corrected to improve resource performance and assure reliable service.

4. The Penalty Rate In The Current FCM Rules Is Needlessly Complex And Is Too Low To Be Effective

Q: Please describe the penalty rate for non-performance in the current FCM rules.

A: The penalty rate in the current FCM rules has a structure that defies economic logic. Simplifying slightly, the penalty rate during a Shortage Event is based on a formula in the FCM rules that can be interpreted as:[14]

Annualized FCA Payment × *Percent Factor* × *Availability Score*

[14] *See* current Tariff Section III.13.7.2.7.1.2.

In simplified terms, the *Annualized FCA Payment* is what the resource is paid for its capacity for the year (before applying the penalty). As explained earlier in Section III.B.1, the availability score is the resource's "available" MW, divided by its Capacity Supply Obligation MW. The *Percent Factor,* abbreviated PF in the Tariff, is a number equal to 5 percent for Shortage Events of five hours or less, and that increases by 1 percentage point for each additional hour a Shortage Event lasts, with a limit of 10 percentage points for the day.

The penalty rates that result under this rule have an odd structure: They *decrease* the longer is the scarcity condition. Moreover, they decrease quite rapidly. For example, assume a 1 MW resource receives a capacity clearing price of $3 per kW-month, which is indicative of the level of capacity clearing prices in Forward Capacity Auctions to date. If the resource is unavailable (*i.e.*, a score of zero) for a Shortage Event that lasts only one-half hour, its effective penalty rate is $3,600 per MWh. However, if the Shortage Event lasts for two hours, the effective penalty rate falls by 75%, to $900 per MWh. If there is a severe deficiency lasting five hours, the effective penalty rate is lower still, at $360 per MWh.

Generally, scarcity conditions with longer durations can be expected to occur when the system faces more severe challenges meeting system energy and reserve requirements, and longer periods of heightened reliability risk. Under the current FCM penalty structure, however, the penalty rate *falls* significantly the longer the scarcity condition. In effect, as scarcity conditions continue, the price signal for

resources to perform plummets. This perverse property is difficult to reconcile with economic logic.

Q: Is that the only problem with the current penalty structure?

A: No. In addition to its odd structure, the current penalty structure is needlessly complex. That makes the current FCM performance incentives lack transparency. It hampers the ability of investors to gauge whether additional capital expenditures to improve performance during scarcity conditions would be a profitable investment.

For example, even if a resource owner has a reasonably informed view on how many hours, in total, the system may experience Shortage Events each year, that information is not enough to gauge its expected penalty for non-performance. The resource owner must also estimate the particular duration of *each* non-contiguous Shortage Event during the year – likely an impractical task. Moreover, errors in performing this task can result in mis-estimates of the effective penalty rate by a factor of *ten* (for instance, there is a factor of ten change in the penalty rate between $360 per MWh and $3,600 per MWh in my preceding example).

This needless complexity impedes the ability for a resource owner to quantify whether investments that would improve the resource's performance during Shortage Events would yield a positive return, in the form of reduced penalties.

In effect, its complexity undermines the very goals that these performance incentives are intended to serve.

Q: Are there other problems with the penalty rate in the current FCM rules?

A: Yes. Overall, the current Shortage Event penalty rate is generally low, and far too low to mirror the central principle of well-designed capacity market performance incentives. Over a broad range of possible Forward Capacity Auction clearing prices and scarcity condition durations, the effective penalty rate under the current mechanism is on the order of several hundred dollars per MWh. As I explain in detail in Section V of this testimony, to provide appropriate incentives for cost-effective investments, the marginal incentive to perform during scarcity conditions should be larger than this by an order of magnitude.

The low rate that presently applies to non-performance in the FCM directly undermines the financial incentives for resources to undertake capital investments to improve performance during scarcity conditions.

C. There Is A Simple Logic to Well-Designed Capacity Market Performance Incentives

1. How Competitive Markets Provide Incentives for Performance

Q: The performance incentives in the current energy and capacity markets seem quite different. From an economic standpoint, does that make sense?

A: No, it does not. Performance incentives in the energy and in the capacity markets should work similarly and in harmony. In fact, there is a simple logic to how performance incentives are achieved in markets, and it applies to both the ISO's energy and capacity markets. Specifically, during scarcity conditions, a supplier's payments should depend on what it actually delivers at the time. The logic of this simple idea is readily evident by considering how markets other than electricity provide performance incentives during scarcity conditions.

Q: How do markets, other than for electricity, generally provide performance incentives?

A: The essential features of how markets normally provide performance incentives are simplest to explain by looking at two market scenarios. The first of the two scenarios arises when demand is less than the market's total supply. In this situation, the competitive market price will be set at the incremental production cost of the most expensive supplier serving demand. This is the oft-cited property that in a competitive market, price equals marginal cost.

The second scenario occurs when demand reaches the market's supply limit. In this situation, the competitive market-clearing price rises above suppliers' incremental production costs. At such times, the clearing price set in a properly functioning market is based on demand – not on suppliers' incremental costs.

Specifically, the market-clearing price is determined by the value that consumers place upon the last unit produced. At that price, no demand goes un-served: total supply equals the total amount consumers choose to purchase.

This market-clearing process works smoothly in many different settings. For example, think of industries that have both short-run supply constraints and provide a service, or a good that is not easily stored, such as delivered natural gas, hotels, or airline flights. In those industries, when demand reaches the market's short-run supply limit, price rises to what the market will bear. When demand is lower and sellers find they have idle gas transportation capacity, un-booked hotel rooms, or unsold airline tickets, price falls closer to marginal cost.

Q: How does this provide performance incentives?

A: During periods when the market is tight, suppliers earn revenue in excess of their variable costs. In economics parlance, this is called *scarcity revenue* (or sometimes scarcity "rent"). It is revenue that a properly functioning, competitive market provides during scarcity conditions, when demand reaches the market's short-run capacity constraints. Because price falls close to marginal cost during non-scarcity conditions, suppliers in many markets must cover their total costs and earn the return on their investments based on what they deliver during scarcity conditions.

The opportunity to earn scarcity revenue at these times plays two important roles in markets. First, it motivates sellers to pursue investments that ensure they will be able to deliver their goods and services during scarcity conditions. That is, a seller has strong financial incentives to make sure that it can provide as much of its goods or services as possible when supply is tightest. Second, the scarcity revenues are an important determinant of the overall amount of capacity a market installs.

Q: How do businesses respond to these incentives?

A: By making cost-effective investments to assure they can deliver when market conditions are tight. For example, an airline should take all possible cost-effective steps to make sure all of its planes are in service and flying during busy travel seasons. It would make sure that all of its planes have been properly maintained and serviced so that they require no down-time during that peak period. It would likely have forward fuel procurement arrangements in place, and might pay extra to fuel suppliers to guarantee its availability and the delivered price. It might hire additional staff to ensure smooth operations at the point of service, such as gate personnel and baggage handlers. So long as these expenses cost less than the incremental revenue they can be expected to generate, they will be made.

2. Flawed Incentives To Perform In Electricity Markets

Q: How do electricity markets differ from the competitive market model you describe above?

A: Electricity markets generally behave like other markets when supplies are ample, but when supplies are tight, things are different. When electricity demand reaches the energy market's short-run capacity limit, the market price for energy is not determined by the value that consumers place on the last unit produced – it does not rise to the price that the market will bear – as in the other markets that I described above. Instead, it continues to be set based on sellers' offers and the ISO's administrative pricing rules.

Q: Why in times of scarcity is the energy price not set by what the market will bear?

A: Energy market prices do not rise to the price that the market will bear in times of scarcity for a number of reasons, but the root cause is that the demand side of electricity markets remains under-developed. For a host of technological, political, and regulatory reasons, the vast majority of electricity consumers are not exposed to real-time electricity prices. That is, consumers have neither the information (about real-time prices) nor the incentive to reduce their electricity consumption in response to scarcity conditions in the wholesale market. Without a natural demand-side response mechanism by consumers, there is no means for suppliers in the wholesale market to determine what price the market is willing to bear for the limited supply available during scarcity conditions.

Cognizant of this problem, wholesale energy markets such as New England's have alternative mechanisms to set price during scarcity conditions. Specifically, during periods of scarcity the energy market price is determined by the offer price of the marginal supplier, plus an administratively-determined price adder. The adder, which is informally called a scarcity price (and in our Tariff is referred to as a Reserve Constraint Penalty Factor or "RCPF"), helps to replace the energy market's missing scarcity revenue during tight market conditions.

Unfortunately, this scarcity pricing mechanism is not flexible enough to equilibrate electricity supply and electricity demand during scarcity conditions. That is, the energy market's administrative price adders do not – and cannot – adjust the total energy price to ensure no demand goes un-served during scarcity conditions, as naturally occurs in other markets. The ISO cannot do this because it does not have the information this requires (there are insufficient demand-side bids in the Real-Time Energy Market), and because the absence of natural demand-side response by consumers means electricity demand may not react as required.

These shortcomings mean that even with administrative scarcity pricing in the energy market, electricity markets still face a reliability problem and an investment problem.

Q: What is the reliability problem?

Because the energy market cannot adjust price in real-time to equilibrate supply and demand, it cannot assure that no demand will go un-served at the prevailing market price under all circumstances. To limit the frequency with which this occurs, the ISO adheres to an administrative rule that determines, in part, the level of reliability consumers should receive. Reliability, in this context, refers to the chance that (some) demand would go un-served at the prevailing energy market price. In New England, this administrative rule takes the form of the resource adequacy criterion noted earlier in this testimony.

Q: What is the investment problem?

A: The investment problem occurs because the energy market's scarcity revenue is too low to attract the level of investment necessary to achieve the reliability objective. If the scarcity revenue is too low, marginal suppliers will not expect to recover their total costs and will not enter the market (or will soon exit). In that case, additional demand will go un-served, undermining reliability further.

Importantly, the scarcity revenue a seller may earn by producing at these times motivates the seller to do more than just install capacity; it motivates the seller to undertake cost-effective investments to ensure its capacity will perform reliably when demand is high or alternative sources of supply are scarce. Without these investments, the power system will also have poor reliability.

3. The Role Of Capacity Markets

Q: How does the capacity market address this, and how does this relate to performance incentives?

A: At a fundamental level, capacity markets exist to remedy these shortcomings of the energy market. There is no realistic fix to the energy or capacity market that will obviate the need for an administratively-determined reliability criterion, at least for the foreseeable future. A well-designed capacity market can simply and effectively enable suppliers to earn the scarcity revenue that the energy market does not provide and that is necessary to achieve this reliability objective.

However, the capacity market cannot pay out this revenue irrespective of resource performance. Doing so would eliminate the natural mechanism that scarcity revenue provides to guide investments that enable resources to perform reliably during scarcity conditions. Instead, the capacity market must pay out the scarcity revenue that the energy market fails to provide in the same way normal markets do – based on what resources provide during scarcity conditions. If that incentive structure is not replicated, then suppliers will not have the incentive to make the investments necessary to ensure that they are able to perform when needed most – during periods of scarcity.

Q: Does that imply a resource's capacity revenue should depend on its performance during scarcity conditions?

A: Absolutely. In fact, the logic for how a well-designed capacity market provides performance incentives is simple, as it mirrors how markets normally operate. A resource's capacity revenue should depend on the energy and reserves it delivers during scarcity conditions – that is, when there are no additional resources to turn to in order to meet total electricity demand and reserve requirements.

At a high level, this principle works similarly to, and in harmony with, how the energy market provides performance incentives. Suppliers earn the energy market's scarcity revenue during scarcity conditions, and only to the extent they are performing – delivering energy or reserves – at the time. Similarly, suppliers should earn the scarcity revenue that the energy market fails to provide, and that the capacity market is intended to replace, according to the same principle – based on the energy or reserves they deliver at the time.

In this way, the energy and capacity markets jointly provide the strong resource performance incentives that well-designed markets supply. Linking payments to performance is how properly functioning markets work, and rewards cost-effective capital expenditures in assets or capabilities that help ensure resources can perform during scarcity conditions, when reliability is at heightened risk.

Q: What are the hazards of not linking payments to performance in this manner?

A: There are two primary, and related, problems with failing to link capacity payments to performance during scarcity conditions. First, an individual supplier will face the wrong incentives. In many situations, capital investments that improve resource performance during scarcity conditions can cost more than the incremental net energy revenue from the investment. That fact comes as no surprise by itself; because of the demand-side limitations of the energy market, energy market net revenue does not cover all of suppliers' capital investments.

In principle, additional capacity revenue can make the investment profitable. However, this requires the capacity market to recognize, and reward, the resource's improved performance during scarcity conditions. Without strong performance incentives, the capital investment will produce little, if any, additional capacity revenue for the supplier. This provides a disincentive for resources to incur the fixed expenses associated with backup fuel or secure fuel arrangements, or undertake capital improvements that increase resource flexibility, or pursue other capital investments that can materially improve resource performance and system reliability.

Second, without capacity payments strongly linked to performance, a capacity market will have a structural 'bias' to clear less reliable resources. To illustrate why, consider two cases. In the first case, consider a capital expense such as adding backup fuel capability. Capital investments of this sort improve resource performance but can be costly and, in particular, can increase the resource's

capacity cost. To obtain a return on the investment, the resource must raise its bid in the Forward Capacity Auction. That makes the resource less likely to clear. As a result, the capacity market is less likely to select resources that invest in improved reliability.

For the second case, consider now an older resource with declining performance that no longer starts reliably and generates little energy market revenue. By reducing its fixed operations and maintenance expenses the resource becomes less reliable still, but lowers its capacity cost. This enables it to profitably submit a lower bid in the capacity auction – particularly if there is little risk that the resource's capacity payments will be reduced when it fails to perform. Such decisions reduce reliability, but make the resource more likely to clear in the capacity auction. As a result, the capacity market is more likely to select resources that choose not to invest in improved reliability.

Taken together, these two cases imply that a capacity market with poor performance incentives will tend to select less reliable resources. Resources that undertake capital investment to improve performance are less likely to clear, and resources that forego expenses that would improve performance are more likely to clear. Under the current rules, the FCM has a structural bias toward selecting resources that have poor performance and poor reliability, because these characteristics enable them to have lower capacity costs. This structural bias occurs because resources' capacity payments are insensitive to their performance

during periods when they are needed the most. As explained previously, a capacity market with weak performance incentives tends to select less reliable resources precisely because it fails to reward them based on performance during scarcity conditions, as a properly functioning market would.

Q: Do strong capacity market performance incentives remedy this problem?

A: Yes. Linking capacity payments to resource performance during scarcity conditions addresses these problems directly. More reliable, better performing resources can afford to submit lower bids in the capacity auction because of the additional performance-based revenue they obtain, making them more likely to clear in the capacity auction. Less reliable, poorly performing resources cannot afford to submit lower bids in the capacity auction because the reduced capacity payments they receive will no longer cover their capacity costs. This makes poor performers less likely to clear in the capacity auction.

In sum, improving the capacity market's performance incentives will change which resources clear, selecting a better performing, more reliable fleet, rather than being biased toward less reliable resources.

D. The Reliability Problems Actually Observed In New England Are Exactly What You Would Expect As A Result Of The Current Flawed Capacity Market Design

Q: Given all of the problems that you have identified with the current FCM design, what sorts of outcomes would you expect to see after running seven Forward Capacity Auctions?

A: Given the flawed incentives that I have described, and the systematic bias towards clearing less reliable resources in the Forward Capacity Auctions, I would expect to see a deterioration of the reliability of the New England fleet over time, rather than the gradual improvement that would result from sound market design.

Q: In practice, is that what has been observed in New England?

A: Yes. As detailed in the testimony of ISO witness Peter Brandien, the system's resources overall exhibit declining performance by a number of different measures.[15] Moreover, the system's operators no longer have confidence that resources will be able to perform when needed. This uncertain performance is manifest in many different ways and across a broad array of resource types and technologies. Moreover, a portion of the system's capacity resources have exhibited chronically poor performance during scarcity conditions, collecting capacity payments while doing little to assist with reliability during these periods of heightened risk. And it does appear that these problems are getting worse, not better, as time passes.

[15] *See generally*, Brandien Testimony.

Q: Before moving on to explain the Pay For Performance design, please summarize your main points so far.

A: The current FCM provides weak incentives for performance and investment. In a well-designed capacity market, resources would earn the scarcity revenue it provides based on what they deliver during scarcity conditions. The current FCM design does not satisfy this property, and therefore fails to achieve the central objectives of the capacity market. In particular, it provides insufficient incentives for investments that improve resource performance and reliability during scarcity conditions, when the system is at heightened risk. It also results in capacity payments to resources that do little to help meet the system's resource adequacy criterion, which is not a cost-effective use of consumers' capacity payments.

IV. HIGH-LEVEL DESCRIPTION OF THE PAY FOR PERFORMANCE DESIGN

A. Pay For Performance Is Based On Sound Principles For Capacity Market Design

Q: What are the central market design principles of Pay For Performance?

A: The Pay For Performance design adheres to three fundamental market design principles that characterize efficient, competitive markets:

- *Pay for performance.* The first principle is in the design's very name: a well-designed market must pay more for better performance, and pay less for worse performance. This provides the strong performance incentives – at the right times, in the right amounts – that the current FCM lacks.

- *Incentives entail risk.* Second, suppliers – and not consumers – bear the risk and the rewards associated with their resources' performance. This places risk in the right place, in order to incent investment by suppliers and to enable the capacity market's price signal to select a reliable, cost-effective resource portfolio. This risk will need to be priced in each resource's bid in future capacity auctions.

- *Resource neutrality.* Third, the proposal is resource neutral. All suppliers receive the same compensation if they provide the same performance, regardless of their technology.

Q: Please explain the first principle – pay for performance – and how the capacity market must change to incorporate it.

A: The pay for performance principle means that resources that perform well should earn more capacity revenue, and resources that perform poorly should earn less capacity market revenue. By following this principle, the capacity market will incorporate the central features of how properly functioning markets work. Specifically, for all of the reasons discussed above, a resource should earn its

capacity market revenue based on the amount it delivers when demand approaches the market's short-run capacity limit.

To implement this principle, the Pay For Performance design changes the performance-based component of the FCM in two central ways. First, it changes the FCM performance metric to the amount of energy or reserves that a resource delivers. This differs from the FCM's current availability-based performance metric, which is deeply flawed as described previously in Section III.B.1 of this testimony. Second, the capacity market's performance incentive applies during scarcity conditions, which occur when the ISO is unable to satisfy the combined energy demand and operating reserve requirements of the power system. In this way, the design ensures that suppliers face strong financial incentives for investments that enable their resources to perform at the right times and in the right amounts. They are compensated based on what they contribute to system reliability, in the form of energy or reserves, at times when the energy market's incentives are too low and, simultaneously, the system is at heighted reliability risk.

Q: Please explain the second principle – that incentives entail risk – and its consequences for the allocation of risk.

A: A hallmark of competitive markets is that suppliers bear the risk if their assets fail to perform. In the present context, a prominent risk is that if a supplier is frequently unable to deliver during scarcity conditions, it may not be able to cover

its cost and generate a return on its investment. Placing that risk on suppliers is precisely how properly functioning markets work, in order to provide strong financial incentives for resource performance and cost-effective investment.

The Pay For Performance design places resource performance risk on suppliers, which is where that risk belongs. Suppliers are in the best position to manage their performance risk, whether through undertaking new investments to reduce their performance risk, or by making arrangements with other suppliers or entities to cover their obligations during periods they may be unable to perform.

Q: But won't this unfairly penalize suppliers when their non-performance is due to reasons beyond their control?

A: Markets must allocate risks that arise from circumstances beyond either the buyer or the seller's direct control. The costs of those risks must be borne somewhere. In the capacity market, that means that the market design must either place these risks on suppliers, or on consumers. While suppliers may argue that some causes of poor resource performance are 'not their fault,' it is incorrect to conclude that consumers – who are likely much less at fault – should bear the non-performance risk. There is no efficiency gain in doing so.

In fact, markets work best when each supplier bears its own non-performance risks, even when the causes for non-performance are not clearly within the suppliers' control. There are two primary reasons for this. First, the notion of

"fault" and "control" when discussing the reasons for non-performance are rarely black and white. A supplier that decides to mothball its dual-fuel capability becomes more susceptible to being unable to provide energy and reserves if there is a disruption on the gas pipeline network. The pipeline disruption may stem from causes beyond the generator's purview, but the generator' inability to perform is also result of its longer-term decision to not maintain backup fuel capability.

Second, even where the reasons for non-performance are arguably beyond the supplier's control, the capacity market will serve its central goals of achieving reliability cost-effectively when suppliers – not consumers – bear their non-performance risks. By putting the risks of non-performance on the supplier, regardless of the reason, a supplier is incented to incorporate all information it possesses about its expected performance into the offer price at which it is willing to accept a Capacity Supply Obligation. In this way, capacity market offer prices serve an essential role as price signals of both a resource's cost *and its reliability*.

A high offer price signals that a resource either has very high capacity costs, or has a high likelihood of not performing during scarcity conditions, or perhaps both. The capacity auction will not select such a resource if another resource offers a lower price. This proper function of market price signals works only if the market design leads each supplier to incorporate into its offer price its best assessment of all factors that may result in its non-performance – regardless of

whether those factors are within or outside its immediate control. That property is crucial to efficient market design; it is what ensures that the capacity market does not award capacity obligations to resources that expect to perform poorly.

In sum, in a well-designed market, compensation does not depend upon why a supplier is not producing, or whether the reason(s) are within, or beyond, its control. Its performance is a business risk that suppliers must manage, and their entry and exit decisions – and expected capacity market offer prices – should reflect these risks. The Day-Ahead and Real-Time Energy Market designs already honor this central market design principle, in that they provide no excuses, and no exemptions, for non-performance; in those markets, competition and the market design mean the risks of an individual supplier's non-performance are borne by that supplier. A well-designed capacity market must do the same.

Q: Please explain the third principle – resource neutrality – and why it is important.

A: The third important principle of well-designed markets is that two suppliers that provide the same good or service receive the same price. Their compensation is not dependent on whether or not they use the same technology to produce it. The Pay For Performance design honors this principle by providing all resources with the same compensation for the same performance, regardless of resource type or technology. This is important for several reasons. First, it helps to assure that

compensation is non-discriminatory, with payment terms that do not depend in any way upon the class of resource being compensated.

Second, it frees suppliers to identify and develop the most cost-effective means to improve resource performance. There should be no limits on the technologies eligible to receive FCM revenue. This harnesses the full strength of markets to identify new, innovative ways in which current and future suppliers can improve performance and reliability. The span of these cost-effective investments is difficult to foresee, and might include innovative fuel arrangements for intra-regional gas storage with local distribution companies, backup fuel supplies, greater price-responsive demand practices, new energy storage technologies, and so forth. The central point is that the most cost-effective solutions to the region's reliability challenges will surely come from the innovative results of supplier-selected solutions. Providing the same compensation for the same performance enables healthy, strong competition that will reward cost-effective investments as new technologies emerge and the wholesale markets continue to evolve over time.

B. Pay For Performance Is A True Two-Settlement Market Design

Q: What are the characteristics of a two-settlement market design?

A: Two-settlement systems are widely used for forward-sold goods, whether in centralized markets or in bilaterally-arranged forward contracts. They have three principal characteristics:

- *Forward price*. In a two-settlement system, the buyer and seller establish a forward transaction price at the time the buyer accepts the seller's offer. Payment of this forward price represents the first of two financial settlements.
- *Forward position.* In consideration, the seller takes on an obligation that must be satisfied at a future date. This obligation is commonly called a seller's *position* in a forward market. For commodities and other physical goods, this future obligation has three standard elements: The time at which the good is to be delivered; the location at which the good is to be delivered, and the amount to be delivered. Importantly for present purposes, any of these three elements may be specified as contingent upon other conditions, or determined by formula, rather than be specified as a fixed value at the time of the forward sale.
- *Settlement for deviations.* If the time, place, or quantity delivered by the seller deviates from that specified in the contract, the deviation is credited or charged between buyer and seller in accordance with the terms of the forward contract. This is the second of the two financial settlements. When there is a liquid spot market for the forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. In forward-sold goods markets that do not have liquid spot markets at the time of delivery, the settlement price for deviations is stipulated in advance in the forward contract terms.

These three characteristics are the essential 'building-blocks' of well-designed

forward markets.

When organized wholesale energy markets initially emerged, they appropriately developed following these three principles. This is most evident in the design of the Day-Ahead Market, which is a forward market for energy. Specifically, a supplier that clears an energy supply offer in the Day-Ahead Market receives the day-ahead price for the amount of energy it sells forward, which comprises the first settlement. This forward transaction creates a financial obligation for the seller to deliver the amount of energy it sold forward, at a specific location in the network, during a specific hour (or hours) of the next day. If the amount, times, or location of the energy that the seller delivers differ from the terms of the forward transaction, there is a second settlement for the deviation at delivery.

For example, if the supplier delivers more than its forward obligation, it is paid the deviation settlement price for the additional amount it delivers; if the supplier delivers less than its forward obligation, it is charged the same price for the quantity it did not deliver. Importantly, there are no excuses or exemptions associated with the second settlement; the reason a supplier delivers more or less than its forward obligation is independent of the settlement.

Q: What are the benefits of using a two-settlement design for a forward market?

A: The two-settlement market design has numerous virtues. First, it provides a clear product definition. The product transacted in the forward market is an obligation to deliver a particular good at a specific future time and place.

Second, it is conceptually simple. Resources take on a forward obligation to supply at a future point in time, and then cover that obligation either by delivering or through purchases from other suppliers.

Third, the two-settlement design ensures transparency. Everyone knows their obligations, knows the price to be paid if they do not fulfill their obligations, and knows the reward if they are asked and able to deliver above and beyond their obligations.

Fourth, and perhaps most importantly for present purposes, a two-settlement design provides strong performance incentives in both the short-run and in the long-run. It motivates suppliers to take any and all cost-effective investments that will enable them to deliver on their future obligations. It also results in strong incentives for only the most reliable, cost-effective resource to take on obligations in the first place.

Last, a two-settlement system helps to reduce financial risk on both sides of the market. Buyers' expenditures and suppliers' revenues exhibit less volatility over

time using a two-settlement design than if suppliers faced the same performance incentives in a spot market alone.

Q: Is Pay For Performance a true two-settlement market design?

A: Yes. Pay For Performance is a true two-settlement design based on the same logic of forward markets described above. In particular, it has the following three principal characteristics:

- *Forward price*. The Forward Capacity Auction establishes the forward price for Capacity Supply Obligations.
- *Forward position.* A supplier that clears a capacity offer in the Forward Capacity Auction acquires a physical obligation and a forward financial position in the capacity market. Under the Pay For Performance design, a resource's forward financial position is a *share* of the system's energy and reserve requirements in scarcity conditions during the Capacity Commitment Period.
- *Settlement for deviations.* A resource that delivers more or less energy and reserves than its share of the system's energy and reserve requirements during scarcity conditions will receive a performance payment. The performance payment is based on the deviation between a resource's actual performance and its forward financial position. Because deviations can be positive or negative, the performance payment may be positive or negative. The

deviations are credited or charged at a fixed rate specified in the Tariff, called the Capacity Performance Payment Rate.

In this way, a resource's performance is evaluated relative to a pro-rata share of the system's total energy and reserve requirements during scarcity conditions. The settlement for deviations means that resources that perform well, relative to their pro-rata share, will earn more total capacity market revenue. Resources that perform worse than their pro-rata share will earn less capacity market revenue.

These performance payments during scarcity conditions replace the existing FCM Shortage Event penalty structure in its entirety.

Q: You state that under Pay For Performance, the forward position is both a physical obligation and a financial position. Can you please explain that in more detail?

A: Yes. When a resource clears in a Forward Capacity Auction, it assumes a Capacity Supply Obligation for the associated Capacity Commitment Period. As in the current capacity market, the Capacity Supply Obligation represents a physical obligation to offer the MW amount of the Capacity Supply Obligation in both the Day-Ahead Energy Market and the Real-Time Energy Market during the commitment period. Those offer requirements are unchanged under Pay For Performance. A resource's Capacity Base Payment – which represents the first of the two financial settlements – is based on its Capacity Supply Obligation amount and the relevant capacity clearing price.

Under Pay For Performance, a capacity resource's obligations include a forward financial position as well: The financial obligation to cover a pro-rata share of the system's total energy and reserve requirements during scarcity conditions. This financial obligation is covered by delivering energy and reserves, or by purchasing energy and reserves from other suppliers at the time. The purchase from (or sale to) other suppliers is the basis for the second of the two financial settlements, the settlement for deviations. This second settlement for deviation is a resource's Capacity Performance Payment.

Q: Please explain the pro-rata share financial obligation. Can you provide an example?

A: The pro-rata share financial obligation concept is simple, and easily explained by example. When a resource acquires a Capacity Supply Obligation, its share of all capacity obligations is equal to its Capacity Supply Obligation MW divided by the total Capacity Supply Obligation MW of all capacity suppliers. For example, imagine a resource acquires a 300 MW Capacity Supply Obligation, and that the total of all suppliers' Capacity Supply Obligation MW is 30,000 MW. The resource's forward financial position is a 1 percent share of the system's requirements, calculated as 300 Capacity Supply Obligation MW / 30,000 Total MW = 1 percent.

During any period when scarcity conditions occur during the Capacity Commitment Period, the resource's financial obligation is a 1 percent share of the

system's total energy and reserve requirements at the time. For example, suppose a scarcity condition occurs during an off-peak period when the system's total load is 16 GW and the reserve requirement is 2 GW. This gives a total system energy and reserve requirement of 18 GW. The resource's pro-rata share of the system's requirements during this scarcity condition is its 1 percent share applied to the system's requirements of 18 GW. Its pro-rata share is therefore 1 percent × 18 GW = 180 MW.

Q: How does this resource's 180 MW share of the system's requirement relate to its 300 MW Capacity Supply Obligation?

A: At a high level, because the resource has a 300 MW Capacity Supply Obligation, it has an obligation to offer 300 MW into the energy markets. Its Capacity Base Payment – the first of the two financial settlements – is based on its 300 MW Capacity Supply Obligation.

Continuing the example, assume for simplicity that there is only the single scarcity condition described above during the commitment period. The resource's Capacity Performance Payment – the settlement for deviations, the second of the two financial settlements – will be based on its performance relative to 180 MW, which is its pro-rata share of the system's requirements during the scarcity condition. Its Capacity Performance Payment will be positive if the resource delivers more than 180 MW of energy and reserves during the scarcity condition, and its Capacity Performance Payment will be negative if it delivers less than 180

MW of energy and reserves during the scarcity condition. In other words, deviations at delivery are determined by comparing the actual performance of the resource, measured by the energy and reserves it provides, to its share of the system's requirements during the scarcity condition.

Q: Please illustrate the possible outcomes with respect to the Capacity Performance Payments.

A: Assume again only a single scarcity condition event, and that the resource has a 300 MW Capacity Supply Obligation and a 180 MW pro-rata share of the system's requirements at the time of the scarcity condition. Three cases illustrate the possible outcomes. First, imagine that the resource delivers exactly 180 MW of energy and reserves (combined). In that case, its Capacity Performance Payment is zero. The resource's performance exactly matches its share of the system requirements. In this case, there is zero deviation to settle from its forward financial position, and its monthly capacity payment is equal to the Capacity Base Payment.

Now suppose instead that the resource delivers more than its share of the system's requirements. Specifically, suppose the resource performs at its full output of 300 MW. In this case, the first 180 MW that it delivers satisfies its forward financial position. The additional 120 MW of energy or reserves that it delivers above that is a positive deviation from its forward financial position. This will result in a positive Capacity Performance Payment, calculated as 120 MW multiplied by the

Capacity Performance Payment Rate for the duration of the scarcity condition. I discuss the Capacity Performance Payment Rate in detail below.

Last, imagine instead that the resource performs at 100 MW during the scarcity condition – 80 MW less than its share of the system's requirements. In this case, the 80 MW deviation will result in a negative Capacity Performance Payment, calculated as 80 MW multiplied by the Capacity Performance Payment Rate for the duration of the scarcity condition. The Capacity Performance Payment will only be negative if the supplier performs at a level less than the share associated with its obligation.

Q: Doesn't this mean the resource is being penalized for its 80 MW underperformance?

A: No. In the Pay For Performance design, a negative Capacity Performance Payment is in no respect a "penalty." In a two-settlement forward market design, the settlement for deviations, whether positive or negative, is simply the second of the two settlements, as agreed to and understood by the parties upon initiating the transaction (in this case, upon the supplier acquiring a Capacity Supply Obligation).

As a simple analogy, if a grain supplier agreed to deliver ten tons of grain in six months, and then only delivered eight, its under-performance would be settled at the spot price. Even if the spot price happens to be higher than the six-month-ago

forward price, the grain supplier is not being penalized. The transaction is simply being settled as previously agreed.

Pay For Performance, like all two-settlement designs, works the same way. A supplier that under-performs its financial obligation covers its obligation by purchasing from other suppliers, at the agreed upon settlement rate for deviations from forward obligations.

Q: If a resource's Capacity Performance Payment is based on its physical performance, why do you say it is a "financial" position?

A: As with the Day-Ahead Energy Market, under Pay For Performance a resource is not specifically asked, or expected, to physically operate at a MW level equal to its forward position. Rather, it is expected to operate as dispatched. During scarcity conditions, the system dispatch software directs resources to produce at a level that maximizes the sum of the energy and reserves they can provide during each interval, subject to the resource's offered capabilities (such as its ramp rate) and the transmission network's capabilities. A supplier's financial incentives under Pay For Performance – which are to maximize its resource's capabilities to provide energy and reserves – are fully aligned with the system's dispatch objectives to make maximum use of those capabilities during scarcity conditions.

The share-of-system forward financial position, then, is not a physical dispatch target. It is a financial arrangement that links payments to performance, and

thereby creates stronger economic incentives for resources to enhance their capabilities to perform during scarcity conditions.

Q: You stated above that the Day-Ahead Energy Market also follows the principles of sound two-settlement market design. Are there notable differences between the two-settlement design in the Day-Ahead Energy Market and under Pay For Performance in the capacity market?

A: Yes. While both the Day-Ahead Energy Market and the capacity market under Pay For Performance represent true two-settlement designs, there are some notable differences. First, the definitions of the forward positions differ. In the Day-Ahead Energy Market, the forward position is associated with a fixed quantity (for example, a resource might clear 50 MW day-ahead), while in the capacity market under Pay For Performance, the forward position is a percentage share (for example, 1 percent) of the system's requirements, but the MW requirements are not known until the scarcity condition occurs.

Second, the deviation settlement prices in the Day-Ahead Energy Market and the capacity market under Pay For Performance are different. As I stated earlier, when there is a liquid spot market for a forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. The Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions. As there is no spot market for capacity, under Pay For Performance, deviations are settled at an

administratively-determined rate specified in the Tariff. This rate, called the Capacity Performance Payment Rate, plays the role of an additional scarcity price following the economic logic I described earlier in my testimony in Section III.C. I will discuss the Capacity Performance Payment Rate in detail below.

The third notable difference follows directly from the second. In the Day-Ahead Energy Market, the supplier faces uncertainty over the price at which the deviation will settle, because the real-time price is not known beforehand. Under Pay For Performance, the supplier knows in advance the price at which the deviation will settle, because the Capacity Performance Payment Rate is specified in the Tariff.

This eliminates one element of uncertainty. In the energy market, the supplier faces both quantity risk and price risk in the settlement of forward energy positions, while in the capacity market, the supplier will face only quantity risk, as the price will be known.

Q: Who actually pays the Capacity Base Payments and the Capacity Performance Payments to suppliers?

A: Load pays the Capacity Base Payments to suppliers, while the Capacity Performance Payments are purchases by under-performing suppliers from over-performing suppliers. This is an important property of the Pay For Performance design. A resource that performs below its share of the system's requirements is

buying, anonymously and through the pool, energy (or reserves) from resources that perform above their share of the system's requirements at the same time. The price of these transactions through the pool is the Capacity Performance Payment Rate.

Because all of the Capacity Performance Payments are transfers among suppliers, consumers are fully hedged. That is, consumers continue to pay the capacity clearing price determined by the Forward Capacity Auction three years in advance. They are not at risk for unexpectedly high Capacity Performance Payments to suppliers that perform well during scarcity conditions over the course of the Capacity Commitment Period.

Q: Can resources without a Capacity Supply Obligation receive Capacity Performance Payments?

A: Yes. For a resource with a Capacity Supply Obligation, its performance payment is based on the deviation between its actual performance and its share of the system's requirements. For a resource without a Capacity Supply Obligation, its share of the system's requirements is zero. This means any energy or reserves that it delivers during a scarcity condition event is technically a positive deviation from its share of the system requirements, and should be credited – like all positive deviations – at the same Capacity Performance Payment Rate. A resource without a Capacity Supply Obligation cannot under-perform relative to

its share of the system requirements, and so it cannot have negative Capacity Performance Payments.

A useful way to think about the role of a resource that does not have a Capacity Supply Obligation is that it is a counter-party to (one or more) transactions, through the pool, with resources that have Capacity Supply Obligations but are under-performing at the time. For example, suppose that during a scarcity condition, a capacity resource has a negative 10 MW deviation from (that is, under-performs) its share-of-system obligation. At the same time, a non-Capacity Supply Obligation resource over-performs its share-of-system obligation – which is zero – by delivering 10 MW. The resource with the Capacity Supply Obligation will be charged for is negative deviation of 10 MW at the Capacity Performance Payment Rate; the resource without the Capacity Supply Obligation will be credited for its positive deviation of 10 MW at the same rate. In this situation, the resource with the Capacity Supply Obligation is buying, anonymously and through the pool, 10 MW of energy and reserves from the resource without the Capacity Supply Obligation. It is in this respect that a resource that under-performs relative to its share of the system requirement covers its financial forward position with purchases from other suppliers in the pool.

This design feature is important for two reasons. First, it enables Pay For Performance to be a true two-settlement design. Resources with Capacity Supply Obligations cover their forward financial position either with output of their own,

or with purchases from other suppliers. When a resource covers its position with purchases from others, the purchase payment is due to the relevant counterparty regardless of the counterparty's financial position (if any) in the capacity market. In practice, this feature implies that resources without a Capacity Supply Obligation will receive performance credits only to the extent they deliver energy and reserves that help reduce the severity of a reserve deficiency.

The second reason this design feature is important is reliability. It provides strong performance incentives to *all* resources, of whatever type, to deliver energy and reserves during scarcity conditions when system reliability is at heightened risk. During scarcity conditions, the pool of potential resources that might be able to relieve the reserve shortage should be as broad as possible, and from a reliability standpoint there is no reason to limit that pool to resources with Capacity Supply Obligations.

Q: What would happen if there were no scarcity conditions at all during the Capacity Commitment Period?

A: This is unlikely, given how Capacity Scarcity Conditions are defined, as I will explain below. But if there were no scarcity conditions, then each resource would receive its Capacity Base Payments with no performance adjustments up or down. This helps to assure that suppliers would recover the cost of the investments they make to enable improved resource performance in the event that suppliers'

performance, in the aggregate, is so good that when system conditions are tight scarcity conditions do not occur.

In that case, over time, the ISO's Installed Capacity Requirement may fall while still achieving the region's reliability objectives. Thus, a complete absence of scarcity conditions would not be a persistent market outcome.

Moreover, the two-settlement design of Pay For Performance has important risk-reducing properties in additional ways. For example, it provides suppliers with a degree of insurance for a portion of their total revenue (the capacity market revenue) in a year where there are few scarcity conditions due to mild weather or unusually few major system contingencies.

C. How Capacity Performance Payments Are Calculated Under Pay For Performance

Q: Please explain in more detail how a resource's capacity payments are determined under Pay For Performance.

A: As mentioned above, under Pay For Performance, a supplier's FCM revenue comprises two parts: A Capacity Base Payment and a Capacity Performance Payment.

- The Capacity Base Payment is determined by multiplying the resource's Capacity Supply Obligation (in MW) by the relevant prices. For obligations assumed in the Forward Capacity Auction, that price would be the auction clearing price. For obligations assumed in reconfiguration auctions, that price is the reconfiguration auction price. For obligations assumed bilaterally, that price is the bilateral price. This component of the capacity payment is largely the same as under the current FCM rules.[16]

- The Capacity Performance Payment is determined by a resource's actual performance – the MW amount of energy and reserves provided – during scarcity conditions. This component of the capacity payment is different from how the FCM works today, and is the heart of the Pay For Performance mechanism.[17]

I will explain in detail how scarcity conditions are defined later in my testimony, but generally, scarcity conditions occur when total energy and reserves supplied are insufficient to meet the load and reserve requirements, either zonally or system-wide. During a scarcity condition, a resource's performance payment is determined by its Capacity Performance Score. The Capacity Performance Score is a quantity in MW that corresponds to the resource's deviation from its share of

[16] *See* revised Tariff Section III.13.7.1.

[17] *See* revised Tariff Section III.13.7.2.

the system's requirement, as I discussed above. A resource's Capacity Performance Score may be positive or negative, depending on whether the resource provided more or less than its share of the system's requirements during the scarcity condition.

Q: Please explain the calculation of a resource's Capacity Performance Score in more detail.

A: Again, the Capacity Performance Score is simply the MW amount by which a resource over-performs or under-performs relative to its share of the system's requirements at the time of a scarcity condition.[18] A Capacity Performance Score is calculated for each resource, whether or not it has a Capacity Supply Obligation, for each 5-minute interval in which a scarcity condition occurs. The Capacity Performance Score is the difference between the amount of energy and reserves actually provided by the resource during the interval and the resource's share of the system's requirements during that interval, as shown in the following formula:

$$\textit{Capacity Performance Score} = \textit{Actual MW} - (\textit{Balancing Ratio} \times \textit{CSO MW})$$

[18] *See* revised Tariff Section III.13.7.2.4.

The term *Actual MW* simply reflects the average amount of energy and reserves that the resource actually provided during the interval. For example, a resource supplying 100 MW of power continuously for a 5-minute interval, and an additional 50 MW of reserves during the interval, would have an *Actual MW* value of 150 MW. The value *Actual MW* explained here corresponds to a new defined term in the Tariff, Actual Capacity Provided, which I will address in more detail later.

The term *(Balancing Ratio × CSO MW)* reflects the resource's share of the system's requirements, in MW, during the interval. I explained above that a resource's share of the system's requirements is equal to its Capacity Supply Obligation MW divided by the total Capacity Supply Obligation MW of all capacity suppliers. That calculation yields the resource's percentage share of the system's requirements, which would then be multiplied by the amount of those system requirements (measured in MW) to generate the resource's share of the system requirements in MW. The term *(Balancing Ratio × CSO MW)* captures all of these concepts.

The term *CSO MW* in the *(Balancing Ratio × CSO MW)* term is simply the resource's Capacity Supply Obligation. The *Balancing Ratio* term, called the Capacity Balancing Ratio in the Tariff, is the system's total load and reserve requirement at the time of the scarcity condition divided by the total Capacity

Supply Obligation MW of all capacity suppliers. This concept is expressed mathematically as follows:

$$\textit{Capacity Balancing Ratio} = (\textit{Load} + \textit{Reserve Requirement}) \ / \ \textit{Total CSO MW}$$

For instance, suppose a scarcity condition occurs during an off-peak period when load is 16 GW and the reserve requirement is 2 GW. Assume for simplicity that the *Total CSO MW* (total Capacity Supply Obligation MW of all capacity suppliers) is 30 GW. Then the Capacity Balancing Ratio would be (16 + 2) / 30 = 60 percent. As another example, suppose that a scarcity condition occurs during a hot summer day when load is 27 GW and the reserve requirement is 2.4 GW. Then the Capacity Balancing Ratio for that scarcity condition interval would be (27 + 2.4) / 30 = 98 percent.

Q: Please provide an example of how the Capacity Performance Score would be calculated.

A: Assume that the resource has a Capacity Supply Obligation of 300 MW, and that the total Capacity Supply Obligation MW of all capacity suppliers is 30,000 MW. Also assume that the scarcity condition occurs in an off-peak period where load is 16,000 MW and the reserve requirement is 2,000 MW. Assume that during the scarcity condition interval in question, the resource actually provides 200 MW of energy and reserves.

Using the balancing ratio formula above, the Capacity Balancing Ratio for the interval in question is (16,000 + 2,000) / 30,000 = 60 percent.

Using the performance score formula above, the resource's Capacity Performance Score for the interval is 200 MW – (.60 x 300) = +20 MW. Although the resource has a Capacity Supply Obligation of 300 MW, in this interval, by providing 200 MW of energy and reserves, it has over-performed (relative to its share of the system's requirements) by 20 MW. This represents a 20 MW positive deviation from its share of the system's requirements during the interval, and the resource will receive a positive Capacity Performance Payment for the interval of 20 MW multiplied by the five-minute Capacity Performance Payment Rate.

Q: Please provide another example, showing that the Capacity Performance Score can be negative.

A: The performance score will be either positive or negative, as a resource's actual performance may be greater or less than its pro-rata share of the system's requirements during the scarcity interval.

Using all of the same assumptions in the example above, except that in this case, instead of actually providing 200 MW of energy and reserves during the interval, assume that the resource actually provides 150 MW of energy and reserves during the interval.

In this case, the Capacity Balancing Ratio will not change. The Capacity Balancing Ratio for the interval will still be (16,000 + 2,000) / 30,000 = 60 percent.

Again using the performance score formula above, the resource's Capacity Performance Score in this case will be 150 MW – (.60 x 300) = –30 MW. By providing 150 MW of energy and reserves, it has under-performed (relative to its share of the system's requirements) by 30 MW. This represents a 30 MW negative deviation from its share of the system's requirements during the interval, and the resource will receive a negative Capacity Performance Payment for the interval of 30 MW multiplied by the five-minute Capacity Performance Payment Rate.

Q: Does this mean that a resource will receive a Capacity Performance Payment for each five-minute interval?

A: The ISO will only calculate Capacity Performance Scores and Capacity Performance Payments for five-minute intervals in which there is a scarcity condition. But for each interval having a scarcity condition, each resource will get a distinct Capacity Performance Score and an associated Capacity Performance Payment. As stated above, for each five-minute interval having a scarcity condition, the resource's Capacity Performance Payment will be the product of its Capacity Performance Score for the interval and the Capacity Payment Performance Rate. Again, because the Capacity Performance Score may

be positive or negative, the Capacity Performance Payment may also be positive or negative.

From a settlements perspective, capacity payments will be made monthly, and each resource's Monthly Capacity Payment for a month will be the sum of the resource's Capacity Base Payment for the month plus the sum of the resource's Capacity Performance Payments for all five-minute intervals in the month. Again, the sum of the resource's Capacity Performance Payments for the month may be positive or negative. And if the sum of those payments is negative, it is possible they could exceed the Capacity Base Payment, making the resource's Monthly Capacity Payment negative.

The Pay For Performance design does include limits on how negative a resource's net capacity payment can get, in aggregate. These limits are referred to as the monthly and annual "stop-loss" provisions, which I discuss in detail in Section VIII.

Q: Is a resource's average performance during scarcity conditions in a month relevant to the Monthly Capacity Payment calculation?

A: In a sense, yes. As a technical matter, Monthly Capacity Payments will be determined by totaling a resource's Capacity Performance Payment for each five-minute interval in which there is a Capacity Scarcity Condition – without regard to the resource's average performance. However, there is a mathematically

equivalent way to calculate a resource's Monthly Capacity Payment based on average resource performance during scarcity conditions in a month. This exercise is useful because it can help in understanding the Pay For Performance construct, how the capacity market settlements work, and how the stop-loss mechanisms function.

Q: Please explain this alternative approach to calculating a resource's Monthly Capacity Payment based on average performance.

A: This is best accomplished by example. Assume that in a month, several scarcity conditions occur that last, cumulatively, for 18 five-minute intervals. That is a total of 1.5 hours. It does not matter whether some or all of those intervals are consecutive. Assume that over those 18 intervals, the average Capacity Balancing Ratio is 60 percent. Finally, assume that the resource in question has a Capacity Supply Obligation of 300 MW, and over the 18 intervals of scarcity conditions, provides on average 200 MW of energy and reserves.

We can calculate this resource's average Capacity Performance Score using the same formula as described above: *Actual MW – (Balancing Ratio × CSO MW)*. Substituting the values in this example, we get (200 MW – (60% × 300 MW)) = +20 MW. In other words, the resource provided, on average, 20 MW above its share of the system requirements across the scarcity condition intervals in the month.

As in the examples above that only included a single interval, this MW deviation amount must be multiplied by the Capacity Performance Payment Rate to arrive at the Capacity Performance Payment amount for the month. Note, however, that the Capacity Performance Payment Rate is measured in Megawatt-hours. Since in the current example there were 1.5 hours of scarcity conditions, the 20 MW average over-performance amount must be multiplied by 1.5. So the resource's average Capacity Performance Score for the month is 20 MW × 1.5 hours = 30 MWh.

The resource's total Monthly Capacity Payment is its Capacity Base Payment plus its monthly Capacity Performance Payment. This is:

(*FCA Price* × CSO MW) +

(30 MWh *Total Monthly Score* × *Capacity Performance Payment Rate*).

The first term in parenthesis is the Capacity Base Payment. The second term in parenthesis is the monthly Capacity Performance Payment.

To calculate the total Monthly Capacity Payment, we need the *FCA Price* and the Capacity Performance Payment Rate. Both of these values are established prior to the Capacity Commitment Period. For purposes of this example, I will use simple round numbers and assume the FCA Price is $3.00 per kW-month and the

Capacity Performance Payment Rate is $2,000 per MWh. We can then calculate the resource's total monthly payment as follows:

- An *FCA Price* of $3 per kW-month is equivalent to $3,000 per MW-month. The resource's Capacity Base Payment is therefore ($3,000 / MW-month × 300 MW CSO) = $900,000 per month.

- The resource's total monthly performance payment is its total monthly score, 30 MWh in this example, multiplied by the Performance Payment Rate of $2,000 / MWh assumed for this example. This yields a monthly Capacity Performance Payment of (30 MWh × $2,000 / MWh) = $60,000.

On average, this resource performed above its share of the system's requirement during the month's scarcity conditions. Its performance increases its total FCM payment for the month by $60,000, to $960,000.

Q: In what way is this mathematically equivalent to the approach to calculating the resource's Monthly Capacity Payment that you described previously?

A: In the approach I described previously, which is reflected in the Tariff provisions implementing Pay For Performance, a resource's total monthly Capacity Performance Payment will be determined by summing the Capacity Performance Payments for each individual five-minute interval having a scarcity condition, without reference to the average Capacity Balancing Ratio or the average

Capacity Performance Score across those intervals. Using those average values, however, as part of a single calculation for the month, will yield exactly the same value. Again, understanding this will facilitate later discussions about monthly settlements and the stop-loss mechanism.

Q: You stated above that under Pay For Performance, resources without a Capacity Supply Obligation are eligible for positive Capacity Performance Payments if they provide energy or reserves during scarcity conditions. How will Capacity Performance Payments be calculated for such resources?

A: Capacity Performance Payments for resources without a Capacity Supply Obligation will be calculated in the same manner as described above, using the same calculations. Where the resource's Capacity Supply Obligation is used in a formula, a zero will apply.

Such a resource's Capacity Performance Score can only be positive, and will equal its actual performance during the scarcity condition. This is evident by using the value zero for a resource's Capacity Supply Obligation MW value in the Capacity Performance Score formula:

$$\textit{Actual MW} - \textit{(Balancing Ratio} \times \textit{CSO MW)}.$$

Because the Capacity Supply Obligation is zero, there is nothing to subtract from the *Actual MW*, regardless of the value of the Capacity Balancing Ratio. Note,

importantly, that a resource without a Capacity Supply Obligation will have a Capacity Base Payment of zero.

Again, this is an important design feature because it provides strong performance incentives to all resources, of whatever type, regardless of Capacity Supply Obligation, to deliver energy and reserves during scarcity conditions when system reliability is at heightened risk. During scarcity conditions, the pool of potential over-performers that might be able to relieve the shortage should be as broad as possible, and there is no reason to limit that pool to resources having a Capacity Supply Obligation.

D. Capacity Performance Payments Are Transfers Among Suppliers

Q: You stated above that Capacity Performance Payments are transfers of money from under-performing suppliers to over-performing suppliers. Please explain this further.

A: Under the Pay for Performance design, consumers only pay for the Capacity Base Payments, which are fixed at the time of the Forward Capacity Auction. Hence, the costs to consumers are hedged once the Forward Capacity Auction is complete. They do not bear the financial risk of unexpectedly high Capacity Performance Payments earned by suppliers that perform well during the commitment period. Instead, it is the suppliers whose resources perform poorly – below their share of the system's requirements – that bear the risk of covering the

Capacity Performance Payments. During a scarcity condition, some resources will perform well (above their share of the system's requirements) and others will perform poorly (below their share of the system's requirements). The negative Capacity Performance Payments from the latter will go to pay the positive Capacity Performance Payments to the former. Effectively, the FCM performance incentives amount to financial transfers from under-performing to over-performing capacity resources during scarcity conditions.

Q: Please provide an example of how this works.

A: Imagine a two hour scarcity condition event occurs when load and reserve requirements equal 60 percent of the total Capacity Supply Obligation MW – that is, the applicable Capacity Balancing Ratio is 60 percent.

Unit A has a Capacity Supply Obligation of 140 MW. Units B and C each have a Capacity Supply Obligation of 80 MW. During the scarcity condition, Unit A fails to deliver any energy or reserves, so its Actual Capacity Provided is zero. Units B and C each provide a full 80 MW of energy and reserves during the event. Recalling that the Capacity Performance Score formula is *Actual MW – (Balancing Ratio × CSO MW)*:

- Unit A's average Capacity Performance Score is (0 – (.60 x 140)) = – 84 MW.
- Unit B's average Capacity Performance Score is (80 – (.60 x 80)) = +32 MW.
- Unit C's average Capacity Performance Score is (80 – (.60 x 80)) = +32 MW.

For purpose of this example, assume a Capacity Performance Payment Rate of $2,000/MWh, as in prior examples. Then:

- Unit A has a negative Capacity Performance Payment (that is, a charge in the FCM settlement), calculated as: – 84 MW × 2 hours × $2,000/MWh = – $336,000.
- Units B and C each have a positive performance payment (that is, a credit in the FCM settlement), calculated as: 32 MW × 2 hours × $2,000/MWh = +$128,000 each.

The charge of $336,000 to Unit A is used to pay the credits of $128,000 each to Unit B and Unit C. No additional funds are needed or collected from consumers to settle the Capacity Performance Payments to suppliers.

Q: In your example, why is the amount collected from Unit A for its under-performance greater than the total amount paid to Units B and C for their over-performance?

A: In general, there will always be a net surplus when all the performance credits and charges are tabulated. In this example, the net surplus is the difference between total performance charges collected from Unit A and the credits paid to Units B and C is $80,000, calculated as: ($336,000 – ($128,000 + $128,000)).

This net surplus occurs because, by definition, there are more under-performing resources than over-performing resources during a scarcity condition. If there were not more under-performing resources than over-performing resources, then there would not have been a scarcity condition. Stated more precisely, the system experiences a scarcity condition if and only if the total MW of capacity resources performing below their share of the system's requirements exceeds the total MW of capacity resources that are performing above their share of the system's requirements. Logically, if that were not the case, the system's requirements would be met, and there would be no scarcity condition.

In fact, the magnitude of this net surplus is directly related to the magnitude of the reserve deficiency during the scarcity condition. The greater the deficiency, the greater the amount by which under-performing MW will exceed over-performing MW. So long as there are more under-performing MW than over-performing MW (which again, must be the case or there would be no reserve deficiency), and so long as under-performing MW and over-performing MW are charged at the same Capacity Performance Payment Rate, there will be a surplus collected.

At a high level, this over-collection is not unlike what occurs in the Day-Ahead Energy Market as a result of congestion. And it is a useful feature in that it ensures the ISO's revenue adequacy in the pool-wide settlement of all Capacity Performance Payments. That is, the total of all performance-related charges will

always be sufficient to cover the total of all performance-related credits due to others, across the pool.

Q: What will be done with the net surplus?

A: I mentioned earlier, and will describe in detail below, a "stop-loss" mechanism is included in the Pay For Performance design to limit, in extreme cases, the total losses that a supplier might face as a result of negative Capacity Performance Payments. The stop-loss mechanism can be thought of as a mutual insurance plan among suppliers exposed to that risk. The total net surplus resulting from Capacity Performance Payments will be used as a part of that stop-loss insurance mechanism. The stop-loss mechanism is described in detail below, in Section VIII.

V. THE CAPACITY PERFORMANCE PAYMENT RATE

Q: What is the Capacity Performance Payment Rate?

A: As I explained above, Pay For Performance is a two-settlement forward market. In two-settlement systems, when there is a liquid spot market for the forward-sold good, the second settlement price for deviations is typically the spot price, which reflects the cost the buyer incurs due to the seller's non-performance. For example, the Real-Time Energy Market serves this role with respect to Day-Ahead Energy Market positions. As there is no spot market for capacity, under

Pay For Performance, deviations are settled at an administratively-determined rate specified in the Tariff called the Capacity Performance Payment Rate.[19]

A. The Capacity Performance Payment Rate Determines Incentives to Perform

Q: How does the Pay For Performance design improve performance incentives?

A: The primary element is the Capacity Performance Payment Rate. During scarcity conditions, a resource's performance above or below its share of the system's requirements will be settled at the Capacity Performance Payment Rate. As explained earlier in this testimony, the Capacity Performance Payment Rate is the price at which suppliers transact, through the pool, when an under-performing capacity supplier covers its share-of-system obligation with purchases from other suppliers.

Because the Capacity Performance Payment Rate is a price, it affects suppliers' incentives. In real-time, the sum of the Capacity Performance Payment Rate and the Locational Marginal Price comprise a resource's marginal incentive to deliver energy during scarcity conditions. In this sense, the Capacity Performance Payment Rate serves as a 'scarcity price premium' above the real-time energy and reserve prices. It works in addition to, and takes effect under the same conditions as, the ISO's energy scarcity price adder in the Real-Time Energy Market.

[19] *See* revised Tariff Section III.13.7.2.5.

More importantly, the Capacity Performance Payment Rate affects resources' longer-term investment incentives. Over time, resources that perform well during scarcity conditions accrue positive performance payments and greater net FCM revenue. Resources that perform poorly (or not at all) during scarcity conditions earn comparatively less net FCM revenue. Through this mechanism, Pay For Performance creates financial incentives for the system to evolve toward a resource mix that performs well when the power grid experiences operating reserve deficiencies and faces heightened risk to reliability.

Q: What is the value of the Capacity Performance Payment Rate?

A: When fully phased-in, the Capacity Performance Payment Rate will be $5,455 per MWh. I will refer to this value as the "Full PPR" in my testimony. However, this value will not apply upon the initial implementation of Pay For Performance. Instead, the ISO will phase-in the Capacity Performance Payment Rate such that a lower value will apply to upcoming Forward Capacity Auctions, and their corresponding Capacity Commitment Periods, before reaching the Full PPR value. I refer to this period prior to reaching the Full PPR as the "phase-in period." I will discuss the determination of the Full PPR next, and the phase-in period subsequently.

B. The Capacity Performance Payment Rate Is Based On Sound Economic Principles

Q: How did you determine the Full Capacity Performance Payment Rate?

A: I determined the Full PPR value using a three-step process. First, I identified two economic principles to guide the development of the Full PPR. Second, from these two principles I derived a formula that the Full PPR value must satisfy in order to honor the two principles. Third, I used data for the New England system from several sources to calculate a numerical value for the Full PPR, based on the formula derived in step two. I will discuss each of these three steps in turn.

Q: What are the economic principles used to determine the Full PPR?

A: Two specific economic principles guide the determination of the Full PPR. These are:

1. *Entry occurs when needed.* The Full PPR must be set at a level such that a new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement.

2. *Zero revenue for zero performance.* A resource that expects to have zero performance (that is, it expects to supply zero energy and reserves) during all scarcity conditions should expect zero net capacity revenue.

Both of these principles are crucial to a successful capacity market. The first principle requires that when new entry is necessary to satisfy the Installed Capacity Requirement, the *sum* of the prospective entrant's Capacity Base

Payment (determined by the capacity clearing price) and the prospective entrant's expected Capacity Performance Payments is at least as large as the net cost of new entry (also known as "net CONE"). This is essential to ensure that the capacity market serves its objective of attracting new investment in cost-effective resources that can meet the region's reliability requirements.

In this context, the cost of new entry includes, among many things, the cost of permitting, interconnecting, constructing, and financing the new capacity resource. To obtain the 'net' cost of new entry, from the foregoing costs one deducts (the present value of) the net operating revenue the resource expects to earn from its participation in the energy and ancillary service markets. The result – net CONE – represents the costs (including a return on capital) the new entrant must expect to cover from capacity market revenue to be willing to enter the market.

Conceptually, net CONE corresponds to the scarcity revenue that the energy market fails to provide, but that a new entrant would require in order to be willing to invest (when the system requires new entry). The capacity market must remunerate this amount, in expectation, when new capacity is needed to induce investment and satisfy the Installed Capacity Requirement. For present purposes, net CONE does not include any Capacity Performance Payments, which we will describe separately from net CONE for the sake of clarity.

The second principle requires that if a resource's expected performance is zero during scarcity conditions over the entire Capacity Commitment Period, its total expected negative Capacity Performance Payments should fully offset the Capacity Base Payments. In that way, a resource that expects its performance to be zero during all scarcity conditions will not find it profitable to acquire a Capacity Supply Obligation. This principle assures that the region does not pay for, and rely upon, capacity resources that do not expect to perform – at all – during scarcity conditions.

The second principle mirrors, in part, the performance incentives that exist in the energy market: A resource that never provides energy (or reserves) earns zero expected energy market revenue, and would soon exit. Similarly, to provide economically appropriate incentives for such a resource to exit capacity the market, the resource should also expect zero net FCM revenue. A resource that expects to provide zero energy (or reserves) during scarcity conditions is not worth buying in the capacity market.

C. A Simple Capacity Performance Payment Rate Formula Satisfies These Sound Principles

Q: How did you determine a formula that the Full PPR value must satisfy in order to honor these two economic principles?

A: Each of these two economic principles can be represented by precise formulas governing a capacity resource's revenues and costs. I first translated these principles into corresponding formulas. I then combined them logically (which is to say, algebraically) to determine a new formula that the Full PPR must satisfy to honor the two economic principles. Although the final result is a simple formula for the Full PPR, deducing it from the two principles requires many logical steps. I will describe these steps next.

Q: How do you translate the first principle into precise formulas?

A: The first principle – that the Full PPR must be set at a level such that a new capacity resource is willing to enter the market if new entry is needed to satisfy the Installed Capacity Requirement – applies to new entry. In terms of revenues and costs, it is equivalent to stating that a new entrant's expected net FCM revenue must be equal to, or exceed, the sum of its net costs to enter the market and a risk premium (if any) to be willing to accept the obligations that a resource accepts with a Capacity Supply Obligation.

This statement of revenues and costs can be represented more succinctly by the following formula, where all terms are expressed on a per Capacity Supply Obligation MW-year basis:

(A) $$Capacity\ Price_{new} + Expected\ PP_{new} \geq net\ CONE + RF_{new}.$$

I will refer to this formula as Condition (A).

The first term, *Capacity Price*$_{new}$, is the (annual) capacity clearing price when new entry clears. This is also the resource's Capacity Base Payment rate under the Pay For Performance design, represented in dollars per MW-year in this context.

The second term, *Expected PP*$_{new}$, is a new resource's expected (annual) Capacity Performance Payments. It is represented in dollars per MW-year in this context. I explain this term in more detail below.

The third term, *Net CONE*, is the new entrant's (annualized) net cost of new entry, as described earlier. It is represented in dollars per MW-year.

The last term, *RF*$_{new}$, is the new entrant's *risk factor*. The risk factor represents the amount of expected profit, if any, the entrant would be willing to forego by not acquiring a Capacity Supply Obligation and deploying its capital in its next-best alternative use. While it might seem odd for a profit-seeking entity to be willing to forego expected profit, acquiring a Capacity Supply Obligation under Pay For Performance presents the possibility that a resource – if it performs very poorly – could have negative Capacity Performance Payments that exceed its Capacity Base Payments. In that case, it would incur a loss in capacity market settlements. Because of this possibility, a market participant that has positive expected profits from acquiring a Capacity Supply Obligation, but is sufficiently

risk averse, may nonetheless choose to forego those expected profits in order to avoid the possibility that it could incur a loss in capacity market settlements. The risk factor represents the additional premium a new entrant requires, expressed here in dollars per MW-year, above its net cost of new entry, in order to be willing to accept the Capacity Supply Obligation.

To make further use of Condition (A), it is helpful to explain the second term, *Expected* PP_{new}, in more detail. A new resource's *Expected PP* value is determined by the Capacity Performance Payment Rate multiplied by the resource's expected annual average Capacity Performance Score. Stated as a formula, and again with all terms represented on a per Capacity Supply Obligation MW-year basis, this is:

(B) $Expected\ PP_{new} = PPR \times [Actual_{new} - Balancing\ Ratio] \times Scarcity\ Hours_{new}$

I will refer to this formula as Condition (B).

In Condition (B), the terms on the right-hand side of the equal sign have the following precise interpretations:

- The symbol *PPR* represents the Capacity Performance Payment Rate, in dollars per MWh;

- $Actual_{new}$ is the new resource's expected average performance per MW of capacity during scarcity conditions annually (a number normally between zero and one);

- The *Balancing Ratio* as represented here is the expected annual average Capacity Balancing Ratio during all scarcity hours annually; and

- The term $Scarcity\ Hours_{new}$ is the expected annual hours of scarcity conditions when the system is at planning criteria and new entry is required.

As a simple example, suppose a new resource has a capacity of 1 MW, its expected average annual performance is $Actual_{new}$ = .9 MW during scarcity hours, the expected average annual Capacity Balancing Ratio during scarcity hours is 60 percent (or 0.6), and the expected number of scarcity hours annually is 20. Assume for the purposes of this example only that the PPR value is $2,000 per MWh. In this simple example, the new resource's expected annual Capacity Performance Payment is:

$$Expected\ PP_{new} = \$2{,}000 \text{ per MWh} \times [.9 - .6] \times 20 \text{ hours per year}$$

$$= \$12{,}000 \text{ per MW-year.}$$

In this example, the resource's expected annual Capacity Performance Payments are positive. They are positive because its expected annual performance rate is 90 percent (calculated as 0.9 MW per MW of Capacity Supply Obligation), and this performance rate exceeds its annual expected Capacity Balancing Ratio of 60 percent. Stated equivalently, the new resource in this example expects that, over the course of the year, it will perform during scarcity conditions at a rate of 90 percent, which exceeds the expected share-of-system financial performance obligation during scarcity conditions of 60 percent.

Q: How do you translate the second economic principle into precise formulas?

A: The second economic principle requires a resource's expected net FCM revenue to be zero if the resource's owner expects it to have zero annual performance during scarcity conditions. To translate this principle into a formula, we can apply the same logic used in Condition (B) above. Note, however, that in this case the application of Condition (B) must also apply to existing resources because a 'zero performer' could be an existing resource whose performance has deteriorated to where it no longer expects to perform.

Specifically, we can re-state Condition (B) without the 'new' qualifier as the following formula:

$$Expected\ PP = PPR \times [Actual - Balancing\ Ratio] \times Scarcity\ Hours$$

The interpretation of each term in this formula is just as before.

To use this formula in the context of the second economic principle, note that if a resource expects never to perform during scarcity conditions, then – by definition – its value of *Actual* in this formula is zero. Accordingly, if we zero-out the *Actual* term above, we find that a resource that expects to have average annual performance of zero during all scarcity conditions has a negative *Expected PP* value per Capacity Supply Obligation MW-year of:

$$PPR \times [0 - Balancing\ Ratio] \times Scarcity\ Hours$$

which can be simplified to:

(C) $$-PPR \times Balancing\ Ratio \times Scarcity\ Hours.$$

I will refer to this as Condition (C).

The *Expected PP* value in Condition (C) is a negative number. In words, it equals the Capacity Performance Payment Rate for the resource's share of system requirements (given by the Capacity Balancing Ratio), applied in all expected scarcity hours during the year. In terms of the Pay For Performance design, this negative number represents the expected deviation settlement (per Capacity

Supply Obligation MW) for a resource with zero performance under the Pay For Performance two-settlement system.

Q: Why is this particular formula, Condition (C), important?

A: There is a key relationship between the expected deviation payment and the capacity clearing price. Consider a resource that expects to perform at zero during all scarcity conditions, in a year when new entry is required and new entry sets the capacity price. The second economic principle described above requires that if a resource's expected performance is zero, its expected negative Capacity Performance Payments must offset its Capacity Base Payment revenue from the capacity clearing price.

This requires, in expectation, that

(D) $$PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new} = Capacity\ Price_{new}$$

I will refer to this as Condition (D).

Excepting the sign change, the left hand side is the same formula obtained in Condition (C). It is the expected annual performance payment (per Capacity Supply Obligation MW) for a resource with zero expected performance in all scarcity conditions. In this scenario, however, we are considering a year in which

new entry occurs, so the appropriate number of scarcity hours is that when new entry occurs, or $Scarcity\ Hours_{new.}$

Moreover, in this scenario, the capacity clearing price is set by the new entrant. The capacity clearing price when new entry occurs is the value of $Capacity\ Price_{new}$. We used this same term earlier, in our explication of Condition (A).

Condition (D) is necessary for the second economic principle to be satisfied. To see this, suppose that, counter to fact, Condition (D) did not hold and (say) the capacity price exceeds the value of $PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new}$. Then a resource with zero expected performance has positive expected net FCM revenue, violating the second economic principle of zero expected revenue for zero performance.

Q: How did you combine these formulas to arrive at the final Full PPR formula?

A: The first and last conditions, Conditions (A) and (D) above, jointly determine the set of Capacity Performance Payment Rate values that satisfy the two main economic principles.

To see this, first determine the set of possible values for *PPR* that simultaneously make Conditions (A) true and Condition (D) true. We can do this by inserting Condition (D) into the left-hand side of Condition (A). That yields the following new formula:

$$PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new} + Expected\ PP_{new} \geq net\ CONE + RF_{new}$$

We can also use Condition (B), which is our definition of the term $Expected\ PP_{new}$, to write the previous formula in an equivalent way. Specifically, inserting the full expression for $Expected\ PP_{new}$ from Condition (B) in place of the single term $Expected\ PP_{new}$ in the left-hand side of the previous formula yields the following equivalent formula:

$$PPR \times Balancing\ Ratio \times Scarcity\ Hours_{new} + PPR \times [Actual_{new} - Balancing\ Ratio] \times Scarcity\ Hours_{new} \geq net\ CONE + RF_{new}.$$

In this expression, there are several terms on the left-hand size of the inequality sign that add and subtract the same quantities. They therefore cancel each other out and can be removed from that expression. The terms that remain are shown in the following equivalent formula:

$$PPR \times Actual_{new} \times Scarcity\ Hours_{new} \geq net\ CONE + RF_{new}.$$

Re-arranging these terms yields the formula for the Capacity Performance Payment Rate that satisfies the two starting economic principles. This formula is:

$$PPR \geq \frac{Net\ CONE + RF_{new}}{Scarcity\ Hours_{new} \times Actual_{new}}$$

I will refer to this as the Full PPR formula. In summary, this analysis shows that to satisfy the foundational economic principles underlying the Capacity Performance Payment Rate, the rate must satisfy this Full PPR formula.

Q: Can you interpret the Full PPR formula, in words?

A: Although the mathematical derivation of this formula takes many steps, the conclusion is economically sensible and simple to interpret. Stated succinctly, the Capacity Performance Payment Rate spreads the total capacity revenue that a new entrant requires over its expected annual output during scarcity conditions.

To see why, let's look at the pieces. The sum in the numerator of the Full PPR formula (*Net CONE* + RF_{new}) is the new entrant's total cost, including a risk premium (if any), that it must expect to recover from the capacity market in order to be willing to enter. The amount in the denominator (*Scarcity Hours*$_{new}$ × *Actual*$_{new}$) is the new entrant's expected total annual performance during scarcity conditions. Performance, in this context, is measured in MWh delivered in the form of energy or reserves, per Capacity Supply Obligation MW, during scarcity conditions. In this way, a new capacity resource earns its capacity revenue by performing during scarcity conditions.

Similarly, an existing capacity resource – one that clears in the auction, whether or not new entry sets price – earns greater net FCM revenue to the extent that it delivers more energy and reserves during scarcity conditions. These resources all have positive expected profit in the capacity market (with the possible exception of the marginal resource that sets the capacity clearing price, who expects zero profit).

Q: What if the Capacity Performance Payment Rate is set at a lower value than the Full PPR formula specifies? Would a new entrant still be willing to enter when new entry is required in order to satisfy the Installed Capacity Requirement?

A: Yes. If new entry is required, the Forward Capacity Auction will clear at a high enough price to clear the new entrant, and ensure the region meets the Installed Capacity Requirement. Because of this, even if the Capacity Performance Payment Rate was set at a low value that does not satisfy the Full PPR formula, the first economic principle would not be violated.

However, if the Capacity Performance Payment Rate is set at a lower value that the Full PPR formula specifies, the second economic principle – zero expected revenue for zero performance – would be violated. A zero performer would have positive expected profits, and may submit a capacity offer price less than that of a new entrant. Because of this, the zero performer could displace the new entrant.

Q: Please explain why a zero performer would not clear in the Forward Capacity Auction, whether or not new entry is required to satisfy the Installed Capacity Requirement, if the Capacity Performance Payment Rate is set according to the Full PPR formula?

A: If a capacity resource expects to have zero performance when the system is at criteria, its expected negative net Capacity Performance Payments will equal the offer price of the new entrant. That means its net expected FCM revenue will be zero, and therefore it will not find it profitable to acquire a Capacity Supply Obligation.

A different perspective on this property is to observe that, in order for a zero expected performer to cover its expected negative Capacity Performance Payments, the Capacity Base Payment it requires is *greater* than the Capacity Base Payment that a new entrant requires to be willing to enter. This means the zero expected performer will not clear in the forward auction, because a new entrant would instead. The fact that the zero expected performer will not clear when new capacity is required is by design; moreover, it implies that a zero expected performer will not clear if the capacity market has excess supply, because the Capacity Base Payment would be lower than when the capacity price is set by new entry.

That property is important from both an economic standpoint and from a reliability perspective. The Full PPR formula ensures that a zero expected performer cannot profit by displacing a reliable new entrant.

Q: What about resources that are in between, that is, neither new entrants nor zero expected performers? Does this Capacity Performance Payment Rate select these resources cost-effectively?

A: Yes. Because all resources are compensated at the same rate on the basis of their performance, better performers earn higher net FCM revenue; poor performers earn less. All resources that clear in the Forward Capacity Auction either have low capacity costs, high expected performance, or both. Conversely, the resources that fail to clear in the Forward Capacity Auction have high costs, poor expected performance, or both.

This differs from how the capacity market clears today, where resource may have low capacity offers and clear because they have minimized the capacity costs by not undertaking capital expenses that would improve their performance during scarcity conditions, when reliability is at heightened risk.

D. Determinants of the Full PPR Value

Q: Is it important for the numerical value of the Capacity Performance Payment Rate to be specified prior to the Forward Capacity Auction, even

though performance payments are not realized until three years later, during the Capacity Commitment Period?

A: Yes. From a commercial standpoint, it is important for the Capacity Performance Payment Rate value to be specified well in advance of the Forward Capacity Auction. A fixed value for the Capacity Performance Payment Rate avoids uncertainty over the deviation settlement price that will apply when a capacity supplier's performance is below or above its share of system requirements during scarcity conditions. This means that when a supplier evaluates its expected Capacity Performance Payments prior to bidding in the Forward Capacity Auction, the supplier faces only *quantity* risk – the MWh of its over- or under-performance during commitment period scarcity conditions – but it does not face *price* risk regarding the Capacity Performance Payment Rate at which its deviations are settled. For these reasons, the Capacity Performance Payment Rate is set forth in the Tariff, based on the foregoing principles and analysis.

Q: How did you determine the $5,455 per MWh numerical value for the Full PPR?

A: To determine the numerical value for the Full PPR, I used the Full PPR formula described above:

$$PPR \geq \frac{Net\ CONE + RF_{new}}{Scarcity\ Hours_{new} \times Actual_{new}}$$

For this purpose I evaluated each term that appears on the right-hand side of the Full PPR formula, using various sources of data for the New England system. I will explain each term and the value used for each term next.

Net CONE. This parameter is the net cost of entry for the most cost-effective generation type. Based on the recently-completed Offer Review Trigger Price analysis for New England, this is a combined cycle with an estimated annualized net cost of entry of $8.87 per kw-month, or $106,394 per MW-year.[20]

Risk Factor. For purposes of establishing the Capacity Payment Performance Rate, we assume the risk factor term RF_{new} is zero. This is appropriate under the assumption that a potential new entrant's next best alternative to acquiring a Capacity Supply Obligation is not materially more risky than acquiring it. This would be the case if a potential new entrant's next best alternative to acquiring a Capacity Supply Obligation is not to acquire one and to collect the Capacity Performance Payment Rate for the same performance, for example. Under that putative next best alternative, for a resource with high expected performance (*i.e.*, a value of $Actual_{new} = 0.92$), the volatility of its cash flows from year to year under the Pay For Performance design is *lower* by acquiring a Capacity Supply Obligation than if the resource relied solely on Capacity Performance Payments.

[20] *See* 2013 Offer Review Trigger Prices Study by The Brattle Group, submitted in *ISO New England Inc.*, Revisions to Forward Capacity Market Offer Review Trigger Price Provisions, Docket No. ER14-616-000 (filed December 13, 2013). The filing is currently pending at FERC.

I explain this property of cash flow volatility under Pay For Performance in greater detail in Section VI.B below.

In general, the ISO has no certain means by which it can ascertain the specific next best alternative use of a proxy new entrant's capital if it chooses not to acquire a Capacity Supply Obligation. Assuming a different (that is, positive) value for the risk factor term for purposes of establishing the Capacity Performance Payment Rate would result in a *higher* Capacity Performance Payment Rate than the numerical value proposed below.

Scarcity Hours at Criteria. The term $Scarcity\ Hours_{new}$ represents the expected number of scarcity hours annually when the system is at criteria, and new entry is required. To determine an appropriate value for $Scarcity\ Hours_{new}$, we employ the ISO's system planning model used to determine the Installed Capacity Requirement and related values. This model indicates that at planning criteria, the expected value of the number hours of operating reserve deficiencies is 21.2 hours per year.

In obtaining this value, we used the same inputs and assumptions as are employed in the ISO's probabilistic simulation model to set the Installed Capacity Requirement, with one exception. Other than that exception, these inputs and assumptions are detailed in the ISO's January 2013 report, *ISO New England Installed Capacity Requirement, Local Sourcing Requirement, and Maximum*

Capacity Limit for the 2016/2017 Capability Year,[21] and the principal results are filed with the Commission.[22] The exception is that we assumed that all Real-Time Demand Response ("RTDR") resources are able to supply reserves, or are available to supply energy, prior to a reserve deficiency. This is consistent with the Commission-approved ISO plans for the full integration of active demand response resources into the energy markets in 2017, but it differs from current RTDR dispatch practices as an action under Emergency Operating Procedures (OP-4 Load Relief), which generally occurs subsequent to an operating reserve deficiency.

The value of the number of scarcity hours used to determine the Capacity Performance Payment Rate is the ISO's system planning model's result when the system is at planning criteria. This value does not change materially from one year to the next. In particular, the estimates of scarcity hours when the system is at planning criteria is robust to annual variation in the amount of excess supply, or lack thereof, from one year to the next.

[21] Available at: http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/index.html.

[22] *See ISO New England Inc. and New England Power Pool*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2016/2017 Capability Year, Docket No. ER13-334-000 (filed November 6, 2012), accepted by letter order dated December 31, 2012.

As the overall mix of capacity resources in New England evolves and resource performance improves, the estimated number of scarcity hours when the system is at criteria may change slowly over time. However, this value is unlikely to drift significantly lower than current estimates, even as performance improves, because as performance improves (other things assumed equal) the Installed Capacity Requirement necessary to satisfy the region's resource adequacy criterion will also adjust downward.

Average Annual Performance. The term $Actual_{new}$ represents the average annual performance, per Capacity Supply Obligation MW, of a cost-effective new entrant. This is a number that ranges between zero (no performance) and, normally, one (perfect Capacity Supply Obligation performance). Performance above a resource's Capacity Supply Obligation MW is possible, in which case this value may exceed one.

Importantly, $Actual_{new}$ is not the Year 1 value of the new entrant's performance, but rather its expected average annual performance over the project owner's investment horizon when new entry occurs. We determine an appropriate value for $Actual_{new}$ based on the following:

- *Units and ages.* To determine an appropriate value for $Actual_{new}$ empirically, we examined the observed performance of 31 combined cycle generating facilities constructed in New England over the past 20 years. This sample

mirrors the 20-year investment horizon employed in the ISO's Offer Review Trigger Price analyses for the cost of new generation entry.

- *Actual performance during scarcity conditions.* For each facility, we calculated its average actual scarcity condition performance during the months of June, July, and August for the three-year period from 2010-2012. We use summer months' scarcity conditions performance because when the system is at criteria (requiring new entry), ISO planning models indicate nearly all expected scarcity hours are anticipated to occur during the summer months.

We then determined a trend line, via linear regression, that best explained the 31 facilities' observed performance rates as a function of the units' ages. The data show that average performance (the trend line) of these resources is a relatively flat function of facility age, declining from average performance of approximately 94 percent per MW for new (age 1 year) facilities to approximately 89 percent per MW for facilities at age 20. We use the midpoint of this range, or a value of $Actual_{new}$ = 0.92 per MW, as an appropriate value for a new combined cycle facility's average performance during scarcity conditions of over the project's investment horizon.

Q: How do you combine the values obtained from these data sources to obtain the Full PPR?

A: Using these values as inputs to the Full PPR formula derived previously, we obtain

$$PPR \geq \frac{Net\ CONE + RF_{new}}{H_{new} \times Actual_{new}} = \frac{\$106{,}394 \text{ / MW-year}}{21.2 \text{ hours/year} \times 0.92} = \$5{,}455 \text{ / MWh.}$$

While values above $5,455per MWh would also satisfy the inequality, the ISO will set the Full PPR at the smallest value that satisfies this requirement, or $5,455 per MWh.

Q: Did you make any adjustments for the cost of the FCM's Peak Energy Rent deduction in evaluating the Full PPR formula?

A: No. Since the Peak Energy Rent provisions were revised in December 2010, the value of the monthly Peak Energy Rent deduction has fallen substantially from prior years. Over the last three years, from 2011 through 2013, the cost of the Peak Energy Rent deduction has averaged four cents per kW-month. Accounting for this cost would not make a material difference in the value of the Full PPR.

E. The PPR Phase-In Period

Q: Please summarize the phase-in of the Capacity Performance Payment Rate.

A: The Pay For Performance changes incorporate a phase-in, over several years, of the Capacity Performance Payment Rate. Specifically, it will start at a lower

value for the ninth Forward Capacity Auction (conducted in February of 2015 for the Capacity Commitment Period beginning on June 1, 2018), and rise over time to reach the Full PPR value after a phase-in period of six Forward Capacity Auctions.

The proposed phase-in period is structured in two discrete steps, each of three years' duration, before the Full PPR is applied. Specifically:

- For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh. This corresponds to the 9th, 10th, and 11th Forward Capacity Auctions to be conducted in 2015, 2016, and 2017, respectively.

- For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. This corresponds to the 12th, 13th, and 14th Forward Capacity Auctions to be conducted in 2018, 2019, and 2020, respectively.

- For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh. This corresponds to the 15th Forward Capacity Auction, to be conducted in 2021, and thereafter.

During the first step, the Capacity Performance Payment Rate is set at $2,000 per MWh, which is (slightly more than) one-third of the Full PPR of $5,455 per MWh. During the second step, the Performance Payment Rate increases to (approximately) two-thirds of the Full PPR rate of $5,455 per MWh. The full rate would be in effect for the 2024-2025 Capacity Commitment Period, so the complete design takes effect approximately 10 years from now.

Under this phase-in schedule, the second step provides a three year 'overlap' period in which market participants would observe the system's operating experience under the Pay For Performance design, as well as their individual resources' performance. This occurs at a Capacity Performance Payment Rate less than the Full PPR.

Q: Why does Pay For Performance incorporate a phase-in period for the Capacity Performance Payment Rate?

A: The ISO understands that Pay For Performance represents a major shift in the Forward Capacity Market design that will significantly impact the capacity revenue streams for some suppliers and impact costs to consumers. It is reasonable to smooth the transition to the new paradigm, and phasing in the Capacity Performance Payment Rate will help to accomplish that. The lower initial value will tend to reduce the financial risk and uncertainties that capacity sellers face under the Pay For Performance design while participants gain

experience with the design prior to the full Capacity Performance Payment Rate becoming effective.

During the phase-in periods, market participants will acquire greater information and experience about the frequency, timing, and duration of scarcity conditions on the system. They will also acquire years of additional experience with how their individual resources perform during these conditions. This additional information will help suppliers better gauge the risks and rewards they face under the new design, provide additional time for new bilateral arrangements to develop in the marketplace that can help manage and spread risk, and enable the region to better assess the likely impacts of incremental changes in the Capacity Performance Payment Rate on Forward Capacity Auction prices prior to reaching the full Capacity Performance Payment Rate.

Q: Are there any trade-offs or concerns associated with using a lower Capacity Performance Payment Rate during the phase-in period?

A: There are some performance trade-offs that come with the lower Capacity Performance Payment Rate. A lower rate will result in lower marginal incentives for performance during scarcity conditions. However, here it is paramount to observe that the primary role of the Capacity Performance Payment Rate, and the capacity market generally, is to induce cost-effective long-run investments in resources' capabilities. An investment decision is not made on the basis of the Capacity Performance Payment Rate during any single year; it is based on the

present value of the revenue streams the investment will generate over its useful life. This means that resource owner's investment decisions in response to the Pay For Performance design will be determined in significant part, if not primarily, by the Full PPR value that will apply for most of the life of the investment.

In fact, the phase-in period is likely to affect investments largely by shifting the timing of investment. Suppose, for instance, that a resource owner could undertake a particular capital expense that would improve the resource's performance and that the expense would be a profitable undertaking, in present value terms, if paid the Full PPR value of $5,455 per MWh for its performance. Conceivably, this capital expense might not be a profitable investment if the owner is paid a lower Capacity Performance Payment Rate of $2000 per MWh for performance indefinitely. However, since the lower value is transitory, and the investor would undertake the new investment eventually when it faces the Full PPR (by assumption), the decision of whether to undertake this investment during the phase-in period is a financing question – that is, a matter of the time value of money.

Specifically, a profit-minded owner would undertake the capital investment during the phase-in period as long as the incremental performance payment revenue it brings during the phase-in period exceeds the foregone interest on deferring the capital expense until the Full PPR value arrives. That is, a profit-

maximizing resource owner will not seek to recover the total cost of the investment based on the lower rate, but only the interest cost of accelerating the investment before the Full PPR value arrives. This standard financial logic implies that, because investors know the Full PPR value in the Tariff and the date when it will take effect, the phase-in period may have only a small impact in deferring new investments that can improve resource performance.

VI. PAY FOR PERFORMANCE WILL IMPROVE RELIABILITY IN A COST-EFFECTIVE MANNER

A. Pay For Performance Yields Cost Effective Resource Selection, While The Current FCM Does Not

Q: You have stated above that Pay For Performance produces a cost-effective and more reliable resource mix. What do you mean by cost-effective?

A: The logic of cost-effective resource selection is simple. Cost-effectiveness is the ratio of cost to performance. If two resources have the same capacity cost, but one resource has better performance during scarcity conditions, then a well-designed capacity market should select the better performing resource. More generally, if the capacity market selects resources cost-effectively, then the resources that clear will either have low capacity costs, high reliability, or both. In contrast, the flawed aspects of the current FCM have the undesirable result that

the capacity market may clear resources that have little or no contribution to reliability.

Q: Can you illustrate cost-effectiveness with a simple example?

A: Yes. Suppose a resource has capacity of 10 MW and a capacity cost of $3 per kw-month. This means its owner would require a net expected capacity payment of at least $3 per kw-month to be willing to acquire a Capacity Supply Obligation. Let's assume it is a moderately poor performer, with average annual performance of 2 MW (in the form of energy and reserves) during scarcity conditions.

Now consider a better-performing competing resource, also with capacity of 10 MW but with average annual performance of 8 MW during scarcity conditions. This resource has a higher capacity cost of $4 per kw-month.

Which resource is more cost-effective? Using round numbers for purposes of this example only, assume there are 20 scarcity hours per year. Then:

- The moderately poor performer has an annual capacity cost of $3 per kw-month × 10 MW × 12 months/year × 1000 = $360,000 per year. It has expected annual performance during scarcity conditions of 2 MW × 20 hours per year of scarcity = 40 MWh per year.

Its cost / performance ratio is therefore: $360,000 / 40 MWh = $9,000 per MWh.

- The better performer has an annual capacity cost of $4 per kw-month × 10 MW × 12 months/year × 1000 = $480,000 per year. It has expected annual performance during scarcity conditions of 8 MW × 20 hours per year of scarcity = 160 MWh per year.

  Its cost / performance ratio is therefore: $480,000 / 160 MWh = $3,000 per MWh.

In this example, the better performer is more cost-effective by a factor of three. However, the current FCM design is more likely to clear the less cost-effective resource. Assuming each resource bids competitively, the worse-performing resource's bid of $3 per kw-month is lower than the better-performing resource's bid of $4 per kw-month. In this way the current FCM tends to obtain a resource mix that is biased toward resources that deliver less energy and reserves during scarcity conditions, when reliability is at heightened risk.

Q: From an economic perspective, why does cost-effectiveness matter?

A: Recall the discussion of scarcity revenue from Section III.C above. From an economic perspective, the capacity market serves to provide suppliers with the additional scarcity revenue that the energy market fails to provide and that is

necessary to achieve the region's reliability criteria. A resource's cost-effectiveness has the useful interpretation as the minimum additional scarcity price "premium" that it must be paid in the capacity market in order for the resource to cover its total costs and be willing to operate.

To see this, consider the better-performing resource in the previous example. To cover its capacity cost, it requires average capacity market revenue of $3,000 for each MWh it expects to deliver during scarcity conditions. This capacity market revenue is in addition to the scarcity revenue that it receives in the energy market for delivering the same MWh. Thus, the energy and capacity markets jointly will enable this resource to cover its total costs if, and only if, it receives the energy market's existing scarcity price *plus* a scarcity price premium of $3,000 per MWh via the capacity market.

Stated differently, if New England had no capacity market at all, it could retain the better-performing resource only if the energy market's scarcity price was increased by $3,000 per MWh. Similarly, it could retain the worse-performing resource in the previous example only if the energy market's scarcity price was increased by three times as much, or $9,000 per MWh. Put simply, a resource's cost effectiveness has a simple and important economic interpretation: it is the scarcity price premium the resource requires from the capacity market in order to operate profitably.

Q: What does the interpretation of cost-effectiveness as a scarcity price premium imply for capacity market design?

A: The concept of cost-effectiveness is important to capacity market design for two reasons. First, it means that the scarcity price premium that consumers are in effect paying, through the capacity market, will be minimized if and only if the capacity market selects the most cost-effective set of resources. In a pure energy market with enough resources to meet the region's resource adequacy criterion, scarcity prices would have to be much higher than today but the energy market would naturally select the most cost-effective set of resources. Similarly, under Pay For Performance, resources will be selected by the Forward Capacity Auction on the basis of their cost effectiveness. Under the current FCM, however, resources are not selected on the basis of cost effectiveness. That means that consumers, implicitly, are frequently paying an unnecessarily high scarcity price premium for the level of service they obtain during scarcity.

The second reason cost-effectiveness matters is for what it reveals about implicit pricing. The current FCM design is effectively a system of price discrimination, but this is masked by the current FCM's flawed performance metric. To see this, suppose both of the resources in the previous example clear in the capacity market under the current rules, at a capacity clearing price of $4 per kw-month. As shown previously, the capacity market will pay the better performer $3,000 per MWh for the energy (and reserves) it delivers during scarcity conditions. But in this scenario the worse-performing resource receives the same total capacity

revenue of $480,000 as the better-performer, while delivering fewer MWh during scarcity conditions. That gives it an effective scarcity price premium of $480,000 / 40 MWh = $12,000 per MWh delivered. The poor-performer is paid an effective scarcity price premium that is four times greater than that paid to the better-performer.

The use of scarcity prices in the energy market would never produce this type of price discrimination, because in the energy market both resources receive the same price per MWh delivered during scarcity conditions. However, in the current capacity market they receive quite different effective scarcity prices. Moreover, this type of price discrimination works in an especially problematic way: It pays higher effective prices to resources that perform poorly. In fact, the worse a capacity resource performs, the *higher* the effective scarcity price it receives under the current capacity market design.

It should come as no surprise then that poorly performing resources find it profitable to remain in the current capacity market and that New England has deteriorating performance across the fleet.

Q: How does the Pay For Performance design select resources on the basis of cost-effectiveness in the Forward Capacity Auction to solve that problem?

A: Unlike the current FCM design, with Pay For Performance the FCM will clear a more cost-effective set of resources. This works because resources are incented

to account for their expected performance when they bid in the Forward Capacity Auction, and each resource's capacity offer price will reflect the resource owner's own estimate of its cost-effectiveness.

This is one of the most important economic features of the Pay For Performance design. I will therefore walk thru how this works in some detail, using an extended example.

Consider two different 100 MW resources. Resource 1 is a moderate performer, with an annual average performance of 0.6 per MW during scarcity conditions and a capacity cost of $2.25 per kw-month. Resource 2 is a poor performer, with an annual average performance of 0.1 per MW during scarcity conditions and a lower capacity cost of $0.75 per kw-month.

Because Resource 1 has higher expected performance than Resource 2, there are different reliability consequences if the Forward Capacity Auction awards a Capacity Supply Obligation to Resource 1 or Resource 2. Resource 1 has expected performance during scarcity conditions of:

Resource 1: 100 MW × 0.6 *performance rate* = 60 MW.

By contrast, Resource 2 has expected performance during scarcity conditions of:

Resource 2: 100 MW × 0.1 *performance rate* = 10 MW.

Although both resources are assumed qualified to acquire a Capacity Supply Obligation of 100 MW, the expected amount of energy and reserves delivered during scarcity conditions is six times greater if the Forward Capacity Auction awards the obligation to the moderately-performing Resource 1 instead of the poorly-performing Resource 2.

First, let's examine the outcome of the Forward Capacity Auction under the Pay For Performance design. For this, a few additional market assumptions are necessary. First, assume the Full PPR of $5,455 per MWh. Next, assume – for purposes of this example only – that there are 10 hours of scarcity conditions annually, an annual average balancing ratio of *BR* = 0.9, and the Capacity Clearing Price is $4 per kW-month.

Though I use this particular set of assumptions strictly for example purposes here, these assumptions correspond (approximately) to the conditions of the "Near Term Equilibrium" FCM scenarios estimated by the Analysis Group Inc. in its in the report entitled "Assessment of the Impact of ISO-NE's Proposed Forward

Capacity Market Performance Incentives" dated September 2013 and provided in Attachment I-1g of this filing (the "Impact Assessment").[23]

Using the previous formula for *Expected PP* (expected Capacity Performance Payments) shown in Condition (B) earlier in my testimony (*see* Section V.C), we can calculate each resource's expected profit from acquiring a Capacity Supply Obligation. The table below shows each resource's base capacity price, expected performance payment, capacity cost, and expected profit, all shown on a per kw-month basis.

	Capacity Price	*Expected PP*	*Capacity Cost*	*Expected Profit*
Resource 1	\$4	– \$1.36	– \$2.25	\$0.39
Resource 2	\$4	– \$3.64	– \$0.75	– \$0.39

The calculation to obtain the expected performance payment for Resource 1 is

Expected PP for Resource 1 = \$5,455 × [60 MW – 90% × 100 MW CSO] × 10 hours

This equals –\$1,636,500 per year, or –\$1.36 per Capacity Supply Obligation kW-month as shown in the table. Similarly, for Resource 2,

[23] Impact Assessment at 30 (Table 4).

Expected PP for Resource 2 = $5,455 × [10 MW – 90% × 100 MW CSO] × 10 hours

This equals –$4,364,000 per year, or –$3.64 per Capacity Supply Obligation kW-month as shown in the table.

Assuming both resources bid competitively (and in an expected profit-maximizing manner), Resource 1 would clear in the Forward Capacity Auction. Using the values shown in the table, Resource 1's competitive bid is the sum of its capacity cost and expected performance payment (which is in this case negative, representing a net charge), which is $1.36 + $2.25 = $3.61 per kw-month. This is less than the market-clearing capacity price of $4 per kw-month, so it clears. Resource 1 then has an expected net profit of $0.39 per kw-month.

Resource 2 would *not* clear in the Forward Capacity Auction. Its bid would need to cover its expected costs of $3.64 + $0.75 = $4.39 per kw-month in order to break even, given its expected performance charges. This break-even bid exceeds the clearing price of $4 per kw-month. Resource 2 is better off not clearing, because at a capacity price of only $4 per kw-month the resource would have a negative expected profit of –$0.39 per kw-month as shown in the table

Note further that, in this scenario, the Forward Capacity Auction clears the better-performing Resource 1, and does not clear the poorer-performing Resource 2.

That is, at the full proposed Capacity Performance Payment Rate, the market selects the correct resources from the standpoint of expected resource performance. Although Resource 1's capacity cost is three times larger than Resource 2's, Resource 1 delivers *six* times the expected energy and reserves during scarcity conditions – making Resource 1 a more cost-effective way to meet the system's requirements for energy and reserves during scarcity conditions.

Now, let's turn to the market outcome under the current FCM design. Under the current design, there is no Capacity Performance Payment Rate. For purposes of this example, I will assume that without Pay For Performance the market clears at a lower Capacity Clearing Price of $1.75 per kw-month.

Proceeding similarly to the previous scenario, we can calculate each resource's expected profit from acquiring a Capacity Supply Obligation. The table below again shows each resource's base capacity price in the scenario without Pay For Performance, expected performance payment (now zero), capacity cost, and expected profit, all shown on a per kw-month basis.

	Capacity Price	*Expected PP*	*Capacity Cost*	*Expected Profit*
Resource 1	$1.75	$0	– $2.25	– $0.50
Resource 2	$1.75	$0	– $0.75	$1.00

Without Pay For Performance, the market-clearing resources are reversed. The poor-performing Resource 2's competitive bid in the auction is its capacity cost of

$0.75. This bid would clear in the Forward Capacity Auction at a clearing price of $1.75, giving the poor-performing Resource 2 an expected profit of $1.00 per kw-month.

The moderately-performing Resource 1 would *not* clear, however. Its Forward Capacity Auction bid would need to cover its capacity cost of $2.25 per kw-month in order to break even, which exceeds the market-clearing price of $1.75 per kw-month. In effect, without Pay For Performance, the FCA *fails* to select the correct resources from the standpoint of resource performance.

Q: What are the main implications of this example?

A: This example reveals that without Pay For Performance, there are three potential adverse outcomes:

- resources with poor performance may clear in the Forward Capacity Auction, displacing competing resources with substantially better performance;

- the market produces a worse-performing resource mix, which lowers the amount of energy and reserves the ISO can expect to obtain during tight system conditions when reliability is at heightened risk; and

- perversely, suppliers find poor performance may be *more* profitable than better performance.

The ISO's proposed Capacity Performance Payment Rate is designed to reverse all three problems. The less reliable and less cost-effective resources will tend to de-list (not clear) in the Forward Capacity Auction, rather than displace resources with more cost-effective performance.

Q: How do the potential outcomes illustrated in this example relate to the concept of cost-effectiveness that you discussed previously?

A: The Capacity Performance Payment Rate enables the Forward Capacity Auction to select the set of resources that most cost-effectively meet the system's needs during scarcity conditions. That is, it selects resources with the lowest capacity costs *relative to* the expected amount of energy (and reserves) that the resources will deliver.

To see this in the context of Resources 1 and 2, the table below summarizes the attributes of each resource in the example above. The final column tabulates each resource's cost-effectiveness, that is, the ratio of its annual capacity cost to its annual performance.

	Capacity (MW)	*Performance per Scarcity*	*Expected Scarcity*	*Annual Performance*	*Capacity Cost*	*Cost / Performance*
Resource 1	100	60	10	600	$ 2.25	$4,500
Resource 2	100	10	10	100	$ 0.75	$9,000

The far-right column shows that Resource 1's capacity costs $4,500 for each MWh expected during scarcity conditions. Resource 2 is *more* costly in these terms. It has a capacity cost of $9,000 for each MWh expected during scarcity conditions.

The Capacity Performance Payment Rate clears Resource 1 instead of Resource 2 because it leads profit-maximizing resources to bid into the FCA on the basis of their cost effectiveness. In terms of the scarcity price premium explained earlier, Resource 1 requires a minimum scarcity price premium in the capacity market of $4,500 per MWh that it expects to deliver during scarcity conditions over the Capacity Commitment Period. This minimum scarcity price premium that it requires is less than the full Capacity Performance Payment Rate of $5,455 per MWh that it receives in the FCM. Since the capacity market's payment rate exceeds the minimum scarcity price premium at which it is willing to sell, Resource 1 is profitable in the capacity market and will clear in the Forward Capacity Auction.

Resource 2 requires a minimum scarcity price premium in the capacity market of $9,000 per MWh that it expects to deliver during scarcity conditions over the Capacity Commitment Period. This minimum scarcity price premium is *greater* than the full Capacity Performance Payment Rate of $5,455 per MWh that it would receive in the FCM for what it delivers during scarcity conditions. Since the capacity market's payment rate is less than the minimum scarcity price

premium at which it is willing to sell, Resource 2 is not profitable in the capacity market. Its minimum bid, as shown earlier, will not clear in the Forward Capacity Auction under Pay For Performance.

The central insight of the two-settlement design used in Pay For Performance is that at the Full PPR, it leads any competitive expected profit-maximizing resource to bid into the capacity market *as if* it was offering the minimum scarcity price premium it requires to be willing to accept a Capacity Supply Obligation and deliver its expected energy and reserves during scarcity conditions. By clearing the lowest-priced bids in the Forward Capacity Auction under Pay For Performance, the capacity market is selecting the set of capacity resources that are most cost effective: that is, that have the lowest capacity cost per MWh delivered during scarcity.

As this example illustrates, these properties enable the Pay For Performance design to select cost-effective resources and to produce a resource mix with superior performance than the existing FCM.

Q: What happens if there are insufficient existing resources with offers that correspond to a scarcity price premium of less than $5,455 per MWh?

A: In this case, the Forward Capacity Auction will clear new entry. In market equilibrium, when the capacity clearing price reflects the cost of new entry, all existing resources that have cost-effectiveness less than the Full PPR can clear

and profit in the FCM by bidding competitively. A resource that has cost-effectiveness in excess of the Full PPR will not clear, because the auction will clear a cost-effective new entrant instead.

Q: What about when the Capacity Performance Payment Rate is $2,000 per MWh, during the phase-in period?

A: During the phase-in period, some existing resources that are not cost-effective, in comparison to a cost-effective new entrant, may still clear in the Forward Capacity Auction. The extent to which this will occur will be less than occurs today under the current, flawed FCM design. Moreover, the extent to which it occurs will dissipate as the Capacity Performance Payment Rate increases to its full value.

Q: Is the explanation that the capacity market will clear a better-performing resource mix under Pay For Performance corroborated by empirical or simulation evidence for the New England system?

A: Yes. As I noted previously, the Analysis Group performed a study of the impacts of the Pay For Performance design. Part of their work involved prospective simulations of resource bids and what resources would clear under Pay For Performance, relative to a continuation of the existing FCM rules.

The resource-level results of their prospective simulations are reported in the Impact Assessment.[24] The points illustrated in my preceding example are corroborated in the empirical findings from the Analysis Group's study. For example, consider the region's oil-fired units, for which performance ranges widely (across units) historically during scarcity conditions.

- In the Analysis Group's findings without Pay For Performance, Table 6 (page 38) estimates 1,047 MW of these resources fail to clear in the Forward Capacity Auction. These de-listed resources have an average performance of 39 percent during scarcity conditions.

- With Pay For Performance and a Capacity Performance Payment Rate of $5,455 per MWh, the total de-listing resources in this group increases to 2,282 MW. However, there is a dramatic change in *which* resource de-list. These 2,282 MW delisting do not include (all of) the 1,047 MW that delist without Pay For Performance. Rather, the 2,282 MW are among poorest performers of this resource group, exhibiting average annual performance of only 14 percent during scarcity conditions.

[24] Impact Assessment at 38 (Table 6).

This indicates that without Pay For Performance, the FCM will tend to produce a poorer performing resource mix. With Pay For Performance and the full Capacity Performance Payment Rate, the FCM obtains a resource mix with superior performance.

B. Placing Performance Incentives in the Capacity Market Produces Less Volatility in Suppliers' Revenue and Consumers' Expenditures than Placing Comparable Performance Incentives in the Energy Market

Q: You stated above that the Capacity Payment Performance Rate can be interpreted as a scarcity price premium. At a high level, what are the economic differences if this premium was instead incorporated into the scarcity price in the energy market?

A: By design, the Capacity Performance Payment Rate applies to a resource's performance only during scarcity conditions. Similarly, the ISO's existing administrative scarcity price adder in the energy market also applies to the real-time energy price only during scarcity conditions.

In theory, the ISO's market design could place the full marginal incentive (that is, incorporate the full Capacity Performance Payment Rate) into the energy market's scarcity price. However, doing so would have different implications for some market outcomes. The most important difference concerns market volatility.

Specifically, the Pay For Performance design will produce more stable total revenues for suppliers over time. Incorporating the same scarcity price premium entirely in the energy market's price would yield more volatile net revenues for suppliers over time. This is true even though the combined scarcity price – that is, the magnitude of the marginal incentive to perform – is the same in both alternatives.

In addition, and for similar economic reasons, there would be greater volatility in total market expenditures for buyers. Wholesale market buyers, and potentially consumers, would face greater volatility of total costs if the scarcity price premium is placed into the energy market, instead of being implemented as an element of the capacity market using the Pay For Performance design.

Q: Why does the Pay For Performance design have this stabilizing effect, relative to the placing the performance incentive in the energy market?

A: The difference in net revenue stability reflects an important economic principle. As explained in Section IV.A earlier in my testimony, Pay For Performance is based on a two-settlement market design involving a forward sale, with subsequent performance payments based on deviations from a forward financial position. This two-settlement design reduces a seller's exposure to revenue fluctuations that arise from uncertainties *beyond* its individual performance.

In particular, a supplier's total annual scarcity revenue is sensitive to fluctuations in weather, which can cause the total number of scarcity hours to vary from year to year. Whether a scarcity price premium is vested in the energy or in the capacity market, most suppliers' scarcity revenues will depend on the actual number of scarcity hours during the Capacity Commitment Period. However, the two approaches differ significantly with respect to how *much* a supplier's net revenue will vary with the number of scarcity hours.

This is easiest to see in the special case where a capacity resource has average performance (per Capacity Supply Obligation MW) that is equal to its average share of system obligation over the Capacity Commitment Period. In this case, under Pay For Performance, an increase in the number of actual scarcity hours during the Capacity Commitment Period has *zero* effect on its FCM revenue. This resource covers it obligations perfectly with its own performance, so has no deviation payments in FCM settlement under Pay For Performance regardless of the number of scarcity hours.

The same insight is useful for resources with average performance that is higher, or lower, than the annual average balancing ratio. The smaller a resource's average deviation from the Capacity Balancing Ratio under Pay For Performance over the course of the year (where positive and negative deviations offset), the more the Pay For Performance design will smooth out the swings in a supplier's

total revenue when the number of scarcity hours during the Capacity Commitment Period turns out to be either higher, or lower, than it anticipated.

By contrast, imagine the same scarcity price premium was instead incorporated into the energy market. One more scarcity hour would increase the supplier's total scarcity revenue, by the product of the total scarcity price and the amount of energy (and reserves) it provides at the time. One fewer scarcity hour each year would reduce the resource's annual revenue in the same way. The resource is completely financially exposed to the full effect of fluctuations in the number of hours in which scarcity conditions occur each year. With the high scarcity price premium that is necessary to induce economically sound performance incentives, a resource in this situation could face considerable volatility in its total earnings each year.

In effect, the two-settlement design of Pay For Performance provides a capacity supplier with a three-year forward partial hedge against fluctuations in its total scarcity revenue. The hedge is only partial because it helps hedge against underlying risk drivers that are systematic (such as weather) and lead to changes in the number of total scarcity hours per year. It does not hedge against fluctuations in an *individual* resource's performance, however. That would dilute the resource's performance incentives, contrary to the intent of the design. Placing the scarcity price premium in the energy market alone provides no such

hedge, and results in greater volatility in a suppliers' total revenue from year to year.

Q: **Why is this revenue stabilizing property important?**

A: A central practical concern with placing the performance incentive solely, or even largely, in the energy market is that it is more likely to precipitate boom-and-bust cycles for suppliers. It leaves capacity suppliers with less insulation from the financial consequences of uncertainty in the number of scarcity hours each year. This quantity could vary significantly for a number of reasons, including a mild versus a severe weather year, a significant disruption to the region's fuel supply infrastructure, and the amount of excess capacity on the system in future years.

The ISO's Pay For Performance design provides the typical capacity resource with a greater level of insulation against the revenue swings than would occur due to these uncertainties. In general, this is desirable because net revenue stability is likely to facilitate new entry and reduce the cost of financing capital investments. As shown above, the Pay For Performance design works to provide more stable net revenues for the typical capacity resource over time, relative to placing the performance incentive in the energy market.

Q: You indicated earlier that placing the performance incentive in the energy market, rather than in the capacity market using the Pay For Performance

design, would also increase the volatility of consumers' costs. Why is that the case?

A: A hallmark of the Pay For Performance design is that consumers pay just the Forward Capacity Auction clearing price, determined three years ahead of the commitment period. Consumers do not bear the short-run risk of paying unexpectedly high Capacity Performance Payments after the capacity auction. This is achieved because the performance incentives under the Pay For Performance are structured as transfers among suppliers.

In contrast, in the energy market, the analogous performance incentive component is provided by the administratively-determined scarcity price adder in the real-time energy market. This means market participants that buy in the real-time market directly assume the costs of the performance incentive (*i.e.*, the scarcity price). If the high scarcity price is of similar magnitude to the full Capacity Performance Payment Rate, or $5,455 per MWh, then wholesale buyers could face real-time prices that are an order of magnitude greater than what they have experienced during similar stressed system conditions in the past.

Moreover, because participants in the Day-Ahead Energy Market have strong incentives to anticipate (and profit from) real-time price spikes – by bidding up day-ahead prices – it should be expected that some of the real-time market's increased volatility will result in higher prices in the Day-Ahead Energy Market.

In effect, placing the scarcity price premium in the energy market changes the traditional 'hedge' that the capacity market provides to buyers and, ultimately, consumers. It would expose load serving entities to greater volatility in their total procurement costs from year to year, as compared to the Pay For Performance approach. The underlying logic is that because suppliers incorporate their expected performance payments into their Forward Capacity Auction bids, the cost of these incentives to consumers is based on the *expected* number of scarcity hours during the Capacity Commitment Period. In contrast, the cost that consumers would bear if the same scarcity price premium is incorporated into the energy market is determined by the *actual* number of shortage hours that occur. Total costs are more predictable using the Pay For Performance design because the expected number of scarcity hours is more stable than the actual number of shortage hours that occur each year. That is, while on average there may be 20 shortage hours each year, in any given year there could be many more or far fewer.

In summary, the Pay For Performance design is able to achieve the same financial performance incentives for suppliers, while providing more stable total costs to buyers over time.

VII. OTHER IMPORTANT FEATURES OF THE PAY FOR PERFORMANCE DESIGN

A. Capacity Scarcity Conditions Complement Scarcity Pricing In The Energy Market

Q: What is a "Capacity Scarcity Condition"?

A: So far in my testimony, I have referred to "scarcity conditions" generally. In the Pay For Performance design, the scarcity conditions in which performance will be measured are well defined, and are referred to as "Capacity Scarcity Conditions."[25]

Q: Can Capacity Scarcity Conditions occur at a zonal level, or only at the system level?

A: The New England system is partitioned into a set of Capacity Zones. A Capacity Scarcity Condition can occur in all Capacity Zones at the same time, indicating that, at the system level, reserves are insufficient (in a precise sense that I will describe below). A Capacity Scarcity Condition can also occur in a single Capacity Zone that has a zonal real-time reserve requirement.

At present, there are two import-constrained Capacity Zones associated with contiguous Reserve Zones: The Connecticut Zone, and the NEMA/Boston Zone. It is possible for a scarcity condition to occur in one or the other of these two

[25] *See* revised Tariff Section III.13.7.2.1.

zones (or both) at a time when there is ample supply in the rest of the system, and therefore the system as a whole does not experience a scarcity condition.

If a scarcity condition occurs in only a portion of the New England system, it is important for the strong performance incentives created by Pay For Performance to apply to resources that can alleviate it. This is consistent with the overall objective of Pay For Performance to provide greater financial incentives for investments that will improve resource performance in the times – and in the locations – that supply is scarce and the system faces heightened reliability risk.

Q: What is the trigger for a Capacity Scarcity Condition?

A: At a high-level, Capacity Scarcity Conditions occur when the supply of energy and real-time reserves is insufficient to meet the applicable load and reserve requirements. This applies to the system as a whole, as well as to the individual zones explained above. The scarcity conditions during which a resource's performance is assessed under Pay For Performance correspond to the conditions in which the ISO's existing scarcity price adders are incorporated into the energy price.

Scarcity pricing in the energy market is based on the supply of real-time reserves relative to real-time reserve requirements. The ISO has several distinct reserve requirements, and different types of real-time reserves. There are three primary real-time reserve requirements, and a Capacity Scarcity Condition will be based

on whether the real-time energy price incorporates a scarcity price adder (indicating the supply of reserves is less than the required level of reserves) for one or more of the following reserve requirements:

(i) The *system minimum 30-minute reserve* requirement, which is satisfied with offline or online generation capability available in thirty minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' thirty-minute operating reserves ("TMOR"), ten minute non-spinning reserves ("TMNSR"), and ten-minute spinning reserves ("TMSR").

(ii) The *system 10-minute reserve* requirement (sometimes called the system's *contingency reserves* requirement), which is satisfied with offline and online generation capability available in ten minutes or less. The supply of reserves that helps satisfy this requirement includes all resources' TMNSR and TMSR.

(iii) The *zonal 30-minute reserve* requirements, for the zones described above. The supply of reserves that helps satisfy this requirement includes the resources within the zone providing TMOR, TMNSR, and TMSR.

This list does not include a zonal 10-minute reserve requirement, because the New England system does not have a 10-minute reserve requirement at the zonal level.

Q: If the supply of real-time reserves is deficient, does that always trigger a Capacity Scarcity Condition?

A: No, there are circumstances in which it may not. These circumstances arise in the same way, and are treated in the same way, under scarcity pricing in the energy market and under Pay For Performance. That is, a Capacity Scarcity Condition occurs under the same circumstances in which a deficiency of one of these three types of real-time reserves results in its scarcity price adder being incorporated into the energy price.

To explain these circumstances precisely, it is helpful to explain more specifically how scarcity pricing is triggered in the real-time energy and reserves markets. If the system's real-time dispatch software indicates there is a deficiency (that is, the supply of reserves is less than the required level of reserves) in one or more of these reserve requirements, then the price in the real-time reserve market is set by the ISO's administratively-determined reserve scarcity prices. As mentioned above, these reserve scarcity prices are called Reserve Constraint Penalty Factors ("RCPFs") in the Tariff.

Generally, if the real-time reserve market price is set by a RCPF, then the energy market price will incorporate this RCPF. In simple terms, that means that the real-time LMP for energy is determined by the energy market offer price of the marginal resource supplying reserves, *plus* the value of the RCPF (for the reserve requirement that is deficient). In this way, an RCPF serves as the energy market's scarcity price 'adder' when there is a deficiency of real-time reserves.

There are exceptions to the general process just described. Specifically, in the real-time energy and reserves markets, there are certain circumstances in which the reserve market price may be set by the RCPF value but no reserve scarcity price adder is incorporated into the energy market price. For example, if the system is ramping total energy production up to match rapidly climbing load, the system may have a transitory violation of a reserve requirement that could not be reduced even if the system had one less MW of energy demand. In this case, the real-time LMP for energy does not incorporate the reserve market's scarcity price. That is, the reserve market has an RCPF-based price, but there is no scarcity price adder incorporated into the energy price. In technical terms, this is known as a situation in which the system's resource ramping limitations are not binding on the system's energy dispatch.

Capacity Scarcity Conditions apply in the same way. In general, they are triggered whenever the system's real-time dispatch software indicates that there is a deficiency (that is, the supply of reserves is less than the required level of

reserves) for one or more of the three reserve requirements listed above. However, a Capacity Scarcity Condition is not triggered if the reserve market has an RCPF-based price, but there is no scarcity price adder incorporated into the energy price. In the Tariff, this provision is addressed in the definition of a Capacity Scarcity Condition, which specifically excludes the circumstance in which RCPF-based pricing occurs in the reserve market only because of resource ramping limitations that are not binding on the energy dispatch.

In Section III.C earlier in this testimony, I explained that a well-designed capacity market should provide performance incentives based on resource performance during scarcity conditions. I further indicated that these performance incentives should be complementary to, and in harmony with, scarcity pricing in the energy market. As explained here, the close correspondence between a Capacity Scarcity Condition and the conditions that result in scarcity pricing in the energy price (that is, the real-time LMP) mean that the Pay For Performance design honors these characteristics of a well-designed capacity market.

Q: Does scarcity pricing in the energy market occur at the same five-minute frequency with which Capacity Scarcity Conditions are measured for determination of Capacity Performance Payments?

A: Yes. In the real-time energy and reserve markets, the ISO calculates energy and reserve prices at a five-minute frequency. It is possible for scarcity pricing in the energy and reserve markets to occur for a time period as brief as five minutes.

Because Capacity Scarcity Conditions are based on the same system dispatch conditions that result in scarcity adders being incorporated into the energy market price, Capacity Scarcity Conditions are therefore measured on the same frequency. It is similarly possible for a Capacity Scarcity Condition to be as brief as five minutes.

There is an important practical reason why energy market scarcity pricing and Capacity Scarcity Conditions are calculated at a five-minute frequency. Periods of heightened reliability risk can occur abruptly, such as following a major system contingency, when the ISO may need to dispatch a large number of resources to increase output immediately – and counts on these resources to perform as dispatched in order to recover the Area Control Error within proscribed time limits (*e.g.*, 15 minutes). During these situations, a resource's marginal incentive to perform should reflect the importance of meeting this reliability standard. If the contingency is sufficiently large to deplete reserves, then assessing resource performance during these post-contingency conditions – for purposes of both Capacity Performance Payments and energy market payments – assures that resources that contribute to reliability the most at these times are rewarded for service they provide, and resources that do not deliver energy and reserves in these conditions are not. In keeping with the overall design objectives of Pay For Performance, resources are thereby compensated in accordance to what they provide during periods of heightened reliability risk.

B. Performance Measurement Reflects Contributions That Alleviate Scarcity Conditions

1. Actual Capacity Provided During a Capacity Scarcity Condition

Q: At a high-level, how is a resource's performance measured under Pay For Performance?

A: A resource's performance is assessed based on the energy and reserves it provides during a Capacity Scarcity Condition. In general, the measurement of energy and reserves for this purpose is the same as that used to compensate resource performance in the energy market. For demand resources, the measurement of resource performance is based on its reduction in energy consumption and, if applicable, any reserves it provides.

In the Tariff, the measure of resource performance during a Capacity Scarcity Condition is referred to as the resource's Actual Capacity Provided.[26] Note, importantly, that a resource does not need to have a Capacity Supply Obligation in order to perform and to receive Capacity Performance Payments. Thus, whether or not a particular resource has a Capacity Supply Obligation, its Actual Capacity Provided is calculated in the same way.

[26] *See* revised Tariff Section III.13.7.2.2.

The Pay For Performance design provides for a few adjustments in the measurement of Actual Capacity Provided of note, particular with respect to transmission limitations and external transactions. These I explain presently.

Q: If a generator's dispatch instruction is limited because of a transmission system limitation, can the generator increase its Capacity Performance Payment if it produces more energy than instructed?

A: No, it cannot. If a resource's dispatch instruction is limited by the transmission system's capability, the resource's Actual Capacity Provided is limited as well. This is provided for expressly in the Tariff. In this way, the design precludes a financial incentive for a resource to produce at a level that exceeds the transmission system's capabilities, at its location, during a scarcity condition.

Although the details differ, the effect of this treatment is similar to the effect of scarcity pricing in the energy market. In both cases, a resource whose dispatch is limited by a transmission constraint does not improve its profit by increasing its energy production above its dispatch point.

Q: **Please explain how performance is measured for Import Capacity Resources and external transactions generally.**

A: An Import Capacity Resource's performance is determined by the net energy delivered during the Capacity Scarcity Condition. For example, if a Market Participant with an Import Capacity Resource schedules a single external

transaction for 100 MW continuously all day into New England, and a Capacity Scarcity Condition occurs for one hour during the transaction, its Actual Capacity Provided would be 100 MWh for this event.

The reference to "net" energy delivered in the calculation of Actual Capacity Provided recognizes the possibility that a Market Participant may have both import and export external transactions during a Capacity Scarcity Condition. In this case, the import MWh and the export MWh during the scarcity condition are netted to determine the Market Participant's net import MWh. It is the Market Participant's net import MWh (but not less than zero) that is the basis for the Capacity Performance Payment. For example, if a Market Participant has a 50 MWh export external transaction and a 200 MWh import external transaction both scheduled during a Capacity Scarcity Condition, the Capacity Performance Payment will be based on Actual Capacity Provided equal to the net import of 200 MWh – 50 MWh = 150 MWh. This netting is performed at the participant level, across all external interfaces, to determine the performance eligible for Capacity Performance Payments.

Recall that, under Pay For Performance, a resource's performance is measured in the same way whether or not it has a Capacity Supply Obligation during the scarcity condition. Accordingly, if a Market Participant without an Import Capacity Resource schedules external transactions that flow during a Capacity Scarcity Condition, its Actual Capacity Provided will be determined in the same

way. That is, it is determined by the net import energy (but not less than zero) during the Capacity Scarcity Condition. Similarly as before, the netting is performed at the participant level, across all external interfaces, to determine the performance eligible for Capacity Performance Payments.

There are two reasons for this netting treatment of external transactions. The first is that it compensates a Market Participant based on the actual physical energy scheduled to be delivered *into* New England (if any) during the Capacity Scarcity Condition. To see why, suppose a Market Participant has a 50 MWh export external transaction and a 50 MWh import external transaction both scheduled during scarcity condition. The actual flow of power scheduled into New England to accommodate these two offsetting external transactions is, in fact, zero. In this situation, the Market Participant's two external transactions do not help alleviate the Capacity Scarcity Condition at all. Accordingly, the netting rule means that, in this situation, the Market Participant will receive a performance payment for its external transactions based on its net scheduled external transactions, which in this case is zero.

The second reason for the netting rule is to appropriately address wheeling transactions across the New England system that may continue to flow during a Capacity Scarcity Condition. Wheeling transactions simultaneously import power and export power, in equal amounts, across different external interfaces. They do not help resolve scarcity conditions, and for this reason their appropriate Capacity

Performance Payment is zero. The netting rule that applies to external transactions achieves this appropriate treatment.

There is an additional provision for capacity-backed exports *from* the New England system. This circumstance applies to generators within New England that are nominally serving load outside of the New England control area, through associated capacity-backed export external transactions (in the Tariff, these are called "External Transaction sales"). Because such a generator is not serving load in New England during the Capacity Scarcity Condition, the amount of its export is not credited to the applicable generating unit's Actual Capacity Provided.

Q: Does Pay For Performance require changes in how performance is assessed for demand response resources?

A: The way that performance is measured for demand response resources (including Real-Time Emergency Generation Resources) in the current FCM construct does not need to be changed in order to determine Capacity Performance Payments under Pay For Performance. In simple terms, they will continue to be assessed based on the reductions in load they achieve, and are eligible for Capacity Performance Payments in the same way as all other resources for their performance during Capacity Scarcity Conditions.

It is worth noting that, prior to the first Capacity Commitment Period (2018/2019) under Pay For Performance, the ISO plans to implement its Commission-

approved design to fully integrate demand response resources into the energy markets.[27] This means that, unlike today, there may be demand response resources that participate in the real-time energy and ancillary services markets without a Capacity Supply Obligation. Such a resource will be compensated for its performance (in the form of load reductions and, if applicable, reserves provided) during Capacity Scarcity Conditions at the Capacity Performance Payment Rate, consistent with the treatment of all resources under the Pay For Performance design.

Q: How do energy efficiency resources demonstrate performance?

A: In the Tariff, energy efficiency resources are included in the On Peak Demand Resource and Seasonal Peak Demand Resource categories. Currently, these resources demonstrate performance by submitting data to the ISO substantiating their energy load reduction (analogous to energy 'delivered' for a supply resource) during the peak hours as defined for each resource type. For an On Peak Demand Resource, for example, performance is the amount of energy load reduction it provides during defined on-peak hours, and zero in all other hours. In the Tariff, the Actual Capacity Provided of an energy efficiency resource during a Capacity Scarcity Condition is determined based on its average load reduction in

[27] *See ISO New England Inc*., 138 FERC ¶ 61,042 (2012) (accepting rules that fully integrate demand response resources (price-responsive demand or "PRD") into the energy market); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (accepting, in part, changes to the FCM rules to be consistent with the price-responsive demand fully integrated rules and accepting an effective date of June 1, 2017 for the fully integrated rules).

the applicable hour. For an On Peak Demand Resource or Seasonal Peak Demand Resource other than energy efficiency, the Actual Capacity Provided is determined based on its average output in the applicable hour.

Hence, for these resources, the timing of the Capacity Scarcity Condition will, to a large degree, affect the resource's performance measurement. A Capacity Scarcity Condition during low-load periods would, in general, occur when the amount of energy reduction or output from these resources is lowest (*e.g.*, zero). Conversely, a scarcity condition during a peak period occurs when these resources are likely to have their highest load reductions or output, leading to high performance.

Under Pay For Performance, every resource is eligible for Capacity Performance Payments, whether or not the resource has a Capacity Supply Obligation. This means that an energy efficiency resource that does not acquire a Capacity Supply Obligation will still be compensated for its performance. Its performance would be substantiated through compliance with the measurement and verification procedures applicable to comparable energy efficiency resources that do acquire a Capacity Supply Obligation. In addition, under the Pay For Performance design, if an energy efficiency resource with a Capacity Supply Obligation substantiates performance during hours other than peak periods, its performance during off-peak scarcity conditions would increase its Capacity Performance Payment as well. In other words, energy efficiency resources will be compensated for their

performance under Pay For Performance similarly to other resources in the system.

2. Capacity Balancing Ratio Measurement

Q: **How is the Capacity Balancing Ratio determined?**

A: Recall that the Capacity Balancing Ratio,[28] in concept, measures the system's load and reserve requirements relative to total Capacity Supply Obligations. In Section IV.C of this testimony, I explained the Capacity Balancing ratio using the following formula:

Capacity Balancing Ratio = (*Load* + *Reserve Requirement*) / *Total CSO MW*

The product of the Capacity Balancing Ratio and a resource's Capacity Supply Obligation MW determines the resource's share-of-system financial forward position and, when compared to its Actual Capacity Provided, its Capacity Performance Score.

To calculate the Capacity Balancing Ratio, the ISO does not directly measure the sum of consumers' electrical loads – at least, not at the retail point of

[28] *See* revised Tariff Section III.13.7.2.3.

consumption. Rather, the ISO determines the system's electrical load (including losses) based on measurement of total supply. Accordingly, in the Tariff, the numerator of the Capacity Balancing Ratio is determined, in part, from the same inputs used to determine Actual Capacity Provided.

Specifically, the load value appearing in the numerator of the Capacity Balancing Ratio is calculated as the sum of the Actual Capacity Provided, less the reserves supplied, for all resources during each interval of the Capacity Scarcity Condition. This appropriately accounts for the amount of 'load' served by demand-side resources at the time. The numerator in the Capacity Balancing Ratio is determined by adding to this sum the applicable reserve requirement value at the time.

Q: Do the reserve requirements used in the Capacity Balancing Ratio depend on the type of reserve requirement that is violated during a Capacity Scarcity Condition?

A: Yes. The value of the reserve requirement in the Capacity Balancing Ratio reflects the required amounts of the types of reserves that can help alleviate the Capacity Scarcity Condition. For example, if the system dispatch software indicates a deficiency in the system minimum 30-minute reserve requirement (*i.e.*, offline or online generation capability available in 30 minutes or less), then the reserve requirement in the Capacity Balancing Ratio includes the required levels of 10-minute reserves and 30-minute reserves. This is because 10-minute capable

reserves can substitute for, and contribute to, the 30-minute reserve needs. However, if the system dispatch software indicates a deficiency in the system 10-minute reserve requirement, but not a deficiency in the 30-minute reserve requirement, then the reserve requirement in the Capacity Balancing Ratio includes the required levels of 10-minute reserves, but not the required levels of 30-minute reserves (as the latter do not help alleviate the Capacity Scarcity Condition, and are in sufficient supply, in this situation).

If the system dispatch software indicates a reserve deficiency in a Capacity Zone, but not in the system overall, then the calculation uses zonal-level information to provide a Capacity Balancing Ratio applicable the resources in the relevant Capacity Zone.

Q: Please explain further. If a scarcity condition occurs in a Capacity Zone, but not in the system overall, how is the Capacity Balancing Ratio calculated differently?

A: At a high level, the Capacity Balancing Ratio is determined similarly whether the scarcity condition occurs at the system level or at a zonal level. In particular, if the scarcity condition occurs in a Capacity Zone, but not in the system overall, the Actual Capacity Provided is determined from the resources in that Capacity Zone. Similarly, the reserve requirement value is based on the zonal, not the system-level, reserve requirement.

There are two additional adjustments made when a scarcity condition occurs in a Capacity Zone (but not in the system overall). First, for the measure of load in the numerator of the Capacity Balancing Ratio, which is determined from Actual Capacity Provided within the Capacity Zone, we must add in the load served by energy flowing into the Capacity Zone across an external interface. In the Tariff, there is an adjustment for the net amount of energy imported directly into the Capacity Zone from outside the New England Control Area in this situation.

Second, during a scarcity condition in a zone, part of the reserve requirement in the zone is generally supplied through the unloaded portion of the internal transmission interfaces into the zone. The amount of the Capacity Zone's reserve requirement satisfied through reserve support across these internal interfaces is subtracted from the zonal reserve requirement in the numerator of the Capacity Balancing Ratio. In this way, the Capacity Balancing Ratio reflects the reserves that are required from resources *inside* the Capacity Zone at the time. In the Tariff, there is an adjustment that subtracts the reserve support coming into the Capacity Zone over the internal transmission interface in this situation.

This treatment means that a resource located in a Capacity Zone experiencing a zonal scarcity condition, at a time when the system as a whole is not in a scarcity condition, has its performance evaluated relative to its share of the *zone's* energy and reserve requirements, rather than its share of the system's requirements (which are not experiencing a scarcity condition at the time).

Q: Are there different Capacity Balancing Ratios applicable if there is a simultaneous violation of a system-level and a zonal reserve requirement?

A: Yes. Resources located in a Capacity Zone that is deficient its zonal reserve requirement have Capacity Performance Scores calculated using the zonal Capacity Balancing Ratio, as described in my preceding response. Resources outside the Capacity Zone(s) that are deficient their zonal requirements (*i.e.,* the resources located in the rest of the system) have Capacity Performance Scores calculated using the system-level Capacity Balancing Ratio.

In this way, a resource located in a Capacity Zone experiencing a zonal scarcity condition remains evaluated relative to its share of the zone's energy and reserve requirements. A resource in the rest-of-system has its performance evaluated relative to its share of the system's requirements (which are also experiencing a scarcity condition at the time).

In the Tariff, this treatment is delineated by whether or not there is scarcity pricing in a Capacity Zone based on a deficiency of the *local* Thirty-Minute Operating Reserves requirement. If so, the resources in that zone have the zonal Capacity Balancing Ratio calculation. If not, they are located in the rest-of-system, and have the system-wide Capacity Balancing Ratio calculation.

Q: Can the Capacity Balancing Ratio exceed 100 percent?

A: Yes, that is possible, in theory. To see why, recall that the FCM procures an Installed Capacity Requirement designed to meet the 1-event-in-10-years resource adequacy criterion (as noted earlier in this testimony in Section III.A). This means that, as a matter of statistics, it is possible that New England could experience a future peak load level sufficiently high that it (plus the reserve requirement) could exceed the total of all Capacity Supply Obligations on the system.

If the Capacity Balancing Ratio exceeds 100 percent for an interval, then even a capacity resource that performs exactly at its Capacity Supply Obligation MW would receive a negative Capacity Performance Payment for the interval. That is because under Pay For Performance, resources are accepting a share-of-system requirements financial performance obligation – even if the system's energy and reserve requirements during scarcity conditions turn out to be higher, or lower, than expected over the course of the Capacity Commitment Period.

If a supplier views the likelihood of the Capacity Balancing Ratio exceeding 100 percent to be material, this possibility should be factored into its capacity offer price in the Forward Capacity Auction. To determine a competitive capacity offer price, any capacity resource should calculate its annual expected Capacity Performance Payment (as explained, in greater detail, in the examples provided earlier in this testimony in Section VI.A). The possibility of a negative Capacity Performance Payment due to a Capacity Balancing Ratio in excess of 100 percent,

if it is material, simply becomes part of that financial calculation to determine a resource's capacity offer price.

C. Capacity Performance Bilaterals

Q: What is a Capacity Performance Bilateral?

A: A Capacity Performance Bilateral is a financial transaction between two resource owners. In a Capacity Performance Bilateral, a resource that performs above its share of the system's requirements during a scarcity condition agrees to transfer (some or all of) its positive Performance Score to the benefit of another resource.[29] The principal purpose of this type of transaction is to enable a capacity supplier to reduce its financial exposure to negative Capacity Performance Payments during a period when it may expect to perform poorly.

Q: How does it work?

A: The concept is simple, and easily explained by example. Imagine that one resource owner expects to perform well during scarcity conditions, and another resource owner's unit is out of service. A one-hour scarcity condition occurs during the month. Assume Resource S ('S' is for Seller) performs well, and has a positive deviation from its share of system requirements (a positive Capacity

[29] *See* revised Tariff Section III.13.5.3.

Performance Score) of +100 MWh. Resource B ('B' is for Buyer) is out of service, and has a negative deviation from its share of system requirements (a negative Capacity Performance Score) of –60 MWh.

For purposes of this example only, assume the Capacity Performance Payment Rate is $2,000 per MWh. We can calculate each resource owner's Capacity Performance Payment as the product of its Capacity Performance Score and the Capacity Performance Payment Rate:

Capacity Performance Payment to S = +100 MWh × $2,000 per MWh = $200,000

Capacity Performance Payment to B = –60 MWh × $2,000 per MWh = –$120,000

Now suppose that the two parties agree to a Capacity Performance Bilateral. Specifically, assume their Capacity Performance Bilateral is an agreement to transfer 60 MWh of Resource S's Capacity Performance Score to Resource B. Once the two parties submit the Capacity Performance Bilateral to the ISO, the ISO adjusts each resource's Capacity Performance Score and Capacity Performance Payment accordingly. With a Capacity Performance Bilateral for 60 MWh, the seller is debited 60 MWh of its Capacity Performance Score and the

buyer is credited 60 MWh of Capacity Performance Score. This results in adjusted Capacity Performance Payments, as follows:

Capacity Performance Payment to S = (+100 – 60) MWh × $2,000 per MWh = $80,000

Capacity Performance Payment to B = (– 60 + 60) MWh × $2,000 per MWh = $0

The buyer no longer has a negative Capacity Performance Payment, in this example.

Q: Why would a resource owner use a Capacity Performance Bilateral?

A: From an economic perspective, there is little purpose in the two parties agreeing to a Capacity Performance Bilateral *after* a scarcity condition occurs. Rather, a Capacity Performance Bilateral creates economic value to the transacting parties if it is arranged before a Capacity Scarcity Condition occurs. There are two reasons why the transacting parties may find it valuable to enter into a Capacity Performance Bilateral:

- Differences in their expectations about the number of scarcity hours that will occur during a specified period of time; and

- risk aversion with respect to potential negative Capacity Performance Payments during a period when a supplier expects its resource may perform poorly.

For example, a resource owner that plans to take a two-week maintenance outage of its resource may wish to enter into a Capacity Performance Bilateral, as a buyer, to reduce the potential for negative Capacity Performance Payments if scarcity conditions occur while the unit is out of service. In this way, a Capacity Performance Bilateral is a simple means for it to manage non-performance risk: In effect, it is acquiring (a degree of) financial insurance against the possibility, and the magnitude, of a negative Capacity Performance Payment while it is out of service.

Note that, in consideration of the transfer of Capacity Performance Score from the seller to the buyer under a Capacity Performance Bilateral, the seller would be remunerated by the buyer. The terms of this remuneration are arranged between the parties to the Capacity Performance Bilateral, and this component of the bilateral transaction is not settled (nor observed) by the ISO.

Q: Why might a resource owner enter into a Capacity Performance Bilateral, instead of shedding its Capacity Supply Obligation entirely for the period it is out of service?

A: The shortest timeframe for which a resource can assume or shed a Capacity Supply Obligation is an entire month. There are monthly Capacity Supply Obligation bilateral transactions and monthly reconfiguration auctions. It is plausible that Market Participants may seek to shed a Capacity Supply Obligation when it is known prospectively that the resource will (or may) be out of service (or perform poorly) for much of the month. For example, a participant that plans to conduct a four-week maintenance outage may shed the resource's Capacity Supply Obligation during the month affected. By shedding the Capacity Supply Obligation the resource would avoid any possibility of a negative Capacity Performance Payment should scarcity conditions occur during the month.

Of course, not all outages can be anticipated, and not all periods in which a resource may have poor performance last for a month. Capacity Performance Bilaterals are a highly flexible instrument that enables a resource owner to mitigate the risk of negative Capacity Performance Payment during periods shorter than a month, or on shorter notice than a Capacity Supply Obligation can be shed. A Capacity Performance Bilateral will adjust a resource's Capacity Performance Score during a scarcity condition, without affecting either resource's Capacity Supply Obligation.

Q: Are there restrictions on the types of resources that may enter into a Capacity Performance Bilateral?

A: Under Pay For Performance there is no need, nor reason, to exclude any resource type from entering into a Capacity Performance Bilateral. Nor are any zonal restrictions necessary, other than that the two resources must be subject to the same Capacity Scarcity Condition. This is because a Capacity Performance Bilateral transfers credit for demonstrated performance, above the transferring resource's share of the system's requirements, which substitutes for the same MWh of performance not provided by the receiving resource (during the same Capacity Scarcity Condition).

Note that if a resource is in a Capacity Zone that is not experiencing a scarcity condition, it would not have any Capacity Performance Score to transfer. Resources can only transfer positive Capacity Performance Scores.

Q: How does a Capacity Performance Bilateral fit within the set of ISO-administered processes with which a capacity resource can cover its financial performance obligation under Pay For Performance?

A: Capacity Performance Bilaterals fit within a range of ISO-facilitated transactions that can help a Market Participant with a Capacity Supply Obligation to manage its non-performance risk. These span a range of different time horizons. For instance:

- Prior to the Capacity Commitment Period, a resource owner that learns its resource may perform more poorly than anticipated can shed its Capacity Supply Obligation, either in an annual reconfiguration auction or bilaterally;

- during the Capacity Commitment Period, on a monthly basis, a supplier whose resource may be out of service, or that may perform poorly for any other reason, can shed its Capacity Supply Obligation in a monthly reconfiguration auction or bilaterally;

- within the month prior to a Capacity Scarcity Condition, a supplier whose resource may perform poorly can cover its financial performance obligation (in whole or in part) by entering into a Capacity Performance Bilateral with a bilaterally-arranged counter-party.

Last, during a Capacity Scarcity Condition, a resource that performs poorly covers its financial performance obligation through the Pay For Performance two-settlement system. As I explained in Section IV.B earlier in this testimony, it covers its under-performance with purchases, at the Capacity Performance Payment Rate, from suppliers that over-perform at the same time.

In sum, Capacity Performance Bilaterals provide a highly flexible means for participants to manage potential non-performance risk, and fit within a range of mechanisms with which a supplier can cover a resource's financial performance obligation under Pay For Performance.

D. Peak Energy Rent and Import Capacity Offer Price Thresholds

1. Applicability Of The Peak Energy Rent Deduction

Q: How does the Peak Energy Rent deduction of the FCM change with Pay For Performance?

A: The existing Peak Energy Rent provisions of the FCM deduct a portion of each capacity resource's monthly payment if, during the month, the real-time energy price exceeds a specified threshold price.[30] The design intent of this Peak Energy Rent deduction is to provide a disincentive for a pivotal supplier in the Real-Time Energy Market to physically withhold supply during tight market conditions, and thereby increase the energy price paid to its other resources at the time.

The Pay For Performance design does not change, as a substantive matter, the function or design of the Peak Energy Rent deduction of the FCM. That is, the Peak Energy Rent deduction will continue to apply, in the same way as today, if the real-time energy price exceeds the specified threshold price.

Q: You explained earlier, in Section VI.A, that the Capacity Performance Payment Rate plays the role of a scarcity price premium to the energy market's scarcity price. Given that, should the Capacity Performance Payment be counted as part of a resource's Peak Energy Rent?

A: No. The revenue that a resource receives in the form of Capacity Performance Payments is not included in the calculation of the Peak Energy Rent. To do so would eviscerate the performance incentives that Pay For Performance is

[30] *See* revised Tariff Section III.13.7.1.2.

designed to provide. The effect would be to increase the Peak Energy Rent deduction as the resource's Capacity Performance Payments increase. If the positive Capacity Performance Payments that are earned by good-performing resources were then removed from the resource's net FCM revenue each month, the incentive disappears. This is not consistent with the design objectives of Pay For Performance.

At a more sophisticated level, the two-settlement nature of the Pay For Performance design intrinsically provides incentives for competitive behavior in the capacity market, similar to the role played by the existing Peak Energy Rent deduction in the Real-Time Energy Market. To see this, it helps to consider the economic structure of the Peak Energy Rent provisions in more detail.

From an economic perspective, the Peak Energy Rent provisions of the FCM are structured as a financial call option on the real-time energy price. Stated in simplest possible terms, a capacity resource receives a financial charge in FCM settlement equal to a *portion* of the scarcity revenue that it earns in the energy market during tight market conditions. The portion is based, approximately, on the resource's pro-rata share of system's energy requirements at the time. (In the Peak Energy Rent provisions of the Tariff, this portion is determined by a term called the Scaling Factor, which plays a role in the Peak Energy Rent provisions that is analogous to the Capacity Balancing Ratio under Pay for Performance.) In this way, under the Peak Energy Rent, a resource retains the Real-Time Energy

Market's scarcity revenue only if its performance exceeds its share of the system's requirements during scarcity conditions.

A similar effect is achieved with respect to the additional scarcity revenue that the capacity market provides under the Pay For Performance design. Specifically, a capacity resource is subject to a financial charge in FCM settlement, in the form of a negative Capacity Performance Payment, if it performs below its share of the system's requirements during scarcity conditions. In this way, under Pay For Performance, a resource retains the capacity market's scarcity revenue only if its performance exceeds its share of the system's requirements during scarcity conditions.

Taken together, the Peak Energy Rent deduction and the Pay For Performance design provide powerful *dis*incentives for a resource intentionally to exhibit poor performance (that is, for a resource to withhold its supply) during scarcity conditions. However, while these disincentives are structured similarly, they are not strictly duplicative of one another. Accordingly, Pay For Performance does not remove the existing Peak Energy Rent provisions of the FCM. Moreover, for all of the reasons explained above, a resource's Capacity Performance Payments will not be subject to subsequent deduction under the Peak Energy Rent provisions of the FCM.

2. Import Capacity Resource Offer Obligations

Q: How do Import Capacity Resources' offer obligations change under Pay For Performance?

A: Generally, an Import Capacity Resource with a Capacity Supply Obligation must offer energy associated with the resource into the Day-Ahead Energy Market and Real-Time Energy Market as one or more External Transactions. Presently, these energy offers must be at, or below, an administratively-determined daily offer price threshold. Pay For Performance makes the requirement for Import Capacity Resources to offer energy at, or below, this daily offer price threshold economically unnecessary. Accordingly, this unnecessary administrative requirement is being removed from the Tariff.[31]

The intent of the requirement for Import Capacity Resources to offer at, or below, an administrative daily offer price threshold is to ensure the ISO can dispatch the energy associated with the resource during scarcity conditions. At the time this requirement was implemented, the ISO's scarcity price adders in the energy market were much lower than today, and the system experienced energy prices during scarcity conditions well below $1,000 per MWh (the value of the energy market's offer price cap). As a result, if an Import Capacity Resource offered into the Real-Time Energy Market an external transaction below the energy market's offer price cap, but at a higher offer price than the prevailing energy price during

[31] *See* revised Tariff Section III.13.6.1.2.1.

the scarcity condition, the external transaction could not be economically dispatched. By requiring external transactions associated with Import Capacity Resources to offer at, or below, a much lower administrative daily offer price threshold, the ISO was able to ensure it could economically dispatch the external transactions associated with an Import Capacity Resource during scarcity conditions.

Under Pay For Performance, this same objective is achieved in a simpler manner. During any scarcity condition, an Import Capacity Resource faces a marginal incentive to deliver energy that equals the sum of the energy market's real-time price plus the Capacity Performance Payment Rate, less the price of energy in the neighboring Control Area that is the source of the import. This marginal incentive is likely to exceed the Capacity Performance Payment Rate of $2,000 per MWh during the phase-in period, and to exceed $5,000 after the Full PPR takes effect. These marginal incentives are much stronger than the incentives that exist under today's administrative daily offer requirement for Import Capacity Resources.

Given the magnitude and applicability of the marginal incentives under Pay For Performance, for purposes of assuring that an Import Capacity Resource's energy will be accessible and delivered into the New England system during scarcity conditions, the existing administrative daily offer requirement becomes moot.

Accordingly, under Pay For Performance, this unnecessary administrative requirement is being removed.

VIII. STOP-LOSS PROVISIONS OF THE PAY FOR PERFORMANCE DESIGN

Q: What is a stop-loss limit?

A: Under the Pay For Performance design, it is possible for a capacity resource to incur a negative Capacity Performance Payment that exceeds its Capacity Base Payment. In that circumstance, the resource incurs a net financial loss in capacity market settlement. The Pay For Performance design includes provisions that limit a capacity supplier's potential net financial losses. I will refer to this limit as a "stop-loss limit," and the associated design elements as the "stop-loss mechanism."[32]

The Pay For Performance design includes both monthly and annual stop-loss limits.

Q: What is the purpose of the stop-loss mechanism?

A: Under the Pay For Performance design, a resource may incur a net financial loss in the FCM settlement if its performance is sufficiently poor, relative to its share

[32] *See* revised Tariff Section III.13.7.3.

of the system's requirement, in a month with a sufficiently high number of scarcity hours. As I explained in Section III.B.3 in this testimony, this potential for a capacity resource to have a net loss on its forward financial position in the capacity market plays an economically important role in solving the existing FCM's free option problem.

Nonetheless, it is not commercially reasonable for a capacity supplier to face potentially unlimited losses for non-performance. Accordingly, the Pay For Performance design includes the stop-loss mechanisms to limit a capacity supplier's potential loss exposure in the capacity market settlement.

A. A High-Level Explanation Of The Stop-Loss Mechanism And Its Design Principles

1. Design Principles

Q: What are the central design principles of the stop-loss mechanism?

A: The stop-loss mechanism design is guided by four central principles. These are: (1) simplicity, (2) transparency, (3) incentive distortions should be minimized, and (4) loss-limit events should occur infrequently. The stop-loss mechanism of the Pay For Performance design represents a balanced trade-off among these design principles.

Q: Please explain the first principle – simplicity – and why it is important.

A: Simplicity allows market participants to understand readily how the stop-loss mechanism works. This enables it to serve its intended purpose well as a means to limit a supplier's maximum exposure to financial loss in the capacity market. Simplicity helps a supplier to incorporate the risk-reducing role of the stop-loss mechanism into quantitative risk models and prospective financial calculations, facilitating the evaluation of its financial risk of poor performance.

In addition, keeping the stop-loss mechanism simple helps to minimize potentially complex tracking and assignment issues when suppliers trade Capacity Supply Obligations among one another, and provides clarity to market participants regarding how stop-loss limits apply when bilateral trades are contemplated.

Q: Please explain the second principle -- transparency – and why it is important in a stop-loss design.

A: Transparency enables a potential capacity supplier to know its maximum loss exposure *prior to* its participation in the Forward Capacity Auction. This enables the supplier to account for its maximum loss exposure when preparing its capacity supply offer in each auction. In addition, transparency enables a potential capacity supplier to communicate its maximum loss exposure to third parties with which it may do business, such as external entities providing financing to a capacity resource, prior to the decision to acquire a Capacity Supply Obligation.

Q: Please explain the third principle – why is it important that the stop-loss mechanism minimize incentive distortions?

A: Any stop-loss mechanism has the potential to attenuate a capacity supplier's incentive to perform (or invest to improve future performance), once a resource has reached (or expects to reach) the stop-loss limit.

Of particular concern is that the stop-loss limit presents an alternative to investing in tangible resource improvements or operating practices that would reduce poor performance. If the stop-loss limit is set so there is a small maximum loss, then simply paying that limited performance charge may be a more financially attractive option than undertaking operational-related investments to improve resource performance. This undermines the Pay For Performance design, which is based on the principle that resources should be paid for the energy (or reserves) they deliver during scarcity conditions.

A well-designed mechanism should minimally distort a supplier's incentives (a) to perform during scarcity events, and (b) to trade-out or replace a non-performing capacity resource during periods when it expects to perform poorly.

Q: Please explain the fourth principle -- why must loss-limit events occur infrequently?

A: The stop-loss limit also imposes costs on other capacity suppliers, who may receive lower FCM revenue to ensure that performance payments balance across

the pool. I explain this in greater detail below. In addition, a frequently-reached stop-loss limit also weakens the incentives of poorly-performing resources to make investments that improve performance, which would adversely affect the capacity market's ability to achieve the region's reliability objectives.

2. Economic Framework of the Stop-Loss Mechanism: Mutual Insurance Among Capacity Suppliers

Q: At a high-level, what is the conceptual logic of the stop-loss mechanism?

A: Conceptually, the stop-loss mechanism is a mutual insurance system among all resources with a Capacity Supply Obligation. Each capacity supplier receives insurance against the possibility of a large negative Capacity Performance Payment – that is, in excess of the stop-loss limit – in the event that its capacity resource performs poorly in a month with many scarcity hours.

The set of all capacity resources eligible to receive this insurance benefit also pay for it. Specifically, if one (or more) capacity resources reaches the stop-loss limit, the other capacity resources in the pool will receive reduced net FCM payments. In effect, capacity suppliers are insuring one another, in part, against the adverse financial consequences of very poor resource performance.

Q: How does that work in relation to the two-settlement design of Pay For Performance?

A: Under the two-settlement Pay For Performance design, a resource that performs worse than its share-of-system requirement during scarcity conditions has a negative Capacity Performance Score. This results in a negative Capacity Performance Payment for the resource. The stop-loss mechanism limits the magnitude of the resource's negative performance payment.

When this occurs, it affects the net surplus that results from settlement of all Capacity Performance Payments across the pool. This net surplus is described in Section IV.D earlier in this testimony. Specifically, without a stop-loss mechanism, the Pay For Performance design results in a net surplus each time scarcity conditions occur. There is a net surplus because the total amount of resource under-performance (in MW) exceeds the total amount of resource over-performance (in MW) during any scarcity condition (if this were not the case, there would have been no scarcity condition).

As part of the stop-loss mechanism design, the net surplus that accrues each Obligation Month will be allocated among the pool of capacity suppliers. However, if there is a capacity resource with sufficiently poor performance that its negative Capacity Performance Payment reaches the stop-loss limit, that fact will decrease the net surplus that remains to be shared with all other capacity suppliers. In this way, if one (or more) capacity resources reaches the stop-loss limit, other capacity suppliers will receive reduced net FCM payments.

This is a very simple mutual insurance system. Moreover, it ensures that all FCM performance payments balance across the pool of all suppliers.

Q: Can you provide a simple example that illustrates this concept?

A: Let's consider an example that I used earlier in my testimony, which appears in Section IV.D on pages 83-84. I will use that example to illustrate how a stop-loss limit reduces the net surplus and, as a result, reduces the final payments to capacity suppliers that do not reach the stop-loss limit.

In that example, there was one scarcity condition during a month. Unit A performed below its share of system requirement and incurred a negative Capacity Performance Payment of –$336,000. This is greater (in magnitude) than the positive Capacity Performance Payments of Units B and C, which are +$128,000 each. The settlement of all Capacity Performance Payments in that example yields a net surplus of $80,000, calculated as: $336,000 – ($128,000 + $128,000).

Now let's consider how a stop-loss limit changes this net surplus. The stop-loss mechanism limits a resource's negative Capacity Performance Payment if, and only if, its value reaches (in magnitude) the stop-loss limit. For purposes of the present example only, assume that the stop-loss limit applicable to unit A is $280,000. That means Unit A's negative Capacity Performance Payment will be limited to –$280,000, instead of being charged a negative Capacity Performance Payment of $336,000 in the FCM settlement.

This reduces the net surplus. Units B and C still have positive Capacity Performance Payments of +$128,000 each. Unit A has a negative Capacity Performance Payment limited by the stop-loss to –$280,000. The net surplus when all Capacity Performance Payments are settled across the pool is then $24,000, calculated as $280,000 – ($128,000 + $128,000). This net surplus is less than the $80,000 net surplus in the example without the stop-loss mechanism.

Q: How is the net surplus allocated?

A: Each Obligation Month, the net surplus from the settlement of all Capacity Performance Payments is allocated, on a Capacity Supply Obligation pro-rata basis, to capacity suppliers that did not reach the stop-loss limit.

In the context of the previous example, both Unit B and Unit C have the same Capacity Supply Obligation of 80 MW each. This means they will receive an equal allocation of the net surplus at the end of the Obligation month. With the stop-loss limit, the net surplus is $24,000, and so their allocation of the net surplus is $12,000 each.

Note that, in the example *without* the stop-loss limit, the net surplus is $80,000, and Units B and C would receive larger allocation of the net surplus. To see this, recall that the total capacity of all three suppliers in this example is 300 MW. Thus, in the case without a stop-loss, a pro-rata allocation of the net surplus would allocate to B and to C each a pro-rata share equal to (80 MW / 300 MW) = 26.33% of the total net surplus, or $21,333, calculated as 26.33% of $80,000. In

sum, *without* the stop-loss limit, Unit B and Unit C's allocation of the net surplus would have been $21,333 each. This is more than their allocation of $12,000 each with the stop-loss. In general, in this way, if a capacity resource reaches the stop-loss limit, the other capacity suppliers will receive reduced net FCM payments.

There are two important features to note about this simple example. First, FCM performance payments balance, exactly, across the pool of capacity suppliers. The net surplus after settlement of all Capacity Performance Payments is allocated back to capacity suppliers.

Second, the net surplus will be lower if one (or more) capacity supplier's Capacity Performance Payments reach the stop-loss limit. This reduces the amount to be shared among all capacity suppliers after all Capacity Performance Payments are settled each month. In that sense, capacity suppliers are insuring one another, in part, against the adverse financial consequences if one of them experiences very poor resource performance. Each capacity supplier receives financial protection against the possibility of an excessively negative Capacity Performance Payment – that is, in excess of the stop-loss limit – in the event that its capacity resource performs poorly in a month with many scarcity hours. The other capacity suppliers share in the allocation of this risk, in the sense that if this occurs, they receive a lower allocation of the net surplus.

Q: Is it possible for the net surplus to be negative due to the stop-loss mechanism?

A: Yes, that is possible. If there are a large number of capacity suppliers that perform very poorly in a month with many scarcity hours, it is possible that application of the stop-loss limit will produce a negative net surplus (that is, a net deficiency). In this case, each capacity supplier that does not reach the stop-loss limit will still be allocated a pro-rata share of the negative net surplus.

For example, imagine that in the preceding example we changed the stop-loss limit applicable to unit A. Specifically, instead of assuming a stop-loss limit of $280,000, suppose we assume a stop-loss limit of only $250,000. In that case, Unit A's negative Capacity Performance Payment is limited to –$250,000. The net surplus when all Capacity Performance Payments are settled across the pool is then –$6,000, calculated as $250,000 – ($128,000 + $128,000). As before, the net surplus (here, a deficiency) of –$6,000 is allocated on a Capacity Supply Obligation pro-rata basis to the units that do not reach the stop-loss limit. This means that Units B and C share in the net surplus allocation at the end of the obligation month in the form of a charge of –$3,000 each.

Because of the possibility that the net surplus to be allocated at the end of an Obligation Month may be either positive or negative, in the Tariff this allocation

is referred to as the "Allocation of Deficient or Excess Capacity Performance Payments."[33]

Q: Conceptually, how is that like mutual insurance?

A: Whether the net surplus is positive or negative, the stop-loss design amounts to a mutual insurance system among an 'insured pool' of all capacity suppliers. Each capacity supplier is protected, financially, against extreme losses if its resource performs very poorly during a month with many hours of scarcity conditions. This protection is likely to be most important if a capacity resource is out of service during a period when significant scarcity conditions occur, and the resource did not trade its Capacity Supply Obligation to another resource (or otherwise cover its share-of-system obligation).

In this context, there is no pre-specified insurance premium assessed to participants in this insurance pool. Instead, the net surplus plays the role of the financial reserves available to cover insured losses. Like insurance generally, the net surplus may be greater than the 'insured losses' incurred by poorly performing resources, if no (or few) capacity resources losses exceed the stop-loss limit. This is the case when the net surplus is positive. In this situation, the net surplus that remains is returned to the other capacity suppliers in the insurance pool.

[33] *See* Tariff Section III.13.7.4.

This distribution is precisely analogous the conventional mutual insurance dividend in a mutual insurance system. The conventional mutual insurance dividend is a variable amount that is returned to the mutually-insured parties if – and only if – covered losses are less than the surplus premiums.

Also like insurance generally, the net surplus is not guaranteed to cover total 'insured losses' if there are many poorly performing resources in a period with many scarcity hours. This is the case when the net surplus is negative. The stop-loss mechanism then reduces the net FCM payments to all other capacity suppliers in the pool, on a pro-rata basis, to offset the 'stopped' losses incurred by poorly performing capacity resources. This is analogous to a mutual insurance practice of increasing the financial reserves after the fact (via additional levies on the insurance pool members) after a period of excessive insured losses.

In these respects, the stop-loss mechanism design is not a novel concept. Rather, it is modeled on the key elements of a risk-sharing, or mutual insurance, system among a pool of unaffiliated commercial entities that face similar, but imperfectly correlated, verifiable loss events.

Q: Do resources without a Capacity Supply Obligation participate in the stop-loss mechanism?

A: Only resources with a Capacity Supply Obligation participate in the stop-loss mechanism. This is not a stop-loss design decision per se, but rather a direct

consequence of the Pay For Performance two-settlement design overall. Specifically, a resource without a Capacity Supply Obligation cannot incur financial losses in the capacity market because it does not have a share-of-system financial performance obligation. It receives no Capacity Base Payment, and cannot receive a negative Capacity Performance Payment.

This means a resource without a Capacity Supply Obligation has no potential financial losses in FCM settlement, and nothing to 'insure' through the stop-loss mechanism. Accordingly, these resources do not have stop-loss limits, and are not included in the allocation of the net surplus (whether positive or negative).

B. The Monthly Stop-Loss Limit

Q: Over what time periods are a capacity resource's losses limited by the stop-loss mechanism?

A: The stop-loss mechanism has two separate stop-loss limits, which apply to different time periods. One limits a resource's net financial losses in each month of the commitment period. The other further limits a resource's net financial losses over the entire annual commitment period (which runs from the beginning of June until the end of the following May).

The monthly stop-loss limit and the annual stop-loss limit are applied separately. That means a resource that has reached *either* the monthly stop-loss limit, or the

annual stop-loss limit, will have its negative Capacity Performance Payment limited by the binding stop-loss limit in an Obligation Month.

I will discuss the monthly stop-loss limit next, and the annual stop-loss limit in Section VIII.C subsequently.

Q: What is the monthly stop-loss limit?

A: The monthly stop-loss limit caps a resource's Capacity Performance Payment, if negative, to an amount equal to the product of its Capacity Supply Obligation MW and the applicable Forward Capacity Auction Starting Price.[34]

For example, assume a capacity resource has a 10 MW Capacity Supply Obligation, and that the Forward Capacity Auction Starting Price is $15,000 per MW-month. This resource will have a monthly stop loss limit of $150,000, calculated as $15,000 per MW-month × 10 MW = $150,000 per month.

Q: Why is this monthly stop-loss limit reasonable?

A: This monthly stop-loss limit is consistent with the four stop-loss design principles listed previously, each of which is consistent with the overall Pay For Performance design. These properties are (1) simplicity, (2) transparency, (3) the

[34] *See* revised Section III.13.7.3.1.

economic incentives of the Pay for Performance design are maintained, and (4) loss-limit events should occur infrequently. In addition, this monthly stop-loss limit is consistent with a capacity resource's maximum potential net loss under other Tariff provisions that are not being changed with Pay For Performance, and that the Commission has previously found to be reasonable. I will discuss each of these points in turn.

Q: Please explain why the monthly stop-loss limit satisfies the first principle – simplicity?

A: The monthly stop-loss limit caps a resource's Capacity Performance Payment based on the product of its Capacity Supply Obligation MW and the Forward Capacity Auction Starting Price (which is $15,819 per MW-month for the upcoming eighth Forward Capacity Auction), regardless of the Capacity Base Payment. This monthly stop-loss limit value can be easily calculated by market participants prior to the auction and incorporated into their valuation of a Capacity Supply Obligation.

Q: Please explain why the monthly stop-loss limit satisfies the second principle – transparency?

A: The monthly stop-loss limit ensures that a resource can determine, based on the price of its capacity offer, the maximum net loss exposure it may face each month under Pay For Performance. This means it can account for, and thereby limit, its maximum monthly net loss based on its capacity offer price.

If the Capacity Clearing Price is greater than the resource's capacity offer price, the resource will clear in the Forward Capacity Auction. In this case, its maximum monthly net loss, on a per Capacity Supply Obligation MW basis, equals the difference between the Capacity Clearing Price and the Forward Capacity Auction Starting Price. This difference is smaller than the difference between the resource's capacity offer price and the Forward Capacity Auction Starting Price – both of which are known quantities to the resource prior to the Forward Capacity Auction.

In this way, the resource's maximum monthly loss exposure under Pay For Performance is known to the resource owner prior to the Forward Capacity Auction.

Q: Please explain why the monthly stop-loss limit satisfies the third principle – the economic incentives of Pay For Performance are maintained?

A: The most important reason is that it is reasonable to anticipate that resources will reach the monthly stop-loss limit infrequently. This indicates that, with infrequent exception, a resource's incentive to perform is not affected by the monthly stop-loss limit.

In addition, two other important features of the Pay For Performance design should result in the monthly stop-loss limit being reached infrequently. These are the ability of a resource to cover its obligation through a bilateral transaction with

another market participant, either through the new Performance Score Bilateral mechanism (*see* Section VII.C) or through a trade of the Capacity Supply Obligation to another resource. Resources that expect to have zero performance have an incentive to arrange such transactions at a cost to them of (at most) the Forward Capacity Auction Starting Price if they expect a high number of scarcity hours during, say, a summer month.

Moreover, a resource that performs at zero for many scarcity hours early in a month may not reach the stop-loss limit by the end of the month, if its performance improves during later scarcity conditions. That is, a resource can "come back above" the stop-loss limit through good performance. This preserves incentives to perform even in the presence of the stop-loss limit. I discuss this property in greater detail further below.

Q: Please explain why the monthly stop-loss limit satisfies the fourth principle – that loss-limiting events should occur infrequently?

A: The monthly stop-loss limit is set sufficiently high so that even poorly performing resources are likely to reach this limit infrequently.

This can be seen by considering how many hours of scarcity conditions in a month are necessary for a resource that performs poorly to reach the monthly stop-loss limit. The following calculation here is informative, which considers the case of a resource with zero performance.

The number of scarcity hours until a resource's Capacity Performance Payment reaches the monthly stop-loss limit depends on a number of factors, including the Capacity Performance Payment Rate, the Forward Capacity Auction Starting Price, the resource's average performance, and the average Capacity Balancing Ratio. Assume, for purposes of this calculation only, the Full PPR value of $5,455 per MWh, a Forward Capacity Auction Starting Price of $15,000 per MW-month, and an average Capacity Balancing Ratio of 0.75. The Capacity Performance Payment for a 1 MW Capacity Supply Obligation resource with zero performance is:

Capacity Performance Payment = $5,455 × [0 – 0.75 × 1 MW] × *Scarcity Hours*

This Capacity Performance Payment will reach the monthly stop-loss limit when it equals 1 MW × Forward Capacity Auction Starting Price, or $15,000. Equating the stop-loss limit to the Capacity Performance Payment in the formula above yields the following formula for *Scarcity Hours:*

Required Scarcity Hours = $15,000 / ($5,455 × [0 – 0.75 × 1 MW]) = 3.7 hours

This calculation means that, under these assumptions, a zero-performing resource's Capacity Performance Payment will not reach the monthly stop-loss limit unless there are 3.7 hours of scarcity conditions, or more, in an Obligation Month.

It is possible for the New England system to have 3.7 hours of scarcity conditions or more in a month. However, that is not common. For example, the ISO has analyzed the number of hours of scarcity conditions from 2010 to present (through December 2013), based on the ISO's current energy market scarcity pricing rules. This analysis includes the actual number of hours of scarcity conditions after the current RCPF values took effect in June 2012, and a case-by-case dispatch simulation 'backcast' analysis of the number of hours that would have occurred prior to that date had the current RCPF values been in place from 2010 through 2012. This analysis indicated an average number of hours *annually* of only 7.66. Until July 19, 2013, the most that occurred in any single month is 4 hours. Thus, while it is possible for the New England system to have 3.7 hours of scarcity conditions in a month, that is not common in the data since the FCM's inception.

Moreover, even under conditions where the total system capacity equals the Installed Capacity Requirement, and the system is at planning criteria, the ISO's planning model predicts an expected number of scarcity hours of 21.2 *annually.* (*See* Section V.D, p. 107, earlier in this testimony). The finding that the expected number of scarcity hours annually is 21.2 at criteria suggests that a realization of 3.7 or more scarcity hours may occur in a hot summer month, but it is not likely to recur regularly over the course of the year.

Note that, in this example, differences in the numerical values of the assumptions could yield a higher or lower number of scarcity hours. Of primary interest is the

fact that during the phase-in period, when the Capacity Performance Payment Rate is lower, a higher number of scarcity hours must occur before a poorly-performing resource would reach the stop-loss limit. This implies that loss-limiting events would be even less frequent during the phase-in periods.

To see this, note that the Full PPR of $5,455 is 2.73 times larger than the initial Capacity Performance Payment Rate of $2,000, which I calculate as 2.73 = 5,455 / 2,000. Using the same assumptions as in the preceding example, this means a zero performer would not reach the monthly stop-loss limit unless there are 2.73 times as many scarcity hours as the 3.7 shown in the previous example. That amounts to 2.73 × 3.7 hours = 10.1 hours of scarcity conditions in a month. Thus, it is not anticipated that poorly-performing resources would reach the monthly stop-loss limit frequently.

Q: You stated above that this stop-loss limit is consistent with a capacity resource's maximum loss exposure under other, existing Tariff provisions. Please explain further.

A: From an economic perspective, the monthly stop-loss limit is analogous to a capacity resource's maximum loss exposure under the existing significant decrease provisions of the Tariff.[35] Stated in simplified terms, if a capacity resource suffers a significant decrease in expected performance before the third

[35] *See* Tariff Section III.13.4.2.1.3(b).

annual reconfiguration auction (held approximately four months before the capacity commitment period begins), the ISO would submit a bid on behalf of the capacity resource in that reconfiguration auction for its capacity reduction at the Forward Capacity Auction Starting Price.

In this situation, the resource would effectively be required to 'buy out' of its non-performing Capacity Supply Obligation MW at a price up to the Forward Capacity Auction starting price. However, the resource still continues to receive the Capacity Base Payment, based upon its original Capacity Clearing Price. In this situation, the resource's maximum loss exposure is equal to the difference between the Capacity Clearing Price and the Forward Capacity Auction Starting Price for each affected Capacity Supply Obligation MW. Stated as a formula, it faces a maximum loss exposure of:

Maximum loss exposure = *Clearing Price* × CSO MW – *FCA Starting Price* × CSO MW.

This maximum loss exposure, if applied on a monthly basis, is equivalent to the resource's maximum potential net loss under the monthly stop-loss mechanism. The reason is simple: On the right-hand side of the equality in the formula above, the first product is also equal to the resource's Capacity Base Payment. The second product is equal to its Capacity Performance Payment when it reaches the monthly stop-loss limit. This means that, in a worst-case scenario, a resource's

Monthly Capacity Payment under Pay For Performance equals the same formula as above.

This equivalence is apparent using a few simple formulas. Under Pay For Performance, a resource's Monthly Capacity Payment is the sum of its Capacity Base Payment and its Capacity Performance Payment. In the worst-case scenario for a resource, its Capacity Performance Payment is equal to the (negative of the) monthly stop-loss limit. This means the Monthly Capacity Payment provides a maximum potential net loss given by the following formula:

Monthly Capacity Payment = Capacity Base Payment – Monthly Stop-Loss Limit

Recall now that the Capacity Base Payment is calculated as *Clearing Price* × CSO MW, and the monthly stop loss limit is calculated as *FCA Starting Price* × CSO MW. Inserted into the preceding formula for the Monthly Capacity Payment, we find that under Pay For Performance a resource's maximum monthly loss exposure is:

Maximum loss exposure = Clearing Price × CSO MW–*FCA Starting Price* × CSO MW.

Stated in simple terms, a resource's maximum loss under the existing significant decrease provisions of the Tariff is equivalent, if applied on a monthly basis, to the resource's

maximum loss under the Pay For Performance stop-loss mechanism. This is not a coincidence; the monthly stop-loss mechanism is intended to maintain this equivalence.

In summary, the monthly stop-loss mechanism takes an existing liability limit on a capacity resource's net financial loss prior to the start of the Capacity Commitment Period, and extends that existing liability limit to apply, on a monthly basis, throughout the Capacity Commitment Period under the Pay For Performance design.

It is important that the monthly stop-loss limit harmonize with the existing liability limit built into the existing significant decrease provisions. Both of these provisions provide resources with financial incentives to trade out of their obligations or to enter into the reconfiguration auction if they are unable to perform. And if the monthly stop-loss limit were set below the existing liability limit in the significant decrease provisions, it could undermine those incentives. Imagine, for instance, that a resource discovers after the Forward Capacity Auction that its operating circumstances have changed for the worse, such that it expects to have poor performance throughout the Capacity Commitment Period. If the monthly stop-loss limit was materially lower (in magnitude) than the existing liability limit in the existing significant decrease provisions, the resource may have a perverse financial incentive to not trade out of its Capacity Supply Obligation and instead simply pay the stopped financial losses. This perverse financial incentive would be present if, for example, the bilateral market in which participants trade their obligations during the commitment period is tight and

obligations trade at close to the Forward Capacity Auction Starting Price. To ensure that the monthly stop-loss limit works in harmony with this existing Tariff provision, it is important that the Capacity Performance Payment not be limited to less than the Forward Capacity Auction Starting Price.

Q: Can a resource that has reached the monthly stop-loss limit early during an Obligation Month "come back above" the stop-loss limit by the end of the month?

A: Yes. A resource that reaches the monthly stop-loss limit early in the month can, with strong performance in scarcity conditions that occur subsequently during the same month, finish the month with a net financial position better than the monthly stop-loss limit. This design element is consistent with the third and fourth principles of the stop-loss design. Specifically, it helps to reduce the frequency with which resources may reach the stop-loss limit. In addition, it provides a resource with an incentive to perform in the event that its losses have reached the monthly stop-loss limit. It is also consistent with the first principle, simplicity, because it means that the order of a resource's performance within a month does not affect its Capacity Performance Payment at the end of the month.

Q: Can you provide a simple example of this possibility?

A: Assume the Capacity Clearing Price is $5,000 per MW-month, the Full PPR of $5,455 per MWh, and there is a scarcity event that lasts 4 hours with an average Capacity Balancing Ratio of 0.75. Without a monthly stop-loss, a resource with a

1 MW Capacity Supply Obligation that has zero performance would accrue the following contribution to its monthly Capacity Performance Payment:

$$\$5{,}455 \times [0 - 0.75 \times 1 \text{ MW CSO}] \times 4 \text{ hours} = -\$16{,}365$$

In this example, the resource's Capacity Performance Payment to date exceeds the monthly stop-loss limit of $15,000. If there were no further scarcity conditions in the month, its final monthly Capacity Performance Payment would therefore be –$15,000.

Now suppose there is a second scarcity event that also runs 4 hours, again with an average Capacity Balancing Ratio of 0.75. The resource provides its full 1 MW during the second event. For the second event, it would accrue the following contribution to its monthly Capacity Performance Payment:

$$\$5{,}455 \times [1 - 0.75 \times 1 \text{ MW CSO}] \times 4 \text{ hours} = +\$5{,}455$$

The resource's total Capacity Performance Payment for the month is the sum of the two contributions, or –$16,365 + $5,455 = –$10,910. The resource's strong performance during the second scarcity condition means it does not reach the monthly stop-loss limit, and it increased its Capacity Performance Payment by $4,090, calculated as: $15,000 – $10,910.

Q: Are there any other adjustments to a resource's performance in calculating its monthly stop-loss limit?

A: Yes. There is an adjustment if a capacity resource has actual performance during scarcity conditions that exceeds its Capacity Supply Obligation. The stop-loss limit applies to a resource's performance *up to* its Capacity Supply Obligation. If a resource's performance exceeds its Capacity Supply Obligation, the performance above its obligation is treated separately from the monthly stop-loss calculation. Specifically, performance above a resource's Capacity Supply Obligation MW is credited in a resource's monthly Capacity Performance Payment, but is excluded from the stop-loss calculations.

This treatment of the non-obligated MW of a resource with a Capacity Supply Obligation provides comparability to the non-obligated MW of a resource without a Capacity Supply Obligation. It addition, in some circumstances, it further helps improve a resource's incentives to perform. In the Tariff, this treatment is provided for within the calculation of the monthly stop-loss, if a resource's Capacity Performance Payment is negative.

Q: How is the treatment of performance in excess of a resource's Capacity Supply Obligation equivalent to the treatment of performance by a resource that does not have a Capacity Supply Obligation?

A: Performance during scarcity conditions by a resource without a Capacity Supply Obligation falls outside the stop-loss design, and is simply compensated at the

Capacity Performance Payment Rate according to the Pay For Performance two-settlement design. Performance during scarcity conditions by a resource's non-obligated MW, above its Capacity Supply Obligation, are treated in the same way. Thus, the difference between a resource's performance and its Capacity Supply Obligation, if positive, is treated equivalently under the stop-loss mechanism regardless of the numerical value of its Capacity Supply Obligation, or if it has no Capacity Supply Obligation at all (that is, if its Capacity Supply Obligation is zero).

Q: Is application of the stop-loss mechanism to performance only up to a resource's Capacity Supply Obligation consistent with the objectives of the Pay For Performance design?

A: Yes. This design characteristic strengthens a resource's incentives to perform. Consider a resource that has performed poorly and has already exceeded the monthly stop-loss limit by a quantity such that, even with a strong performance late in the month, it cannot improve its monthly Capacity Performance Payment above (the negative value of) its monthly stop-loss limit. If all performance, including that beyond its Capacity Supply Obligation, is subject to the stop-loss, the resource has (by assumption) no financial incentive to perform. However, if performance above a resource's Capacity Supply Obligation is excluded from the monthly stop-loss limit calculations, the resource can earn additional FCM revenue for superior performance during the remainder of the month. This feature strengthens a resource's incentive to perform, although it is applicable only to

resources with the capability to deliver energy and reserves above their Capacity Supply Obligation.

Q: How do the rules for Capacity Performance Bilaterals under Pay For Performance relate to the monthly stop-loss?

A: As discussed in Section VII.C, the rules for Capacity Performance Bilaterals are simple, as a resource can only trade away positive Capacity Performance Scores. Because of this simple framework, there are no ways for a poorly performing resource to "game" the monthly stop-loss limit by trading behaviors such as acquiring additional negative score through Capacity Performance Bilaterals (and receiving compensation in the trade for doing so) that it would otherwise not pay for if it had reached the monthly stop-loss limit.

C. The Annual Stop-Loss Limit

Q: What is the purpose of the annual stop-loss limit?

A: The purpose of the annual stop-loss limit is to reduce a capacity resource's annual maximum potential net financial loss that could otherwise occur in exceptional circumstances, such as a Capacity Commitment Period with a large number of

annual scarcity hours, spread over many months, in which the capacity resource experiences ongoing poor performance.[36]

Q: At a high level, please explain the annual stop-loss limit.

A: Recall that under the monthly stop-loss limit, a capacity resource's maximum monthly potential net loss is the difference between its Capacity Base Payment and the monthly stop-loss limit. Expressed as a formula:

Maximum monthly potential net loss = Capacity Base Payment – Monthly Stop-Loss Limit

Under the annual stop-loss mechanism, a capacity resource cannot be worse-off, on an annual basis, than three times its maximum monthly potential net loss.

As a simple example, imagine a capacity resource has a monthly Capacity Base Payment of $50,000 and a monthly stop-loss limit of $150,000. Its maximum monthly potential net loss is the difference, which is $50,000 – $150,000 = – $100,000.

[36] *See* revised Tariff Section III.13.7.3.2.

The resource's annual stop-loss limit prevents the resource's net financial loss, over the course of the Capacity Commitment Period, from exceeding three times this maximum monthly potential net loss, or 3 × (–$100,000) = –$300,000.

At a high level, this is a very simple annual stop-loss design. It means that, on an annual basis, a capacity resource's maximum potential net loss is not as large as would be the case in the absence of the annual stop loss limit. Specifically, the annual stop-loss limit reduces a capacity supplier's maximum annual potential net loss by 75 percent, relative to the twelve monthly stop-loss limits alone.

Q: How is the annual stop-loss limit applied to determine a resource's monthly capacity payments?

A: The value of the annual stop loss limit is applied to a resource's cumulative Capacity Performance Payments over the course of the Capacity Commitment Period.

Let's continue the previous simple example. First, recall that a resource's total capacity revenue for the Capacity Commitment Period is the sum of its twelve monthly Capacity Base Payments and its twelve monthly Capacity Performance Payments. To simplify the explanations, I will refer to each of these twelve monthly sums as an annual amount; that is, I'll refer to the sum of the resource's twelve monthly Capacity Base Payments as its annual Capacity Base Payment, and so forth. Expressed as a formula:

annual capacity payment = annual Capacity Base Payment

+ annual Capacity Performance Payment

As explained in the previous example, the annual stop-loss mechanism is designed so that the resource's annual capacity payment is limited to a maximum annual potential net loss of –$300,000. Next, note that this occurs if, and only if, the resource's negative Capacity Performance Payments reach the annual stop-loss limit. Inserting these terms in the previous formula, we obtain:

Maximum annual potential net loss = annual Capacity Base Payment

– annual stop-loss limit

Last, we can now evaluate the terms in this formula to determine the annual stop-loss limit. Continuing with the example, as I assumed in the previous answer, the resource has a monthly Capacity Base Payment of $50,000. Its annual Capacity Base Payment is therefore 12 × $50,000 = $600,000. If we insert the value for its annual Capacity Base Payment of $600,000, and the previously-obtained value for this resource's maximum annual potential net loss of –$300,000, into the preceding formula, we find:

–$300,000 = $600,000 – *annual stop-loss limit*

It is convenient to re-arrange the terms in this formula to obtain:

$$\textit{annual stop-loss limit} = \$300{,}000 + \$600{,}000 = \$900{,}000$$

This means the means the resource's annual stop-loss limit is $900,000. Over the commitment period, the resource's net Capacity Performance Payments will be limited, in its worst-case scenario, to –$900,000.

Q: Is the annual stop-loss limit applied to limit negative Capacity Performance Payments on an ongoing basis during the commitment period, or is it only applied at the end of the Capacity Commitment Period?

A: Importantly, the annual stop-loss limit is applied to a resource's cumulative Capacity Performance Payments on a rolling basis during the Capacity Commitment Period. That is, each Obligation Month, the ISO will check whether the resource's cumulative year-to-date Capacity Performance Payments (after application of the monthly stop-loss limit each month) exceed the annual stop-loss limit. If this occurs, the Capacity Performance Payment for the current Obligation Month will be limited so that the resource's cumulative negative Capacity Performance Payments do not exceed the annual stop-loss limit. The resource will continue to receive its monthly Capacity Base Payment even if its Capacity Performance Payment is limited by the annual stop-loss limit prior to the end of the commitment period.

Q: Please explain how the annual stop-loss limit is determined in further detail. How will the ISO calculate the annual stop-loss limit on a rolling basis each Obligation Month?

A: There is a general formula for determining the annual stop-loss limit. This general formula is used in the Tariff. It is:

$$[\,3 \times (\textit{Clearing Price} - \textit{Starting Price}) - 12 \times \textit{Clearing Price}\,] \times \max \text{CSO MW}$$

The first set of terms in the square brackets, $3 \times (\textit{Clearing Price} - \textit{Starting Price})$, corresponds to three times the resource's maximum monthly potential net loss, on a per Capacity Supply Obligation MW basis.

The second set of terms in the square brackets, or $12 \times \textit{Clearing Price}$, corresponds to the resource's annual Capacity Base Payment per Capacity Supply Obligation MW.

The final term in this expression, max CSO MW, is the largest value of resource's Capacity Supply Obligation MW during the capacity commitment period to date. This adjustment is necessary for resources that have different values of their Capacity Supply Obligation MW in different months of the year. I explain this adjustment in more detail further below.

Q: Is the annual stop-loss mechanism consistent with the four design principles you identified above?

A: Yes, the annual stop-loss mechanism satisfies the four stop-loss design principles listed previously. These properties are (1) simplicity, (2) transparency, (3) the economic incentives of the Pay for Performance design are maintained, and (4) loss-limit events should occur infrequently.

Q: Please explain why the annual stop-loss limit satisfies the first principle – simplicity.

A: The annual stop-loss mechanism's relationship to the monthly stop-loss limit is simple and intuitive: It limits a resource's maximum annual potential net loss to three times its maximum monthly potential net loss. The annual stop-loss limit value can be easily calculated by market participants using the formula above, and incorporated into their valuation of a Capacity Supply Obligation prior to the Forward Capacity Auction or in their determination of whether to trade a Capacity Supply Obligation during the commitment period.

Q: Please explain why the monthly stop-loss limit satisfies the second principle – transparency.

A: Under this annual stop-loss design, a resource can determine its maximum annual net loss exposure *prior to* participation in the Forward Capacity Auction, as a function of its Forward Capacity Auction offer price. For example, suppose a capacity supplier intends to offer a 10 MW resource into the Forward Capacity

Auction at an offer price of $5 per kw-month. Using the formula and example above, if the resource clears in the Forward Capacity Auction, its maximum annual net loss exposure is at most –$300,000 per MW-year. If the Forward Capacity Auction clears at a higher price than $5, the resource's bid would be accepted and its maximum annual loss exposure would be closer to zero, *i.e.*, its worst case annual losses decrease if the Forward Capacity Auction clearing price exceeds its offer of $5. Alternatively, if the Forward Capacity Auction clears at a lower price than $5 per kw-month, the resource's offer does not clear and its maximum annual net loss exposure is zero in the FCM settlement.

This transparency property enables a resource owner to assess, based on a planned capacity price offer, the maximum annual potential loss it may face under Pay For Performance for its Capacity Supply Obligation MW. This enables it to communicate its maximum potential annual loss, as a function of its capacity price offer and Capacity Supply Obligation MW, to entities such as credit committees, risk management teams, or other parties providing financing to a capacity supplier. It also means a capacity supplier can account for, and thereby limit, its maximum potential annual net loss based on its capacity offer price.

Q: Please explain why the monthly stop-loss limit satisfies the third principle – the economic incentives of Pay For Performance are maintained.

A: The annual stop-loss mechanism is based on a multiplier of three: A resource's maximum annual potential net loss is three times larger than its maximum

monthly net loss. This element of the annual stop-loss design has an important property. Mathematically, this ensures that a capacity supplier cannot reach its maximum potential net loss, on an annual basis, prior to completion of the first three summer months of the capacity commitment period – regardless of the Forward Capacity Auction clearing price.

The ISO's planning models suggest that, in most years, a majority share of all scarcity conditions are expected to occur during these three months. It is particularly important that the annual stop-loss mechanism not attenuate performance incentives prior to the completion of these first three summer months of the capacity commitment period, and this design ensures that.

For these reasons, it is reasonable to anticipate that resources will reach the annual stop-loss limit infrequently. This indicates that, with infrequent exception, a resource's incentive to perform is not affected by the annual stop-loss limit.

Q: Please explain why the monthly stop-loss limit satisfies the fourth principle – that loss-limiting events should occur infrequently.

A: In order for a resource to reach the annual stop-loss limit, its Capacity Performance Payments must reach the monthly stop-loss limit in at least three months (or reach the equivalent sum over a longer time period). As noted previously, the monthly stop-loss limit is set sufficiently high that events in which it is reached should occur infrequently. Therefore, events in which it is reached

three times will occur even less frequently. Moreover, after a resource has performed sufficiently poorly to reach the monthly stop-loss limit twice, it may have strong incentives to shed its obligation to another resource that can perform; by doing so, the poorly performing resource would not incur sufficient losses in the FCM settlement to reach the annual stop-loss limit. In sum, it is reasonable to anticipate that a resource reaching the annual stop-loss limit will be an infrequent event.

Q: Does the resource's maximum potential net loss depend on *when* it hits the annual stop-loss limit – that is, at what point during the commitment period?

A: No. Because a resource receives its Capacity Base Payment in each month even after its negative Capacity Performance Payments have reached the annual stop-loss limit, it will receive the same total capacity payment for the commitment period regardless of when (that is, in which month) it reaches the annual stop-loss limit.

Q: Can a resource that reaches the annual stop-loss limit early in the year "come back" above the annual stop-loss with strong performance later in the year?

A: Yes. A resource that reaches its annual stop-loss limit before the end of the commitment period can complete the year better off than at the annual stop-loss limit, if it performs well later in the year. This design ensures that when a

resource reaches the annual stop-loss limit, it still has an incentive to perform because it may earn additional revenue for its additional performance.

The mechanics surrounding how a resource "comes back" above the annual stop-loss are similar to those for the monthly stop-loss, as explained earlier. If a resource that has reached the annual stop-loss limit provides more energy and reserves during subsequent scarcity conditions than its share of the system obligation, it receives positive monthly Capacity Performance Payments. If these positive monthly Capacity Performance Payments raise the resource's cumulative (negative) Capacity Performance Payments above the annual stop-loss limit, it will receive additional net revenue for its additional performance.

Q: You stated earlier that in determining a resource's annual stop-loss limit, the calculation will be based on the maximum of its Capacity Supply Obligation MW during the Capacity Commitment Period to date. Please explain further.

A: The Pay For Performance design permits trading of Capacity Supply Obligations between months. This flexibility allows resources to adjust to changing expectations surrounding their future performance and system conditions. However, the annual stop-loss limit is calculated on a per Capacity Supply Obligation MW basis, which requires a single annual Capacity Supply Obligation value. We use the maximum year-to-date Capacity Supply Obligation MW for two reasons: it is simple, and it preserves a resource's economic incentives to

perform – and to only acquire additional Capacity Supply Obligation MW if it expects to perform.

Specifically, if a resource acquires additional Capacity Supply Obligation MW through a bilateral trade or reconfiguration auction at any time during the commitment period, it increases its annual stop-loss limit. This provides a strong disincentive for a resource to acquire additional Capacity Supply Obligation MW if it expects it may perform sufficiently poorly to reach the annual stop-loss limit.

Q: Are there any other adjustments to a resource's performance in calculating its annual stop-loss limit?

A: Yes. As with the monthly stop-loss calculation, and for the same reasons, the annual stop-loss limit applies to a resource's monthly performance *up to* its Capacity Supply Obligation. If a resource's performance exceeds its Capacity Supply Obligation, the performance above its obligation is treated separately from the annual stop-loss calculation. Specifically, performance above a resource's Capacity Supply Obligation MW is credited in a resource's monthly Capacity Performance Payment, but is excluded from the stop-loss calculations.

D. Treatment of Resources with Multi-Year Commitments

Q: How are resources treated that recently cleared as new, and that elected multiple-year commitments?

A: The New England system has some capacity resources that cleared as new resources before the implementation of Pay For Performance, and elected to have the relevant Capacity Clearing Price apply for multiple Capacity Commitment Periods that include (one or more) years after Pay For Performance is implemented.

For these resources, there is a slightly different stop-loss treatment. Specifically, these resources will have a monthly stop-loss limit based on their applicable Forward Capacity Auction price, rather than the auction starting price, for the duration of their multiple-year commitment. This means their maximum potential net loss, each month and annually, is limited to zero and is therefore analogous to their current FCM loss limit.[37]

The reason for this differing treatment is that resources that cleared as new prior to the ninth Forward Capacity Auction and elected multiple-year treatment had no knowledge of the rewards and risks to which they would be subject under Pay For Performance, which will apply to at least some portion of their multiple-year commitment. Such resources did not have the opportunity to price those factors into their original Forward Capacity Auction offers (when they cleared as new resources). Their stop-loss treatment will limit the risk under Pay For

[37] *See* revised Tariff Section III.13.7.3.1.

Performance for such resources in a manner consistent with their original offers in the Forward Capacity Auction.

Q: Can such a resource elect different treatment?

A: Some of these resources may prefer the greater rewards, and be willing to accept the greater performance risks, afforded by full participation in Pay For Performance. For this reason, the Pay For Performance rules allow resources that cleared as new prior to the ninth Forward Capacity Auction and that elected multiple-year treatment to opt out of the remaining years of its multiple-year election.[38] This option can be exercised at any point in the resource's remaining multiple-year commitment, but is irrevocable. A resource choosing to so opt out will participate in subsequent Forward Capacity Auctions in the same manner as other Existing Capacity Resources.

E. Treatment Of The Net Surplus Each Obligation Month

Q: You indicated earlier that, because of the stop-loss mechanism, the net surplus after all Capacity Performance Payments are settled each month may be positive or negative. Please explain further how the net surplus is allocated in each case.

[38] *See* revised Tariff Section III.13.7.3.3.

A: Consistent with the mutual insurance conceptual framework discussed earlier in this section of the testimony, the net surplus will be allocated, in its entirety, among capacity suppliers each month.[39] Specifically:

If the net surplus is positive, the net surplus is allocated to all capacity suppliers on a pro-rata (per Capacity Supply Obligation MW) basis, excepting resources with Capacity Performance Payments that are limited by either the monthly or the annual stop-loss limits that month. If a resource has reached (either) stop-loss limit, its pro-rata share of the net surplus is reduced (down to a minimum of zero), dollar for dollar, by its 'insured losses.' In effect, this treatment requires a stopped-out resource to reimburse, from its pro-rata share of the net surplus, the insurance pool of all other capacity suppliers for covering its stopped-out losses *before* the stopped-out resource receives any allocation of the net surplus.

If the net surplus is negative, the net surplus is similarly allocated to all capacity supply resources on a pro-rata (per Capacity Supply Obligation MW) basis, excluding resources with Capacity Performance Payments that are limited by either the monthly or the annual stop-loss limits that month. The reason for the exclusion is that to do otherwise would exceed these resources' stop-loss limits, which is contrary to the stop-loss mechanism design objective.

[39] *See* revised Tariff Section III.13.7.4.

In the special case that a resource does not reach a stop-loss limit during the month, but a pro-rata allocation of a negative net surplus would yield financial losses in excess of its maximum potential net loss for the month, the stop-loss limit will be honored and the balance of the net surplus allocated to the remaining capacity suppliers.

These calculations are performed separately for each type of Capacity Scarcity Condition and for each Capacity Zone. (In the Tariff, each of the three types of reserve deficiencies that I described in Section VII.A is called a type of Capacity Scarcity Condition). Here's what that means. If, for example, Capacity Scarcity Conditions occur in only one zone during a particular Obligation Month, then the net surplus is allocated, following the pro-rata rules, among the capacity resource in that zone. Alternatively, if all Capacity Scarcity Conditions apply to all Capacity Zones during a particular Obligation Month, then the net surplus is allocated, following the pro-rata rules, among all capacity resources in the system. And, last, if there are some Capacity Scarcity Conditions that apply to all Capacity Zones, and other Capacity Scarcity Conditions that apply to only one Capacity Zone, both during the same Obligation Month, then the net surplus is first divided in proportion to the duration of each type of Capacity Scarcity Condition, and then each portion is allocated as in the two previous cases. This process ensures that the resources whose performance contributes to the net surplus due to a Capacity Scarcity Condition in their Capacity Zone are also the

resources that primarily bear the benefit (if the net surplus is positive) or cost (if it is negative) of the insurance that the stop-loss mechanism provides.

Q: When the net surplus is allocated among the capacity suppliers in (one or more) Capacity Zones, why is the allocation on a pro-rata per Capacity Supply Obligation MW basis?

A: Note that whether the net surplus is positive or negative, *pro-rata* means in equal dollar amounts per Capacity Supply Obligation MW. Other things equal, if one capacity resource has twice the Capacity Supply Obligation MW of another, the larger of the two resources would receive twice the net surplus allocation of the smaller resource (in dollar terms), but they would each receive the same allocation in dollars per Capacity Supply Obligation MW terms.

This pro-rata rule means the allocation of the net surplus is not a function of individual resources' performance during the month, only their Capacity Supply Obligation MW each month. That is by design, and minimizes distortions to a resource's marginal performance incentives during scarcity conditions. That is consistent with the stop-loss design principle to minimize incentive distortions.

Taken together, these allocation rules are consistent with the mutual insurance concept for the stop-loss design. When the net surplus is positive, the allocation rule means that all capacity resources that do not incur insured losses receive (a portion of) the surplus, which may offset (to some degree) the negative net

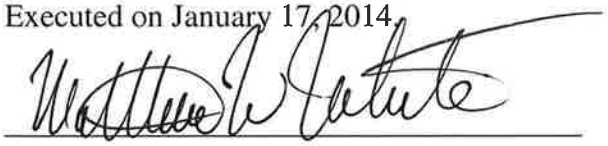
surplus allocation they periodically experience. When the net surplus is negative, the allocation rule means that each capacity supplier bears (a portion of) the financial consequences when a capacity resource performs poorly enough to exceed the stop-loss limit. That is the central purpose of a risk-sharing mutual insurance pool. Regardless of whether there is a positive or negative net surplus in a particular month, however, all capacity suppliers' total FCM compensation is reduced (from what it otherwise would be) whenever a capacity resource performs poorly enough to reach the annual or monthly stop-loss limit.

Q: Does that conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.



Matthew White

Chief Economist

Attachment I-1d

Testimony of Peter Cramton on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF PETER CRAMTON
ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Please state your name, title, and business address.

A: My name is Peter Cramton. I am a Professor of Economics at the University of Maryland. My business address is Economics Department, University of Maryland, College Park, MD 20742.

Q: Please describe your work experience and educational background.

A: I am a Professor of Economics at the University of Maryland. Since 1983, I have conducted research on auction theory and practice. This research appears in the leading economics journals. The main focus is the design of auctions for many related items. Applications include spectrum auctions, electricity auctions, and treasury auctions. On the practical side, I am Chairman of Market Design Inc., an economics consultancy founded in 1995, focusing on the design of auction markets. I have advised numerous governments on market design and I have advised dozens of bidders in high-stake auction markets. Since 1997, I have

advised ISO New England Inc. ("ISO") on electricity market design and was a lead designer of New England's Forward Capacity Market ("FCM"). I led the design of electricity and gas markets in Colombia, including the Firm Energy Market, the Forward Energy Market, and the Long-term Gas Market. Since 2001, I played a lead role in the design and implementation of electricity auctions in France and Belgium, gas auctions in Germany, and the world's first auction for greenhouse gas emissions held in the UK in 2002. I led the development of innovative auctions in new applications, such as auctions for airport slots, wind rights, diamonds, medical equipment, and Internet top-level domains. I received my B.S. in Engineering from Cornell University and my Ph.D. in Business from Stanford University.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to comment on the ISO's proposed Pay For Performance ("PFP") reforms to its FCM.

Q: Can you summarize your main points?

A: Yes. I wish to emphasize four main points about the PFP design. First, PFP is an economically sensible design based on sound market principles, appropriately applied to capacity markets. Second, PFP fixes important shortcomings of the current FCM. Third, a high performance payment rate is appropriate and is

economically well-justified. Fourth, PFP induces a FCM with desirable long-run properties. My testimony will explain each of these points in detail.

III. PFP IS AN ECONOMICALLY SENSIBLE DESIGN BASED ON SOUND PRINCIPLES FOR CAPACITY MARKETS

Q: What are the key principles of the PFP design?

A: The most basic principle of the PFP design is in its name: *pay for performance*. Resources earn the capacity payment based on performance during scarcity conditions. This is accomplished through the definition of the capacity product, which includes an obligation to supply during hours of reserve shortage. Resources are paid based on the service provided. If a resource meets its performance obligation, it receives its full capacity payment; if the resource underperforms, it receives a smaller payment; and if the resource over-performs, it receives a larger payment.

The supply obligation is load-following, so that consumers are fully-hedged, but not over-hedged. In any scarcity hour the total supply obligation equals total demand—load plus reserve requirements.

Q: Why is it economically sensible to put stronger performance incentives in the capacity market?

A: The motivation for the capacity market is to address a demand-side flaw, the absence of demand response. This causes the energy price to be set too low during periods of scarcity, creating missing money. One could restore the missing money with an "energy only" design by setting a high scarcity price during hours of reserve shortage. The scarcity price would be set in the ISO Tariff to induce the desired level of reliability. The PFP design in the FCM works in the same way as the "energy only" design, but with a forward contracting model that addresses several problems of the "energy only" design. Specifically, the forward contracting coordinates investment at the desired reliability level, reduces payment risk for both consumers and generators, and mitigates market power in the energy market during periods of scarcity.

PFP provides the same strong performance incentives as in the "energy only" market with an appropriately set scarcity price. This is accomplished by paying resources based on performance during reserve shortages.

Q: Are there other key principles of the PFP design?

A: Yes. A second principle is *resource neutrality*. A resource should receive the same compensation for the same performance, regardless of technology. This "equal pay for equal work" is grossly violated in the current design. Unreliable resources that fail to provide energy or reserves in shortage situations often receive the same compensation as reliable resources that do provide services during shortages.

A third principle is to *reward outputs, not inputs*. In most markets, consumers pay for the goods and services delivered. Payments are based on outputs of production, not inputs. The PFP design works in the same way. Consumers pay for what they value. PFP also simplifies the market, since there is just a single product and a single price, or one per zone in the event zonal constraints bind. All suppliers and technologies compete on the same basis. Suppliers that can more efficiently convert inputs to outputs are rewarded.

Q: Doesn't the PFP design cause suppliers to bear performance risk?

A: Yes. With PFP, suppliers do bear performance risk. This is both intended and appropriate. Performance risk must be borne by consumers or suppliers. Putting performance risk on suppliers is desirable, since suppliers make a variety of decisions that impact performance. It is this performance risk that motivates good supplier decisions. A supplier will not invest in performance improvements if the supplier does not bear the risk and receive the rewards for its performance. The performance incentives cause the supplier to see and feel the economic consequence of decisions that impact performance. Furthermore, having consumers bear the performance risk is wholly inappropriate; they can neither control that risk nor change suppliers' behavior to manage the risk. Likewise, it is equally inappropriate to socialize the risk among all resources. Incentives and consequences need to be placed directly upon the resources that can control them.

Q: But some events that impact performance are not within the supplier's control. Is it still desirable to base payments on outputs?

A: Yes. There are two main reasons why this is desirable. First, risks not subject to a supplier's control must be borne either by consumers or the supplier. Consumers have no control of these risks either, so there can be no incentive benefit in placing this risk on consumers.

Second, placing the risk on the supplier affects what clears in the capacity market in ways that are desirable from both an economic and a reliability standpoint. Specifically, a supplier that is less likely to perform, even if due to reasons beyond the supplier's control, will place a higher offer into the FCA to account for this risk. As a result, the less reliable supplier will be less likely to clear. This mechanism—placing risk on suppliers, rather than on consumers, for factors outside of either party's control—enables the capacity price mechanism to work in an economic manner to clear the resources that are most likely to deliver when they are needed.

This approach also simplifies the market, because it is unnecessary to assign blame for failures to perform. The market simply measures output during scarcity.

Q: Can you describe the mechanics of the PFP design at a high level?

A: PFP is a two-settlement design—a forward sale that is then settled based on deviations at delivery. There is nothing novel or complicated about this design. It

is equivalent to the structure of the energy market and many other forward contracts. Each supplier takes on a forward obligation and then covers that obligation with its own supply or purchases supply from others. The principal difference between PFP and a forward energy contract is that with PFP it is necessary to set the settlement price (the performance payment rate) in the ISO Tariff, since in a shortage situation there are no competitive offers with which to determine a market price.

The PFP design shares the same key benefit of other two-settlement systems: efficient performance. The capacity supplier faces strong marginal incentives to perform during shortages and any deviations from forward obligations are automatically settled at delivery. Poor performance is not "penalized." Rather, deviations both positive and negative are settled at the performance payment rate. A negative deviation is simply a purchase of supply through the pool from another resource at the time of delivery.

Q: Are there exemptions in the two-settlement design for non-performance?

A: There are no exemptions. This is a critical feature in simplifying and improving the market. A policy of no exemptions provides strong and uniform performance incentives. It is a hallmark of two-settlement designs. Deviations from forward obligations are settled at delivery. No exemptions.

This is just like in the day-ahead energy market. When a supplier fails to deliver on its day-ahead sale, the deviation is made up with a real-time purchase. There is no debate about why the supplier was short and whether the deviation was justified. This lack of exemptions is what makes the two-settlement design so effective. Obligations and remedies are clear.

As another example, consider the forward grain market. Suppose the farmer sells a quantity of grain forward at a fixed price. He bears all the risk of factors—either positive or negative—that impact his performance. If there is a drought and his harvest is poor, he covers any shortfall with a spot purchase at the higher market price caused by the drought. If the farmer's yield is especially high, any surplus beyond the forward obligation is sold at the spot price. If the farmer's grain is destroyed in transit, the forward obligation is met with a spot purchase. All deviations, whatever the cause, are settled at the spot price.

A supplier of course likes exemptions consistent with the chief weaknesses of its fleet. Slow-start resources want to be exempt unless given sufficient advance notice of a shortage; resources with long maintenance outages want an exemption for planned maintenance; resources in locations vulnerable to transmission problems want transmission exemptions; resources with fuel delivery challenges want a no-fuel exemption. The list is endless.

However, in each of these cases, despite the chorus of "it's not my fault," some of the resource's reliability weakness is the supplier's fault. The supplier can invest in more responsive resources; the supplier can shift its obligation to another during scheduled maintenance; the supply can locate where transmission is more robust; and the supplier can invest in dual-fuel capability to protect against gas delivery problems.

Introducing exemptions distorts incentives, favoring some suppliers at the expense of others. For example, a transmission exemption encourages resources to locate in areas with transmission problems. These resources are paid for more reliability than they deliver.

A policy of no exemptions creates a level playing field. Responsibilities are clear and settlement is straightforward. Suppliers do bear greater performance risk, but it is precisely this risk that motivates performance-improving investments.

Q: But in many cases the relevant decisions that impact performance were made long ago. Why should these resources face high marginal incentives to perform?

A: It is important to remember that the FCM is a long-run market. The market must provide incentives that work well in the long run, both before and after investments are made. Indeed, a primary goal of the capacity market is to motivate efficient investment in the right resources. High marginal incentives

reward long-run investments that improve performance and reliability. Without these strong incentives, costly investments to improve performance would not be made. Moreover, these strong incentives must be maintained throughout the life of the project for this is the assumption on which the investment is initially made.

Even after long-run investments have been made, strong performance incentives are needed to foster medium and short-term investments in reliability. Investors, seeing the price incentive, can respond creatively to offer consumers reliable supply at least cost. For example, by lining up replacement supply during a long outage or investing in more reliable fuel delivery. Suppliers are not told what to do; they are simply rewarded based on the output delivered. This is the chief advantage of using prices to motivate behavior and is the hallmark of a market-based system.

Q: But don't these strong performance incentives make supplier revenues highly volatile?

A: No. An important feature of the PFP design is to reduce the volatility of supplier revenues and consumer expenditures from year to year relative to an "energy only" market design. The risk reduction stems from the way the capacity payment substitutes for the energy rents that otherwise would be earned during scarcity hours. Specifically, the capacity payment reflects the *expected* energy rents during scarcity (a constant), rather than the *actual* energy rents during scarcity, which vary greatly from year to year as a result of many random events. A supplier that

meets its share of the system performance obligation on average over the year has a net performance payment of zero, and receives its full capacity payment. Suppliers on average do meet their obligations, aside from the small quantity of MWh unserved during reserve shortages. The supplier's capacity and fuel contracts serve to hedge the risk stemming from the capacity supply obligation. Consumers meanwhile pay a fixed amount for energy during scarcity hours. Risk is reduced on both sides of the market.

Variation in supplier payment is limited to deviations in performance. The only way to further reduce supplier risk would be to weaken performance incentives. But this would compromise the good investment incentives that PFP creates. Instead, in the PFP design, suppliers reduce risk through investments that improve the reliability of their resources. Thus, PFP reduces supplier risk to the extent possible without damaging the incentives to invest in reliability.

Q: Won't this make capacity expensive for consumers?

A: No. In fact, over the long-run the PFP design will reduce the total cost of reliable energy supply. This is because the PFP design identifies the most cost-effective resources to meet the Installed Capacity Requirement, as I explain below.

Q: Can a supplier also mitigate risk through its bidding in the Forward Capacity Auction ("FCA")?

A: Yes. To minimize risk, a supplier adjusts its bids in the FCA based on the cost of providing reliable performance. For example, consider a 100 MW resource that expects to have a net performance payment of zero with a 60 MW capacity obligation, in other words no performance deviations at the 60 MW level. It would be risky for the resource to take on a capacity obligation greater than 60 MW. Thus, the resource can offer its first 60 MW of capacity into the FCA at a low price and then offer the remaining 40 MW at a higher price, reflecting the greater risk of these additional MWs. Such a bidding strategy is economically sensible. Taking on a capacity obligation consistent with the unit's expected performance reduces risk—the resource provides an excellent hedge for the obligation. But selling additional capacity beyond a unit's expected performance increases risk and needs to be priced higher to account for the additional risk. The supplier's increasing offer schedule reflects the increasing risk of higher levels of capacity obligation. A simple example of this would be the highest block for a combined cycle gas plant. To get the highest megawatts out of the unit will be both much more costly and subject to higher risk. Thus, this last block will be offered at a higher price and will only clear if no other, less expensive resource can take on the obligation.

Q: Doesn't PFP sometimes penalize suppliers for following ISO dispatch instructions?

A: No. Resources are not penalized for following instructions; rather, payments are reduced for failing to meet an obligation to deliver energy or reserves during a

shortage. In fact, the ISO would like the resource to run to help meet energy and reserve needs, but the ISO dispatch instructions reflect a variety of constraints that prevent the unit from running. This could be because of unit limits (start time, ramping rate, etc.) or transmission system limits (inadequate capability). In any event the dispatch instructions reflect what the unit is able to do, not just what the ISO would like the unit to do. This is just another version of the argument that resources should receive exemptions from circumstances allegedly outside of their control, in this case the operational constraints included in the ISO's commitment and dispatch software, and that is false.

As an example, a high-cost resource with a long lead time may not be committed and therefore the resource is not able to supply energy or reserves during a shortage. Its failure to perform means that the resource did not contribute to reliability. The resource therefore should be paid less, even though it followed dispatch instructions. It was not asked to run, because it could not get online in time to reduce the shortage.

The folly of paying non-performing resources is easy to see with an extreme example. Consider a resource with a lead time and marginal cost that are so high that the resource is never committed. Were resources paid for following dispatch instructions then this resource would receive full payment: it never is asked to run and never does so. But this resource clearly makes zero contribution to reliability. It should be paid zero. Following dispatch instructions is not a measure of a

resource's contribution to reliability. Supplying energy or reserves during scarcity hours is.

IV. PFP FIXES IMPORTANT SHORTCOMINGS OF THE CURRENT FCM

Q: Please describe some of the problems of the current FCM and explain how the PFP design addresses these problems.

A: There are several problems with the current FCM. The problems stem from performance incentives being too weak. I will consider each of the problems in turn.

One of the biggest problems is the use of "availability" to measure performance. Currently, there is little consequence for non-delivery during reserve shortages. The reason is the large number of exemptions that crept into the FCM settlement. Resources are credited for being "available" even when they provide no energy or reserves during scarcity conditions.

Availability-based obligations have proven to be a poor design. The availability approach results in the same compensation for different levels of service. High cost, long lead-time resources receive the same payment as low cost, quick start units, even if the latter contribute much more to reliability by providing energy and reserves during scarcity hours. This undermines incentives to invest in short

lead times and other resource attributes that improve performance during shortages.

A further problem with availability-based obligations is that a resource can claim to be available even when it is unlikely it will perform if called. The availability claim is successful when the resource is not called to provide energy. Thus, it is high-cost slow-start resources that are less apt to have their availability tested. The availability metric perversely rewards resources for being less desirable (*e.g.* expensive or slow to start) since they are less apt to have their performance tested.

As an example, consider a resource that does not have dual fuel capability and has not made advance arrangements for fuel and, as a result, faces considerable uncertainty as to whether it could acquire fuel during the operating day. The availability approach gives this resource the incentive to report it is available up until the point when the resource is needed and is called to deliver energy at which point the resource is unable to start for lack of fuel. From a reliability perspective, this is the worst possible outcome. The system operator is relying on the resource to be available if needed, and then the ISO discovers this is not the case. But now it is too late to avoid a scarcity condition.

Q: Are there other problems with the current FCM?

A: Yes. Another problem in the current market is the inadequate incentive suppliers have to invest in reliability-enhancing capabilities that are useful only a few hours

per year. Dual fuel supply is a lead example. New England's heavy reliance on gas and its position at the end of the gas network makes New England especially vulnerable to inadequate gas supply. Backup fuel supply could resolve this systemic reliability risk. However, the current FCM provides little incentives for such investment.

The PFP design greatly improves incentives for investment in resource capabilities that are needed only a few hours per year when the system's reliability is at a heightened risk. By rewarding performance during scarcity hours, PFP targets exactly those investments that improve performance during scarcity events.

Q: In the current market does a non-performing resource receive capacity revenues?

A: Yes. This is the "money for nothing" problem. The current FCM pays capacity resources that do not perform. As a result, it is profitable for a resource that only operates for its annual capability audit to take on a Capacity Supply Obligation ("CSO"). The resource may contribute little, or even zero, to reliability and yet enjoys capacity revenues.

Q: What is the implication of overpayment for poor performers in the current market?

A: As a result of overpaying poor performers, the current FCM suffers from adverse selection. Rather than clearing those resources that achieve the reliability objective at least cost, the market favors less reliable resources. Units with low going-forward costs and poor performance clear before more cost-effective resources that have higher going-forward costs and better performance. The reason is that the performance rewards in the current FCM are inadequate. Weak performance incentives bias the market in favor of less reliable resources. Over time, this bias erodes reliability in New England.

An implication of this adverse selection is the "effective capacity" problem. Effective capacity is the quantity of energy and reserves that the resource delivers during scarcity conditions. Effective capacity may be worse than one would expect based on the Equivalent Forced Outage Rate (EFORd) currently used to set the Installed Capacity Requirement in the FCM. The reason is that weak performance incentives adversely select resources that perform poorly during scarcity hours. Available resources are often not accessible in time to deliver during scarcity conditions. EFORd ignores this, since it only downgrades a resource's performance when it fails to operate when called with adequate lead-time. This introduces a systemic bias in the measurement of effective capacity that reduces system reliability.

The PFP design addresses this problem by clearing resources that expect to perform, rather than systematically selecting underperformers.

Q: Do you see any other flaws in the current market?

A: Yes. Another issue with the current market is the "free option" problem. The current FCM has penalty caps that prevent a net loss on FCM obligations. This means poor performers are playing a game of heads-I-win, tails-I-don't lose. As a result, poor performing suppliers are encouraged to participate in the market when they should exit. This is similar to but distinct from the "money for nothing" problem. The free option problem relates to the downside truncation of any losses when faced with uncertain performance.

Under PFP, resources can have a loss in the capacity market if they perform poorly in a year with a large number of scarcity hours. There is still a limit to losses, but not a complete elimination of the possibility of a loss. The stop-loss limit under PFP is specifically designed to rarely bind and therefore to only rarely harm incentives.

Q: As an expert in market design, is there a root cause that underlies the flaws you have identified in the current FCM?

A: Yes. The basic problem with the current capacity market is the absence of a coherent capacity product definition. Good product definition is essential to all markets. The current FCM product lacks clarity as a result of exemptions and a questionable availability metric. The product is needlessly complex. Furthermore, the too-weak performance incentives create the wrong investment incentives. Unreliable resources are encouraged. The product provides poor incentives for

investments that would contribute to system reliability by improving performance during scarcity.

In contrast, the PFP design has a simple and coherent product definition: physical capacity together with a financial obligation to cover a share of demand during hours of reserve shortage. The physical component guarantees that adequate physical resources will be available. The financial component provides the performance incentives. Since the financial component is a standard two-settlement forward contract, it is easy to create and trade a matching financial security that hedges performance risk. Suppliers anticipating underperformance, say as the result of an extended outage, can purchase the hedge from suppliers anticipating over-performance. Thus, the coherent product motivates efficient performance and enables suppliers to better manage performance risk.

V. A HIGH PERFORMANCE PAYMENT RATE IS NEEDED FOR EFFECTIVE PERFORMANCE INCENTIVES

Q: On what basis is the performance payment rate determined?

A: The performance payment rate ("PPR") follows directly from two basic economic principles. The first is that new capacity must be willing to enter the market when new entry is needed to meet the Installed Capacity Requirement. The second is that a resource that provides zero performance should expect to receive zero revenue. Thus, a resource's expected payment increases linearly from zero with

zero performance to 100% of the net cost of new entry (net "CONE") for an efficient new resource that performs as expected.

Ignoring risk for the moment, new capacity that performs as expected is willing to take on the supply obligation if the capacity price, which in equilibrium must be net CONE, is equal to the expected scarcity rents that are earned in the scarcity hours:

Capacity price = Net CONE = PPR × Expected scarcity hours × Expected scarcity performance.

Thus, PPR = Net CONE / (Expected scarcity hours × Expected scarcity performance). The performance payment rate simply amortizes the net cost of new entry over the expected production of energy and reserves in scarcity hours.

The ISO has estimated the three parameters that determine the performance payment rate as follows:

PPR = Net CONE / (Expected scarcity hours × Expected scarcity performance)

PPR = ($106,394 / MW-year) / (21.2 hours/year × 0.92) = $5,455 / MWh.

The PPR reflects the reliability criterion through the expected number of scarcity hours in the year. The ISO's planning model shows that when the system satisfies

the reliability criterion the expected number of scarcity hours is 21.2. A lower level of reliability would lead to more scarcity hours and a reduced PPR.

The PPR also depends on the expected performance rate, which currently is 0.92 for the type of new generation that the ISO has estimated to be the most cost-effective entrant (a combined cycle unit). Improvements in a new entrant's expected performance would result in a lower PPR, and lower FCM clearing prices; however, given that performance cannot exceed 1.0, there is little scope for improvements in expected performance to have much impact on PPR. Thus, it is unlikely the PPR would need to be modified in future years for this reason.

Finally, the PPR directly depends on net CONE. Net CONE can change in two ways. First, there might be a change in costs. Second, rents in the energy and reserve markets may change. Either of these factors may change over the long term, as technology changes and the energy market evolves.

The PPR should be updated every few years so that it stays at the level consistent with the two basic principles of: (1) supporting entry when needed; and (2) zero pay for zero performance.

Q: What are the advantages of setting the PPR at this level?

A: There are several. The first is good incentives. PPR calculated in this way closely aligns the reward for performance during times of system stress with the region's

desired level of reliability. This reward motivates suppliers to make reliability enhancing investments such as dual-fuel capability. Suppliers also properly consider the reliability tradeoffs when investing in new resources.

A second advantage is that it is cost-effective. The FCA clears the lowest-cost set of resources necessary to satisfy the reliability standard. Resources that are not cost-effective exit the auction because the capacity payment provides insufficient revenues to cover costs. I explain this further below.

A third advantage is transparency. Fixing the PPR in the Tariff helps guide long-term investment decisions and facilitates contracting to hedge performance risk, for example during extended outages.

VI. THE PFP DESIGN HAS DESIRABLE LONG-RUN PROPERTIES

Q: What are the long-run properties of the PFP design?

A: Perhaps the most important property of the PFP design is that it clears the most cost-effective set of resources to meet the ISO's reliability planning requirements. Cost-effectiveness is measured as cost / performance. Resources clear in the FCA based on the capacity cost per MWh delivered in scarcity conditions. The most cost-effective resources clear first.

The reason that under PFP the market clears the most cost-effective resources is simple. Since resources are paid based on performance, better performers earn higher net FCM revenue and poorer performers earn less. All resources that clear have positive expected net FCM revenue, because they are sufficiently cost effective. Resources that do not clear in the FCM are not profitable either because they have high costs, poor expected performance, or both.

In contrast, the current market clears on capacity cost alone, regardless of what performance consumers get for the money. This adversely selects less reliable resources. Consumers are somewhat compensated with a lower capacity price, but overall consumers today end up paying more relative to what they get for their money. This is because many poor performing resources are selected even though they are not as cost effective as some high performing resources that do not clear. Without strong performance incentives, high performing resources are inadequately rewarded for their performance and choose not to participate.

Consumers "get what they pay for" with PFP, since resources are compensated based on their contribution to reliability—the supply of energy and reserves during periods of reserve shortage. Resources that expect to contribute nothing expect to receive nothing.

Q: Will some resources decide to operate in the market without a CSO?

A: The vast majority of operating resources will operate with a CSO. Existing resources typically are cost-effective because a large portion of their investment costs are sunk. Moreover, taking on the obligation at a level consistent with the unit's expected performance reduces risk. The unit receives a fixed payment for providing its share of performance during shortages and the unit's capacity provides a physical hedge for the obligation.

Nonetheless, there may be a few resources that prefer to operate in the energy market without a CSO. These typically will be resources with high cost, poor performance, or both. Consumers do not pay more as a result of these non-CSO resources. These resources are paid for any reliability they contribute at a rate consistent with the region's desired level of reliability, but they are not relied upon. Rather, the FCM will acquire efficient new capacity to replace the non-participating resources. Over the long-term, assuring reliability in this way still costs net CONE, since we assume the new entry market is contestable.

Q: How will the capacity price vary from year to year under PFP?

A: The capacity market under PFP is expected to have a more stable capacity price than today's market. The reason is that the market will clear at the expected cost of covering the share-of-system obligation during scarcity hours. The obligation has both real benefits for consumers and real costs for suppliers. The clearing price reflects these costs. The costs may change somewhat from year to year, but

are largely invariant to whether there is excess supply in a particular year. Supply will exit or enter at the expected cost of the obligation.

In contrast, without PFP, the capacity price careens from near zero with excess supply to a high price when new entry clears. This increases risk and makes the market vulnerable to the exercise of market power on both sides of the market. As a result, without PFP the capacity price is a much less robust signal for investment incentives. Capacity price volatility has been and remains an important problem that has plagued capacity markets.

Q: Will the PFP design lead to excess entry?

A: No. The capacity market will select the most cost-effective resources up to the target that meets the Installed Capacity Requirement. Additionally, less cost-effective resources could decide to operate in the energy market despite not clearing in the FCA. These resources would be rewarded at the performance payment rate for energy or reserves supplied during scarcity hours. However, since they are less cost-effective than the cleared resources, they would lose money in expectation and decide to exit. Were they to stay in the market, then their contribution to reliability would reduce the number of scarcity hours, thereby further damaging their profitability. This market response to excessive entry drives the market back to the equilibrium where supply equals the Installed Capacity Requirement demand.

Q: How will PFP affect investment incentives?

A: With PFP, all resources face a strong marginal incentive to contribute to reliability by providing energy or reserves in scarcity hours. These strong incentives favorably influence all capital investments that improve performance during stressed system conditions, both in the short run and long run. Suppliers are motivated to make any cost-effective investment in reliability.

Q: How will PFP impact the mix of resources?

A: Favorably. PFP supplements the investment incentives provided by the energy and reserve markets with capacity payments that reflect a resource's contribution to reliability. These combined revenue streams motivate investment in a least-cost portfolio of resources system-wide. The portfolio will consist of a mix of resource types. When there are too few fast-start units, the value of a fast-start unit will be high and more fast-start units will enter. When there are too few baseload units, baseload units will have a high value and enter. Similarly, excessive reliance on one fuel type, such as gas, will increase the possibility of shortages from inadequate gas. This makes units that do not rely solely on gas more valuable and they will enter.

Without PFP, the resource mix suffers from adversely selecting less reliable resources, since contributions to reliability are not rewarded. As such, there are too few fast-start units and other resources that perform well in scarcity hours. The equilibrium result is a less reliable system that does not satisfy the reliability

standard. The reliability shortfall could conceivably be addressed by purchasing additional capacity, but the purchase is not cost effective and might not actually address the problem if the new resources experience the same reliability shortcomings as the existing fleet (*e.g*. dependence on natural gas).

The correct solution is to adopt PFP. This properly rewards contributions to reliability, and thereby motivates investment in the least-cost portfolio for satisfying demand reliably.

VII. CONCLUSION

Q: Can you summarize the main elements of the PFP design and its implied long-run equilibrium properties?

A: Yes. PFP is based on two key elements. The first is a share-of-system supply obligation to provide energy or reserves during shortages. The second is a performance payment rate to settle deviations from the obligation. The performance payment rate is set equal to the net cost of new entry amortized over the expected number of scarcity hours that the resource provides energy or reserves. From these two elements we have the following long-run properties:

- The most cost-effective resources clear in the FCA; that is, the market selects the resources with the lowest cost per MWh of supply in scarcity hours.

- Entry occurs if capacity is needed to satisfy the Installed Capacity Requirement; exit occurs if there is surplus.

- The capacity price does not depend on whether there is excess supply. It remains at the net cost of new entry, which is equal to the expected cost of covering the supply obligation.

Q: Does this conclude your testimony?

A: Yes. This concludes my testimony.

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

Executed on January 17, 2014.

Peter Cramton

Attachment I-1e

Joint Testimony of David LaPlante and Seyed Parviz Gheblealivand

on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER14-_____-000**
and New England Power Pool	**)**	

JOINT TESTIMONY OF DAVID LAPLANTE AND SEYED PARVIZ GHEBLEALIVAND ON BEHALF OF ISO NEW ENGLAND INC.

I. WITNESS IDENTIFICATION

Q: Mr. LaPlante, please state your name, title, and business address.

A: My name is David LaPlante. I am the Vice President of Market Monitoring for ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Mr. LaPlante, please describe your work experience and educational background.

A: I have a Bachelor's degree in statistics from Princeton University and a Master's Degree in City and Regional Planning from Harvard University. I have over 30 years of experience in the energy and utility industry. Between 1989 and 1994, I spent five years supervising and conducting power system reliability studies at the New England Power Pool. I have been working on the deregulation of the wholesale electric industry in New England since 1994. When serious discussions about deregulation of the wholesale electricity market in New England began, I was part of the team that negotiated the contract between the ISO and the New

England Power Pool ("NEPOOL") that led to the creation of the ISO in 1997. I then led the ISO team that worked with NEPOOL to develop and implement the region's first set of wholesale markets in 1999. Following that, I was responsible for the market design portion of the Standard Market Design implemented by the ISO in March 2003. I was integrally involved in the Forward Capacity Market ("FCM") settlement agreement and in the development of the capacity market rules that implement the settlement agreement. In July 2008, I was promoted to Vice President of the Internal Market Monitor (the "IMM") at the ISO.

Q: Dr. Gheblealivand, please state your name, title, and business address.

A: My name is Seyed Parviz Gheblealivand. I am an Economist with Market Development for the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: Dr. Gheblealivand, please describe your work experience and educational background.

A: I have a Bachelor's degree in civil engineering and an MBA from Sharif University of Technology in Tehran, Iran and a Master's Degree and a PhD in Economics from The University of Texas at Austin. The focus on my PhD studies was on Industrial Organization, primarily the theory and empirical study of firm entry and exit, contracts, regulation, and auctions. I joined the ISO's IMM in January of 2011 as Senior Analyst. I was promoted to the position of Economist in October 2013 and transferred to the Markets Development Department in

January, 2014. Prior to joining the ISO, I was a visiting lecturer at the University of Wisconsin-Parkside, during which I taught courses in Industrial Organization and Regulation, and Financial Markets and Institutions.

Since my arrival at the ISO, I have worked on numerous projects in the ISO administered markets, including the energy market, Forward Reserve Market and the FCM. I was the IMM's lead on development of the FCM Pay For Performance project.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q: What is the purpose of this testimony?

A: The purpose of this testimony is to explain why we believe it is imperative that Pay For Performance be implemented and to describe the rule changes related to market monitoring and mitigation that are required to implement it.

Q: Please provide an overview of your testimony.

A: In Section III of our testimony, we explain why we believe that Pay For Performance is a much-needed and essential improvement to the FCM. In Section IV of our testimony, we detail the four main changes to market monitoring and mitigation in the FCM required by the implementation of Pay For Performance. First, under Pay For Performance, only de-list bids from resources associated with

Lead Market Participants[1] that are pivotal may be mitigated by the IMM. For this purpose, the revised rules include a new test to determine if a Lead Market Participant is pivotal. Second, the IMM's de-list bid analysis is being revised to remove the risk adjustment from the calculation of net going-forward costs. As a result, the current "net risk-adjusted going forward costs" bid component is being simplified to "net going forward costs," and the risk premium will be included as a separate component of the de-list bid. It is important to the success of Pay For Performance that resources price the risks they perceive from Pay For Performance in their offer. By making the risk premium a separate component, resource owners will be able to fully describe their risk analysis to the IMM. Third, expected Capacity Performance Payments under Pay For Performance are being added as a distinct de-list bid component. Fourth, the threshold below which resources may leave the capacity market without cost review by the IMM (the "Dynamic De-List Bid Threshold") is being increased from $1.00/kW-month to $3.94/kW-month beginning with the ninth Forward Capacity Auction. Each of these changes, as well as some smaller conforming changes, is discussed in detail below.

III. WHY PAY FOR PERFORMANCE IS A MUCH-NEEDED IMPROVEMENT TO THE FCM

Q: Why do you believe Pay For Performance is necessary?

[1] Capitalized terms used but not otherwise defined in this testimony 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, or the Pay For Performance rules.

A: We believe that the Pay For Performance design is necessary because the current set of wholesale markets will not maintain reliability in New England over the next decade. If Pay For Performance is not adopted, the region is much more likely to suffer a loss of load event, or events, for two reasons. First, the current set of wholesale markets do not send sufficient price signals for owners of resources with Capacity Supply Obligations to make the investments needed to assure their resources can operate reliably when needed. Second, the current capacity market pays resources that do not perform when most needed for reliability, keeping them in the market and preventing new, efficient, and reliable units from entering. Pay For Performance must be put in place now – as some of the region's units reach the end of their lives – so that the wholesale markets send price signals that force poor performing units to exit the market and replace them with new, reliable units. If Pay For Performance is not put in place, the region will struggle to maintain reliability with a generating fleet comprising gas-fired generation that has not invested in means to reliably perform in tight gas situations and poorly maintained, aging, inflexible fossil fueled generation that frequently does not perform when reliability problems arise. As we discuss later, recent events provide strong evidence that the price signals from the current set of wholesale markets are not sufficient to maintain reliability over the next decade.

This is not a new problem. In the 2010 Annual Markets Report, the IMM recommended that changes be made to the definition of a Shortage Event in the current market to strengthen the incentives for capacity resources to perform. The

problems with resources failing to follow dispatch instructions began in 2009 and resulted in the IMM referring to the Federal Energy Regulatory Commission ("FERC" or "Commission") nearly 200 instances of resources failing to follow dispatch instructions. In the 2012 Annual Markets Report, the IMM also recommended reinstating provisions in place during the transition period that take back some or all of a resource's capacity payment if it fails to meet its obligations as a capacity resource. Pay For Performance addresses these problems and recommendations in a comprehensive manner and will result in resources making efficient investments that assure reliability.

Q: Why do you believe that the current set of wholesale markets do not support the investment needed to assure resources with Capacity Supply Obligations operate when needed to maintain reliability?

A: In his testimony, Mr. Brandien describes the wide variety of performance problems that the ISO has been experiencing over the past several years and expresses his concerns about system reliability.[2] The IMM reviews many of these situations to determine whether Tariff violations have occurred and whether rule changes are needed to address the problems. Thus, we are well aware of the problems with the system. The most compelling evidence that the current market signals are inadequate to maintain reliability are the extensive and intrusive regulatory, administrative, and out-of-market actions that the ISO has had to take to track, and understand, the fuel supply of existing resources, to increase the

[2] *See* Testimony of Peter Brandien on behalf of the ISO, submitted with this filing as Attachment I-1b ("Brandien Testimony").

incentives for resources to make their fuel supply reliable, and to enforce the Tariff obligations for resources to have the fuel to follow dispatch instructions if it is physically available.

In the winter of 2009 – 2010, natural gas fired resources began failing to respond to dispatch instructions because of a lack of fuel or an unwillingness to purchase fuel at prevailing prices. In response to this and other problems with natural gas units, the ISO Operations Department was forced to hire experts in the natural gas area, develop the analytical tools to track the natural gas supply coming into New England and to monitor the nominations of natural gas by gas-fired units to determine whether it is reasonable to assume that those units will be able to follow dispatch instructions, especially if they are dispatched beyond their day-ahead schedules or do not have any day-ahead schedule. This detailed knowledge of the gas system is needed so that the ISO can commit oil fired units, out of merit order, if it appears that natural gas resources will not be able to follow dispatch instructions or to start up if committed. These out-of-merit commitments of oil units, while necessary to maintain reliability, undermine and distort the price signals in the Real-Time and Day-Ahead Energy Markets.

As oil prices rose and natural gas prices fell, the region's oil units reduced their on-site oil inventory. The reductions were so severe that the ISO was forced, on several occasions, to operate the resources to manage their fuel supply, rather than according to the economics of the resources or reliability needs. After

experiencing these problems, the ISO started a process of surveying all oil units to know how much oil is in the tanks so that unit commitment and dispatch instructions could be followed. That survey showed that oil inventories were low, that resupply of oil would take weeks rather than days, and that extended operation of most of the oil units in the region would cause them to run out of fuel. All of this confirms the lack of incentives to maintain a reliable fuel supply for resources that take on a Capacity Supply Obligation.

In response to these problems with natural gas and oil availability, the ISO and IMM issued a memo in November of 2012 making clear that generators were required to follow dispatch instructions and to secure the fuel required to follow the dispatch instructions. This memo resulted in a complaint to the FERC by the New England Power Generators Association ("NEPGA") arguing that the view of generator obligation under the Tariff expressed in the memo was incorrect. That complaint started a regulatory process that ultimately ended with a FERC order making clear that generators had an obligation to obtain fuel if it was physically available.[3] The order also made clear that fossil fueled units had an obligation to maintain sufficient on-site inventory so that they would be able to follow dispatch instructions.[4] If market signals were working, the ISO would not have needed to issue the November memo since generators would have found it in their economic interest to secure the fuel needed to follow dispatch instructions.

[3] *New England Power Generators Association, Inc. v. ISO New England Inc.*, 144 FERC 61,157 (2013).

[4] *Id.* at PP 47, 58.

While the regulatory process associated with the obligations memo was ongoing, the blizzard of February 2013 exposed the fuel supply problems facing the region as a result of inadequate market signals. To prevent these problems from re-occurring, in the winter of 2013 – 2014, the ISO implemented an out-of-market program that subsidized the purchase of oil for the region's oil units and paid for the testing of dual-fuel units. It was only in response to this program that many of the region's dual-fuel capable units have become available for dispatch on oil.

Importantly, all of this happened during a period when the New England system had more capacity than needed to meet its Installed Capacity Requirement. In other words, although the ISO easily met its capacity adequacy standards, it experienced significant enough problems maintaining reliability that it was necessary to take a hands-on approach to managing fuel in the region and to take out-of-market actions to assure reliability.

Pay For Performance is necessary to send price signals that will result in generators managing their own fuel supply and making the investments needed to assure system reliability. If Pay For Performance is not implemented, we will see increased intervention, similar to that described above, by the ISO into the market to assure reliability. And even these actions may not be enough to assure reliability when the system runs out of surplus capacity.

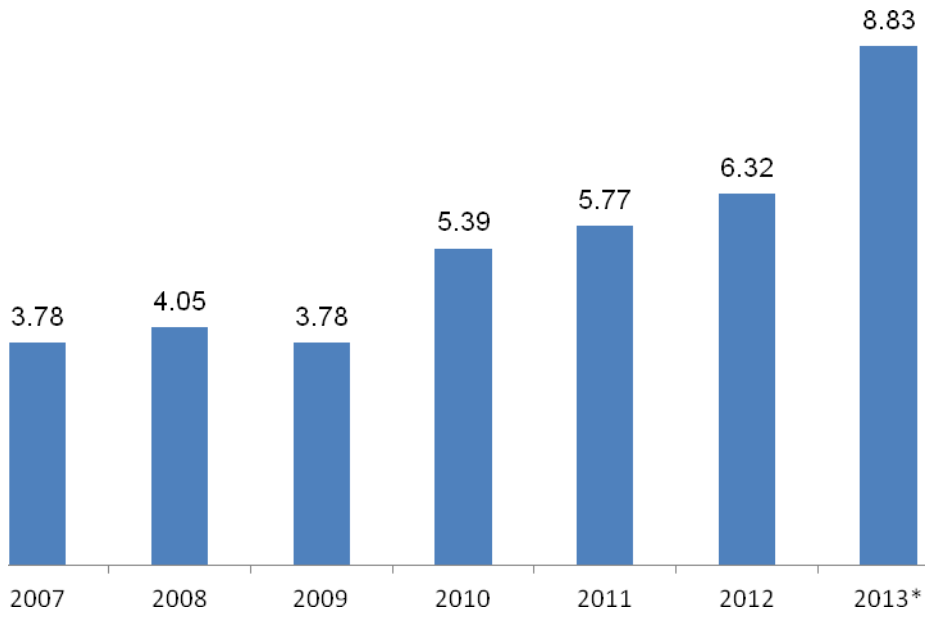
Q: Would these actions have been necessary if the wholesale market design and price incentives were sufficient to assure reliability?

A: No. The ISO does not own these units and should not have to track and influence fuel procurement decisions that are properly the sole province of the resource owner. If the markets were properly designed, the ISO would not have found it necessary to issue a memo to remind generators that they had an obligation under the Tariff to procure fuel and follow dispatch instructions and resource owners would have made the investments to assure that each resource would operate anytime it was dispatched. In short, Market Participants' incentives would be aligned with the ISO's objectives. For example, if the market design was efficient and the proper price signals were in place, then oil units would have found it profitable to maintain sufficient fuel on site to operate whenever needed and natural gas fired units would have had the incentive to make investments in dual-fuel capability or improved gas contracting to assure that they could operate anytime they received a dispatch instruction. The testimony of ISO witnesses Matthew White and Peter Cramton describes in detail the failings of the current market design and how Pay For Performance will remedy them to assure reliability.[5]

Q: What evidence do you have that the current market design is not sending the proper price signals to resource owners to assure that their resources operate reliably when needed?

[5] Testimony of Matthew White on behalf of the ISO, submitted with this filing as Attachment I-1c ("White Testimony") at Sections III and IV; Testimony of Peter Cramton on behalf of the ISO, submitted with this filing as Attachment I-1d ("Cramton Testimony") at 3-18.

A: The most compelling evidence that the current market signals are inadequate to maintain reliability is the increase in forced outage rates over the past several years. This is illustrated by the increase in forced outage rates shown in the chart below, which is also included in Mr. Brandien's testimony.[6] The increase in forced outage rates is evidence that poorly performing resources have not taken actions to maintain their ability to operate reliably. It stands to reason that they did not perceive investments to improve reliability as profitable. If they did, then such actions would have been taken.



Q: What is causing this increase in forced outage rates?

A: This increase in forced outage rates is likely driven by two factors. First, many of the region's oil and coal units are being operated differently than they were designed to operate. These units were designed to be operated all of the time, as

[6] Brandien Testimony at 41.

baseload units, or for five weekdays in a row, in the case of intermediate units. The decrease in natural gas prices and the run up in oil prices that started in 2009 has changed oil units from being operated as baseload or intermediate units to being operated as peaking units. As Mr. Brandien points out in his testimony, these units are large thermal units that perform best when operated for long periods of time.[7] Starting the boilers and heating the units puts stress on the unit. Once the unit is operating it can remain operating and be reasonably reliable, but getting the unit up to its Economic Maximum Limit takes time, especially if the unit has not been operated for weeks or even months. Second, because these units operate infrequently, it is unlikely that resource owners are investing significantly in these units to make them more reliable. At least one representative has stated at NEPOOL Markets Committee meetings that their company has reduced maintenance spending as the unit's capacity factor has fallen. The only investments they are likely to make are those required to meet environmental standards.

Q: Why doesn't the current capacity market design cause resource owners to make investments to make these resources more reliable when they are most needed?

A: Two features of the current FCM design cause resource owners to continue to sell into the market units that perform poorly when they are most needed, rather than making the investments needed to make them reliable. First, under today's FCM rules, a resource cannot lose more through poor performance in the capacity

[7] Brandien Testimony at 26-30.

market than it earns. In other words, without any possible net loss, they have "no skin in the game." Second, their revenue does not depend significantly on performing during the times when resources are needed the most. Consequently, they have no incentive to make investments to improve performance when most needed for reliability.

Q: **When is the probability of a loss of load event the greatest?**

A: There are two periods when the risk of a loss of load event is highest. The first is during periods of high temperatures and high loads in the summer and the second is during winter cold snaps, when usage of natural gas for space heating and electric loads is greatest. In summer, the region is at risk because the high outage rates of the existing fleet of generators will leave the region without enough operating generation to meet its load and operating reserve requirements. On July 19, 2013, the ISO was short of its approximate 2,375 MW operating reserves requirement by about 550 MW, despite having over 2,500 MW more "available" resources than the Installed Capacity Requirement. If there was no surplus above the Installed Capacity Requirement, the IMM has calculated that under the most conservative assumptions, the ISO would have been short of operating reserve by about 1,900 MW before calling on demand resources, forcing the system to operate with about 450 MW of reserves. This is much less than the ISO's first contingency and could lead to the ISO taking emergency actions to maintain system reliability.

In the winter, the ISO may be unable to meet load when the weather is cold and there is a significant, unexpected loss of supply. This causes problems because in cold conditions a high level of uncertainty exists as to whether natural gas availability will support the start up of additional natural gas resources, and many of the region's oil units take at least 12 hours to start. These problems were illustrated in Storm Nemo (in February 2013) and more recently on Saturday, December 14, 2013 when the ISO had to enter OP-4 when non-firm imports to New England were cut by the supplier during the peak load period of the day. Mr. Brandien's testimony explains the problems that the combination of limited natural gas supplies and inflexible resources pose for system operation.[8] In each of these situations, the inability of otherwise "available" generation to get fuel or to respond to stressed system conditions created reliability problems.

Q: Please explain how you determined that, if the ISO had no surplus capacity above the Installed Capacity Requirement, the system would have been 1,900 MW short of its operating reserve requirement of 2,375 MW on July 19, 2013 before calling on its Demand Resources.

A: As noted above, on that day there were about 2,500 MW of capacity above the Installed Capacity Requirement. This consisted of 31,366 MW of installed generation,[9] 1,655 MW of Demand Resources with a Capacity Supply Obligation, and 1,039 MW of Import Capacity Resources with a Capacity Supply Obligation. Comparing this supply with the net Installed Capacity Requirement of 31,552

[8] *See* Brandien Testimony at 6-24.

[9] Based on the total Summer Claimed Capability ratings of generating resources.

MW results in a surplus of 2,508 MW. To estimate what would have happened on that day if there was no surplus, it is necessary to remove approximately 2,500 MW of resources. In this analysis, we removed Salem Harbor, Brayton Point, and Norwalk Harbor stations from the resource mix because they have submitted Non-Price Retirement Requests, which means they will be retiring in the near future. These stations together have a total summer claimed capability of 2,445 MW, thus leaving 28,921 MW of generating capacity when removed. Generator reductions were then calculated based on actual performance over the July peak hour for the remaining resources on the system. Accounting for these outages resulted in 25,184 MW of available generating capacity for the peak hour. For this analysis, it was assumed that the same level of imports from external areas would be available to New England. Therefore, after accounting for the 2,652 MW of imports that were flowing at the time of peak, there were 27,836 MW available on the system prior to accounting for Real Time Demand Resources. As the peak load on this day was 27,379 MW, there were 457 MW available to meet the reserve requirement of 2,375 MW, thus leaving the system with an estimated shortage of approximately 1,900 MW.

Q: Do you believe this analysis understates or overstates the risk to reliability without the Pay For Performance program?

A: We believe it understates the risks because outages, especially outages for the older fossil steam units, have been increasing in the past several years. NERC GADS data show that the fossil steam (including nuclear) Equivalent Forced

Outage Rated demand (EFORd) for resources in New England has increased from 4.27 percent in 2007 to 16.35 percent in 2013 (data through November 30, 2013). If Pay For Performance is not implemented and the performance incentives remain the same, we see little reason for these resources to make investments, or to increase their maintenance budgets, to lower their outage rates since as ISO witnesses Matthew White and Peter Cramton explain in their testimony, the current capacity market provides weak incentives for investments in improved performance because its penalty structure is ineffective in sending the price signals that provide the incentives to invest in improved performance.[10] Thus, without Pay For Performance, outage rates are likely to continue to increase. If outage rates increase, then the analysis shown above becomes optimistic and the risk of having to use rolling blackouts to maintain system reliability also increases.

Q: Why is it especially important to provide improved price signals in New England's wholesale markets to maintain reliability?

A: According to U.S. Energy Information Administration data,[11] less than 3% of the generation in New England is owned or under contract to vertically integrated utilities, which means that 97 percent of the energy comes from merchant-owned generators. These generators make investment and expenditure decisions based on

[10] White Testimony at Section III.B; Cramton Testimony at 14-15.

[11] The data is available at http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,1,0&fuel=g&geo=00fvvvvvvvvvo&sec=8&linechart=ELEC.GEN.ALL-CT-1.A&columnchart=ELEC.GEN.ALL-CT-1.A&map=ELEC.GEN.ALL-CT-1.A&freq=A&start=2001&end=2012&ctype=map&ltype=pin&maptype=0&rse=0&pin=

whether or not they will realize a return on their investments. Consequently, merchant generators will not make investments or expenditures unless the wholesale markets provide returns on them. If there were more vertically integrated utilities in New England, the fact that the price signals in the current markets are insufficient to maintain reliability might be able to be swept under the rug without consequence since vertically integrated utilities have an obligation to keep the lights on and face a variety of non-market pressures that ensure they will put high value on avoiding outages during peak demand periods; merchant generators do not face these pressures to nearly the same degree. Vertically integrated utilities are likely to react in ways that mask the reliability impact of these market inefficiencies, but merchant generators react in ways that fully reflect the inefficiencies of the market. Because of New England's lack of vertical integration, it is especially important that the details of the market design be constructed well and it is no surprise that flaws in the market design appear more quickly in New England than in other regions.

Q: How will Pay For Performance address the problem of increased forced outage rates and increase resource flexibility?

A: As ISO witness Matthew White discusses in more detail, Pay For Performance will address outages and reliability in two ways.[12] Pay For Performance will provide the revenue stream that resources can use to fund the maintenance and investments such as dual fuel equipment to increase the probability that resources will be available when needed. Since revenues from Pay For Performance are

[12] White Testimony at Sections III and IV.

earned in hours in which scarcity conditions occur, Pay For Performance will change the mix of generation in the region to one that is more likely to perform during scarcity conditions. In practical terms, Pay For Performance will encourage resources that are low-cost, flexible, or both, and will discourage resources that are both high-cost and inflexible. It does so because low-cost units are likely to be running most of the time and therefore providing energy during scarcity conditions, while flexible units can be called on when system conditions worsen and more capacity is needed to supply energy and reserves. Both low-cost and flexible resources are likely to earn a high percentage of the Pay For Performance revenues. Inflexible, high-cost resources are the least likely to be running during scarcity conditions and consequently will earn the least amount of revenues under Pay For Performance.

Over time, this re-allocation of revenue will change the resource mix. Resources that earn a high percentage of Pay For Performance revenues will be able to stay in the capacity market at lower capacity prices than resources that earn a low percentage of Pay For Performance revenues. Because their actual capacity revenue will be higher, they will be able to offset any going forward costs not covered by energy market rents. Resources that earn a low percentage of Pay For Performance revenues need higher capacity prices so that the low percentage they actually receive will be able to offset their going forward costs. Thus, the high-cost, inflexible resources will leave the market sooner and they will be replaced by lower-cost or more flexible resources.

In addition, because of the performance revenues earned during scarcity conditions, resources will have incentives to invest to improve their ability to perform in scarcity conditions and lowering their costs, two very desirable attributes.

Q: What do you believe will happen if Pay For Performance is not adopted?

A: System reliability will further deteriorate and more out-of-market ISO intervention will be needed to manage the physical risks to the system. The ISO will be forced to commit oil units out of merit to provide reserves and the likelihood of rolling blackouts will increase due to resources not performing during reserve shortages when they are most needed.

IV. DETAILED DISCUSSION OF PAY FOR PERFORMANCE RULE CHANGES RELATED TO MARKET MONITORING AND MITIGATION

A. Under Pay For Performance, The IMM May Only Mitigate De-List Bids From Pivotal Suppliers

Q: Under the current FCM rules, which de-list bids may be mitigated by the IMM?

A: Under the current FCM rules, Static De-List Bids, Permanent De-List Bids, and Export Bids submitted at prices equal to or above $1.00/kW-month (the current threshold for submission of Dynamic De-List Bids) are reviewed by the IMM to

determine whether the bid is consistent with the resource's net risk-adjusted going forward costs and opportunity costs. Any such bid that is found inconsistent with the resource's net risk-adjusted going forward and opportunity costs is subject to mitigation.

Q: How will this change under Pay For Performance?

A: Under the new Pay For Performance mechanism, the IMM may only mitigate de-list bids at prices above the Dynamic De-List Bid Threshold from resources associated with Lead Market Participants that are found to be pivotal suppliers. (We discuss the change in the Dynamic De-List Bid Threshold from the current $1.00/kW-month to a new value of $3.94/kW-month in Section IV.C below. In this section, we focus on limiting IMM mitigation to de-list bids submitted by pivotal suppliers.)

Q: Why is it appropriate to limit IMM mitigation to pivotal suppliers only?

A: In principle, a Lead Market Participant is pivotal if the applicable capacity requirement cannot be met without some capacity from that Lead Market Participant. A Lead Market Participant is not pivotal if none of its capacity is necessary to meet the applicable capacity requirement (assuming all resources other than those controlled by the Lead Market Participant competitively offer their capacity into the market). Since the market can clear without any of a non-pivotal supplier's capacity, a non-pivotal supplier cannot exercise unilateral market power and profitably set the price at a non-competitive level. Thus, IMM

review of the de-list bids of non-pivotal suppliers is not necessary to assure competitive market outcomes, and it is appropriate to apply mitigation only to the de-list bids of pivotal suppliers whose offers are inconsistent with their going forward costs.

Q: Please explain the process by which de-list bids will be reviewed by the IMM under Pay For Performance.

A: As under the current rules, all de-list bids will be required to include documentation allowing the ISO to review the de-list bid and determine whether it is consistent with the resource's going forward costs. If the resource's Lead Market Participant is pivotal, and the IMM's review of the de-list bid finds the bid consistent with its going forward costs (inclusive of the cost of "taking on the capacity obligation and its associated risks), then the de-list bid will be entered into the Forward Capacity Auction as submitted.

If the IMM's review of a de-list bid from a pivotal Lead Market Participant finds the bid not consistent with its going forward costs, the bid will be rejected. In this case, a revised de-list bid based on the IMM-determined values can be accepted by the participant and used in the auction. While the process for a rejected de-list bid varies somewhat depending on whether the bid is a Static De-List Bid, a Permanent De-List Bid, or an Export Bid, these processes are not being changed from the currently effective rules.

Q: How will the IMM determine if the Lead Market Participant submitting a de-list bid is pivotal?

A: Conceptually, a Lead Market Participant will be considered pivotal if any of the capacity from the existing resources controlled by that Lead Market Participant is needed to satisfy the capacity requirements either system-wide or in an import-constrained Capacity Zone.

Q: Please explain how the pivotal supplier determination will work system-wide.

A: As stated in the revised FCM rules, a de-list bid will be associated with a pivotal supplier if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of: (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW.

Expressed mathematically, a Lead Market Participant is pivotal system-wide if the following inequality is true:

$$(\text{Total Capacity} - \text{NICR}) \leq \max[(\text{LMP Capacity} \times 1.1), (\text{LMP Capacity} + 200)]$$

Where:

- Total Capacity is the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area;
- NICR is the Installed Capacity Requirement (net of HQICCs) for the applicable Capacity Commitment Period; and
- LMP Capacity is the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant.

These terms are subject to adjustments as described in further detail below.

Q: Why is it the difference between the total amount of existing capacity minus the Installed Capacity Requirement (net of HQICCs) that is compared to the Lead Market Participant's capacity?

A: If the total amount of existing capacity is greater than the Installed Capacity Requirement (net of HQICCs), then the difference between the two will be a positive value that represents the amount by which the system is "long." In that case, for a supplier to be pivotal, it would have to control an amount of capacity equal to or greater than the excess amount in order for some of its capacity to be needed to satisfy the requirement. Otherwise the resource is not pivotal. If the amount of existing capacity is less than the Installed Capacity Requirement (net of HQICCs), the difference between the two is the amount by which the system is "short." In that case, all capacity is needed to satisfy the requirement and all suppliers are pivotal.

Q: Will any adjustments be made to the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area?

A: Yes. The total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated. Pending Non-Price Retirement Requests and Permanent De-List Bids represent capacity that is highly likely to be removed from the capacity market in the Capacity Commitment Period, and hence is properly excluded from the total amount of capacity in making the pivotal supplier determination. However, this exclusion will not apply to Non-Price Retirement Requests and Permanent De-List Bids submitted by the Lead Market Participant for the resource being evaluated. It is appropriate to include such amounts in the quantity of total existing capacity because its removal is within the control of the Lead Market Participant and exclusion of such amounts could lead to situations where the IMM fails to identify a pivotal supplier with potential market power.

Q: Please provide an example of how a pivotal supplier would be found non-pivotal if its Non-Price Retirement Requests are excluded from the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area.

A: Assume that the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area is 25,250 MW and that the net Installed Capacity Requirement is 22,000 MW. Lead Market Participant A has 3,000 MW of summer Qualified Capacity. Using the formula provided above, this participant is pivotal at the system level because the following expression is true:

$$(25{,}250 - 22{,}000) \leq \max[(3{,}000 \times 1.1), (3{,}000 + 200)].$$

Assume next that Participant A decides to submit Non-Price Retirement Requests in the amount of 2,000 MW. If the pivotal supplier test excludes this amount from the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area (that is, if the IMM assumes that the Non-Price Retirement Requests are accepted by the ISO), then the total summer Qualified Capacity is reduced from 25,250 MW to 23,250 MW. Participant A's summer Qualified Capacity is reduced from 3,000 MW to just 1,000 MW. Under these assumptions, Participant A would not be pivotal at the system level because the following expression is *not* true:

$$(23{,}250 - 22{,}000) \leq \max[(1{,}000 \times 1.1), (1{,}000 + 200)].$$

This becomes problematic if Participant A's Non-Price Retirement Request is subsequently rejected by the ISO, which would make this participant again pivotal. To address this problem, in determination of Participant A's pivotal supplier status, the IMM will assume that its Non-Price Retirement Requests are rejected in determining the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area. If this is not done,

and the Non-Price Retirement Requests are accepted, then Participant A's other resources may become pivotal and set the price at non-competitive levels.

Q: Please provide an example of how a pivotal supplier might be found non-pivotal if Non-Price Retirement Requests from other Lead Market Participants are included in the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area.

A: Assume again that the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area is 25,250 MW and that the Net Installed Capacity Requirement is 22,000 MW. As in the example above, assume that Participant A has 3,000 MW of summer Qualified Capacity, and submits Non-Price Retirement Requests in the amount of 2,000 MW. Another Lead Market Participant, Participant Z, has 1,500 MW of summer Qualified Capacity. In evaluating whether Participant Z is pivotal, it is appropriate to assume that Participant A's Non-Price Retirement Requests are accepted (that is, the amount of Participant A's Non-Price Retirement Requests is not included in the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area). Using the formula provided above, this participant Z is pivotal at the system level because the following expression is true:

$$(23{,}250 - 22{,}000) \leq \max[(1{,}500 \times 1.1), (1{,}500 + 200)].$$

If, on the other hand, the IMM assumed that Participant A's Non-Price Retirement Requests are rejected, then the IMM's pivotal supplier test would incorrectly identify Participant Z as non-pivotal at the system level because the following expression is *not* true:

$$(25{,}250 - 22{,}000) \leq \max[(1{,}500 \times 1.1), (1{,}500 + 200)].$$

These examples demonstrate that, to identify all potentially pivotal suppliers, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area must exclude the amount of capacity subject to Non-Price Retirement Requests, other than those of the Lead Market Participant being reviewed, which must be included in the total.

Q: Why is it appropriate to treat Permanent De-list Bids in the same manner as described above for Non-Price Retirement Requests?

A: Pursuant to Section III.13.1.2.3.1.5.2 of the Tariff, a Permanent De-List Bid that has been rejected by the IMM may be resubmitted as a Non-Price Retirement Request after such rejection. So any pending Permanent De-List Bid has the same potential impact on the total capacity amounts as a Non-Price Retirement Request. For this reason, it is appropriate to apply the same treatment to Permanent De-list Bids.

Q: How will the IMM determine the Installed Capacity Requirement (net of HQICCs) to use in the pivotal supplier analysis?

A: The IMM shall use the best available estimates of those values available at that time it conducts the pivotal supplier analysis, which is in the third quarter of each year. The IMM shall publish those estimated values on the ISO website no later than the date that the qualification determination notifications are issued. The determination of the Installed Capacity Requirement and related values go through the stakeholder process and are ultimately approved by the Commission. Final approval of the Installed Capacity Requirement and related values by the Commission occurs after the issuance of the qualification determination notifications in which the IMM must notify resource owners of the determinations regarding their de-list bids. Consequently, the IMM must perform the pivotal supplier test before the Installed Capacity Requirement and related values are approved.

Q: Will any adjustments be made to the total amount of existing capacity controlled by the Lead Market Participant?

A: Yes. For purposes of the system-wide pivotal supplier determination, the IMM will use the greater of: (a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW. This is expressed mathematically by the max operator in the formula above.

Q: Why is the IMM increasing the capacity controlled by the Lead Market Participants in this manner?

A: It is important to ensure that all bids from potentially pivotal suppliers are subject to mitigation. Because the Installed Capacity Requirement (net of HQICCs) and related values in the pivotal supplier determination will not be not approved by the Commission at the time the pivotal supplier determination must be completed, it is reasonable to err on the conservative side by building into the design a small buffer or margin of safety to ensure that de-list bids from Lead Market Participants "near the line" – that could potentially be pivotal once the Installed Capacity Requirement (net of HQICCs) is final – will also be subject to mitigation. This is accomplished by adding a small amount to the Installed Capacity Requirement (net of HQICCs). If this buffer were not included, and the final Installed Capacity Requirement (net of HQICCs) were higher than previously estimated, then a pivotal supplier might incorrectly appear non-pivotal at the time of the IMM's evaluation.

Rather than increase the Installed Capacity Requirement, the pivotal supplier test increases the amount of capacity controlled by the Lead Market Participant. Increasing the amount of capacity controlled by the Lead Market Participant is mathematically equivalent to increasing the Installed Capacity Requirement (net of HQICCs) by the same amount. This approach allows the adder to be somewhat tailored to the amount of capacity controlled by the Lead Market Participant. The adder is the greater of: (a) the Lead Market Participant's existing capacity

multiplied by 1.1; and (b) the Lead Market Participant's existing capacity plus 200 MW. For Lead Market Participants with less than 2,000 MW, the 200 MW adder will control (that is, it will be the greater of the two values, and hence will be used in the pivotal supplier determination). For Lead Market Participants with more than 2,000 MW, the 1.1 multiplier will control.

The specific values chosen (multiplying by 1.1 or adding 200 MW, respectively) appropriately balance the uncertainties with respect to the Installed Capacity Requirement (net of HQICCs) at the time the pivotal supplier determination must be made and the IMM's objective to avoid mitigating resources that are unlikely to possess market power.

Q: Please explain how the pivotal supplier determination will work in an import-constrained Capacity Zone.

A: In an import-constrained Capacity Zone, the pivotal supplier determination will work largely in the same manner as it does system-wide, except that zonal values are used instead of system-wide values for the total amount of existing capacity, the capacity requirement, and the amount of existing capacity controlled by the Lead Market Participant. Specifically, as stated in the revised FCM rules, a de-list bid from a resource in an import-constrained Capacity Zone will be associated with a pivotal supplier if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the

import-constrained Capacity Zone is less than or equal to the greater of: (a) the amount of capacity from all of the Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and (b) the amount of capacity from all of the Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

Expressed mathematically, a Lead Market Participant is pivotal in an import-constrained Capacity Zone if the following inequality is true:

$$(\text{Zonal Capacity} - \text{LSR}) \leq \max[(\text{LMP Capacity} \times 1.1), (\text{LMP Capacity} + 100)]$$

Where:

- Zonal Capacity is the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone;
- LSR is the Local Sourcing Requirement for the import-constrained Capacity Zone for the applicable Capacity Commitment Period; and
- LMP Capacity is the amount of capacity from all of the Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant.

These terms are subject to the same adjustments as described above with respect to the system-wide pivotal supplier determination.

Q: Other Than Using Applicable Zonal Values, Does The Pivotal Supplier Determination In An Import-Constrained Capacity Zone Differ From The System-Wide Approach?

A: The only other difference is that system-wide, the amount of capacity from the Lead Market Participant is increased to the greater of the Lead Market Participant's existing capacity multiplied by 1.1 and the Lead Market Participant's existing capacity plus 200 MW, while in an import-constrained Capacity Zone, the adder in the second alternative is 100 MW instead of 200 MW. This smaller value reflects the smaller amount of variation in capacity in an import-constrained Capacity Zone than system-wide. The IMM believes that this smaller value is reasonable because each import-constrained Capacity Zone is only a portion of the system and uncertainty about the Local Sourcing Requirement is only a portion of that about the Installed Capacity Requirement.

Q: Why are new capacity resources excluded from consideration in both the system-wide and import-constrained Capacity Zone pivotal supplier determination?

A: In principle, a MW of power from a new capacity resource is a perfect substitute for a MW of power from an Existing Capacity Resource. There is no reason to include new capacity in the pivotal supplier determination, however, because

including capacity from new resources would not change the pivotal status of the Lead Market Participant of the new resource from pivotal to non-pivotal. But it could change the pivotal status of *other* participants from pivotal to non-pivotal. In other words, some participants that are in fact pivotal might be flagged as non-pivotal if the capacity from new resources is included in the determination of pivotal suppliers.

Q: Please explain why including new capacity of a pivotal Lead Market Participant does not make that participant appear non-pivotal?

A: In its simplest form, a participant's pivotal status depends on whether the capacity requirement can be met without that participant's capacity. A participant is pivotal if the difference between total quantity supplied and the quantity supplied by that participant is smaller than the quantity demanded. An additional MW of capacity by a participant increases both the total quantity supplied, and quantity supplied by that participant, leaving the difference intact. Hence, if a pivotal participant adds new capacity, it adds to the total quantity supplied as well as the quantity supplied by that participant at the Forward Capacity Auction Starting Price. The difference between these two variables, and as a result, the participant's pivotal status, will not change after including new capacity in the calculations.

Q: **Please explain how including new capacity of a participant could make other, potentially pivotal Lead Market Participants, appear non-pivotal in the test?**

A: Lead Market Participants submitting new capacity offers can withdraw their offers between the qualification deadline and the Forward Capacity Auction. Consider a situation where total existing capacity in the system is 50 MW short of the Installed Capacity Requirement. In this situation, all resources are pivotal. Now consider two participants, one that has 100 MW of existing resources (Participant A), and another one with only 20 MW of existing capability (Participant B). Participant A also has 400 MW of new capacity, which can be withdrawn after the pivotal supplier determination is made.

If the IMM includes Participant A's new capacity in determining whether Participant B is pivotal, the system will be long 350 MW and Participant B will appear to be not pivotal. As non-pivotal, Participant B would be exempt from mitigation by the IMM. If Participant A then later withdraws its new capacity, Participant B is indeed pivotal, but could proceed to the auction with an unmitigated offer that could set the market price.

Q: Is it possible that the IMM's pivotal supplier test results in "false positives," that is, Lead Market Participants that are in fact non-pivotal, but are identified as pivotal by the IMM?

A: Yes. In the scenario above, for example, if Participant A does not withdraw its 400 MW of new capacity, Participant B would have been identified as pivotal, but would have been in fact non-pivotal. The pivotal supplier test necessarily involves this tradeoff, however, and in its effort to guard against the exercise of market

power, the IMM believes there is far less risk to competitive outcomes and market integrity in flagging some non-pivotal suppliers as pivotal than in failing to flag some actually pivotal suppliers. The harm to the owner of the resource in the case of such "false positives" is minimal. Such a resource is not automatically mitigated; it is simply subject to potential mitigation if the submitted de-list bid is inconsistent with its going forward costs. If the de-list bid is consistent with its costs, there is no mitigation. The potential harm from failing to identity an actually pivotal supplier is far more serious. Unmitigated de-list bids from truly pivotal suppliers can inappropriately set the auction price significantly higher than it would have been if all offers are competitive. For these reasons, the pivotal supplier test is calibrated to identify virtually all potentially pivotal suppliers, even at the (minimal) risk of a false positive.

Q: Does the pivotal supplier test apply to a Lead Market Participant controlling only a single resource or only controlling a small amount of capacity?

A: Yes. The number or size of the resources controlled by a Lead Market Participant is not relevant to the pivotal supplier determination. A Lead Market Participant can be pivotal if only a small amount of its capacity is needed, regardless of the overall number and size of resources controlled. Furthermore, an exception based on the number or size of resources could provide an incentive to spin-off a pivotal generation asset for the purpose of exercising market power. When the amount of existing capacity is smaller than or equal to the applicable capacity requirement,

all Lead Market Participants, large or small, and irrespective of the number of resources they control, are pivotal.

B. Changes to the IMM's Review of De-List Bids

Q: At a high level, how is the IMM's review of de-list bids changing under Pay For Performance?

A: Under the current rules, there are two main components of a de-list bid that are reviewed by the IMM: net risk-adjusted going forward costs, and opportunity costs. The rule revisions presented here instead break the de-list bid into four distinct components for IMM review: net going-forward costs, expectations about the resource's Capacity Performance Payments, risk premium assumptions, and opportunity costs. Each of these four components will be discussed below, but the notable changes here are: (i) the removal of the risk adjustment from the net going-forward cost calculation and the creation of a distinct risk premium component, because risk assessment is an important piece of developing an offer under Pay For Performance; and (ii) the addition of a new component for expectations about Capacity Performance Payments.

Q: Will resources continue to have the ability to submit de-list bids that vary by block for a single resource?

A: Yes. Presently, resources can submit bids in the Forward Capacity Auction with different prices for one portion of the resource's capacity, or "block," than for

additional portions of the resource's capacity. For example, a generator with 100 MW of capacity can submit one bid price for the first 90 MW block of its capacity, and a second, higher bid price for the upper 10 MW block of its capacity. In the capacity auction, a resource that bids in this way may clear neither block, only the first 90 MW block, or both blocks, based on its bids and the relevant Capacity Clearing Price.

Under Pay For Performance, it is more important for a resource to be able to submit bids by block, since factors affecting the resource's performance during the Capacity Commitment Period may vary by block. For example, if a resource owner is risk averse, and believes that there is a greater risk that higher output blocks are not able to perform as reliably as lower blocks, it can price this higher risk into the upper blocks. That is economically desirable, as it means the auction is less likely to clear, and the region less likely to rely upon, the blocks of resources that owners believe are less reliable. In addition, the going forward costs of higher blocks may be greater than lower blocks. Allowing de-list bids to be broken into blocks permits this to be reflected in a resource's offer.

1. Net Going Forward Costs

Q: Why is the risk adjustment being removed from the net going-forward costs calculation and instead being reflected in a distinct risk premium bid component?

A: Under Pay For Performance, risks faced by resources are very different that those in the current market. Risks under Pay For Performance vary greatly depending on several factors, including the size of a participant's portfolio, its risk tolerance, and uncertainty about the number of hours with Capacity Scarcity Conditions during the Capacity Commitment Period three years in the future. A risk adjustment is included in the current net risk-adjusted going forward cost formula, but that formula is overly simplistic for use under Pay For Performance since it only reflects unit availability. Additionally, since each participant's risk tolerance and its method for assessing risk are likely to be different, it is not possible to develop a single formula that would enable all Lead Market Participants to accurately reflect their risk preferences. Therefore to permit each participant to thoroughly represent and fully explain their risk premium, under Pay For Performance the risk adjustment is being removed from the net going-forward costs formula, and is being replaced by a separate risk premium component of the bid. Using a formula for calculating the risk premium would force all participants to use the same methodology for calculating their risk premium; this seems an unwarranted intrusion into an area that should be the prerogative of the resource owner.

Q: How will the net going-forward cost calculation change?

A: The current net risk-adjusted going forward cost calculation in the Tariff is:

$$NRAGFC = \frac{\left[\frac{GFC}{1-EFORd} + RF - (IMR - PER)\right] \times InflationIndex}{Q_{summer} \times 12}$$

Where:

- GFC is the annual going forward costs (in dollars);
- EFORd is the Equivalent Forced Outage Rate of the unit;
- RF is the risk factor of the unit (in dollars);
- IMR is the annual infra-marginal rents (in dollars);
- PER is the resource-specific annual peak energy rents (in dollars); and
- InflationIndex is the inflation index. InflationIndex = $(1 + i)^4$ where i is the 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period.

The variables in and application of this formula are defined in more detail in Section III.13.1.2.3.2.1.2 of the Tariff. The terms in this formula reflecting the risk adjustment are (1-EFORd) and RF. The term (1-EFORd) is the percentage of time that a unit that is in demand is in forced outage. A higher EFORd for a resource means that it is available during fewer hours in the Capacity Commitment Period and is more likely to be exposed to the Shortage Event penalties (under the current Tariff provisions). Risk Factor, RF, takes several risk-related factors such as cost of replacing a Capacity Supply Obligation if a resource having that obligation experiences a significant decrease in its capability.

As explained above, these two variables are being removed from the going-forward costs formula, and instead all risk related calculations will be included in a separate risk-premium de-list bid component, which is discussed below. The net going-forward costs formula after removal of the risk-related terms is:

$$NGFC = \frac{GFC - (IMR - PER) \times InflationIndex}{Q_{summer} \times 12}$$

Except for removal of the risk adjustment terms, the other variables will remain largely unchanged. These other variables have been in place and calculated successfully by participants for several years.

Q: You said that the remaining variables in the net going-forward costs formula will be "largely unchanged." Other than removal of the formula terms related to risk adjustment, are there any other changes to the net going-forward costs calculation?

A: The revisions also include a minor change to the "Inflation Index" term in the net going-forward costs calculation. That term is currently based on the 1-Year Constant Maturity Treasury Rate. After reviewing issues with the current inflation index and studying several historical and forward looking indices, the IMM has determined that the expected 4-year inflation prediction published monthly by the Federal Reserve Bank of Cleveland is the most comprehensive forward looking index for changes in the costs of capacity suppliers. Otherwise, there are no further changes to the net going-forward cost formula or the definitions of the formula terms.

2. Risk Premium

Q: How does the IMM view the risk premium in general?

A: The IMM views the risk premium as an essential part of each participant's offer. The future number of scarcity hours, the Capacity Balancing Ratio, and a resource's performance during the commitment period are all uncertain when a resource owner submits a new supply offer or a de-list bid. In making decisions about future investments and expenditures, we expect that resource owners will consider that uncertainty. Therefore, it is necessary for their de-list bids to also include that uncertainty so that the bids accurately reflect the price that resources require to participate in the market and meet the associated obligations.

More technically, the IMM defines the risk premium as the amount of expected profit a participant would be willing to forego in order to avoid some of the "downside" risk of losing money in the capacity market. Participants form their expectations about relevant market variables, calculate their expected profit-maximizing bid, and then add a premium depending on how much of the downside they want to avoid. Adding any risk premium to an expected-profit maximizing bid lowers the probability of clearing in the Forward Capacity Auction by enough that it will reduce the resource's expected profit. However, if the resource still clears in the auction, it may increase the resource's Capacity Base Payment – and therefore lowers its risk of losing money during the Capacity Commitment Period.

Q: What are the possible noncompetitive behaviors that can be concealed using the risk premium?

A: Adding a risk premium to an expected profit-maximizing bid is consistent with competitive behavior. However, a resource with significant market power that is unconcerned about a portion of its portfolio *not* clearing in the Forward Capacity Auction could use a risk premium on that portion of its portfolio to increase the market clearing price and benefit its resources that remain in the auction. For this reason, the IMM will review the information supporting the risk premium component of the de-list bid of pivotal suppliers.

Q: What are some of the risks faced by participants under Pay For Performance?

A: Under Pay For Performance, resources face a number of uncertainties that could result in losing money by acquiring a Capacity Supply Obligation and, under the same outcomes, not losing money if they did not acquire a Capacity Supply Obligation. For example, resources face risks regarding system conditions. Most importantly for Pay For Performance, the number of hours of scarcity conditions and the average Capacity Balancing Ratio during the Capacity Commitment Period are uncertain future conditions when de-list bids are due. The more Capacity Scarcity Conditions that occur and the higher the Capacity Balancing Ratio, the more money will flow through the Pay For Performance mechanism. All resources, but especially poorly performing ones, will want to account for this uncertainty in formulating their bids. In formulating its bid, a resource owner is likely to start with an expected number of Capacity Scarcity Condition hours and an expected Capacity Balancing Ratio and calculate its "base bid" on the basis of

those expectations. However, all resources will recognize that there could be more or fewer Capacity Scarcity Conditions, and a higher or lower Capacity Balancing Ratio than they expect.

A poorly performing resource is likely to be particularly concerned that it may experience performance charges that are greater than its "base bid" – that is, experience a net loss in FCM settlement – if there are more scarcity conditions or a higher Capacity Balancing Ratio that expected. To compensate for this risk, such resources are likely to add a risk premium to their bid. Resources also face risks with respect to their individual performance. If, for example, a resource has a significant decrease in its capability during the commitment period, it would have to either pay another resource to cover its obligation, or face the potential for additional losses during Capacity Shortage Conditions. It is to be expected that poorly performing resources, in particular, will include a risk premium in their bids; that is consistent with competitive pricing given the performance risk they face, and is economically appropriate because it leads the Forward Capacity Auction to be less likely to clear resources that the owners' expect may perform poorly.

Q: Please describe the new risk premium component of a de-list bid.

A: With the risk adjustment removed from the net going-forward cost calculation, the Tariff revisions implementing Pay For Performance include a new Section III.13.1.2.3.2.1.4 that details the separate risk premium component of a de-list bid.

That section states that the Lead Market Participant for a resource submitting a de-list bid that is to be reviewed by the IMM shall also provide documentation separately detailing any risk premium included in the bid. Such documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during scarcity conditions. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs may be included in the risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the FCM is consistent with the participant's corporate risk management practices. The IMM will review the affidavit and the risk analysis, compare it to those submitted by other participants, and ask for additional information if necessary.

Q: Why is this approach preferable to the formula-based approach in the currently effective version of the FCM rules?

A: The formulaic approach in the current rules is based on the risks in the current market design. Implementation of Pay For Performance changes the risks, making the current formula no longer adequate. The calculation of risk under Pay For Performance is more complex and is affected by several factors. The IMM believes that each company should evaluate their risks based on their own

methodology rather than requiring companies to use the same method prescribed by the IMM.

Q: How will the IMM evaluate the risk premium component of a de-list bid?

A: The IMM will evaluate each de-list bid in two ways. First, for units that are part of a multi-unit portfolio, the IMM will ascertain whether the risk premium requested for each of the units in the portfolio reflect consistent assumptions on key parameters affecting risk across the portfolio, including the expected number of hours of Capacity Scarcity Conditions. This may require the IMM to ask for information from a participant about other resources it owns for which it has not submitted de-list bids to determine if applying the assumption used in the submitted bids to other units would result in going forward costs higher than the Dynamic De-List Bid Threshold. If this occurs, the IMM will likely discuss these results with the participant to understand why de-list bids were submitted for the selected units and not others.

The second way in which the IMM will evaluate the risk premium portion of de-list bids is by comparing the risk premia across participants. If all of the risk premia are within the same range, then that would support a finding of a reasonable risk premium consistent with competitive market behavior. Participants with risk premium submittals that are noticeably outside of the range of reasonableness established by all of the risk premia taken together will likely be asked for further explanation.

The results of these analyses will be used by the IMM to determine if the risk premium is reasonable and consistent with the resource's net going-forward costs.

3. Expected Capacity Performance Payments

Q: Aside from the changes to the risk adjustment, you stated that another change to the IMM's review of de-list bids under Pay For Performance is the addition of a new component for expectations about Capacity Performance Payments. Please describe this change.

A: Pursuant to the revised rules, the Lead Market Participant for a resource submitting a de-list bid shall also provide documentation separately detailing its expected Capacity Performance Payments for the resource. This documentation must include assumptions regarding the Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

Q: Why is the expected Capacity Performance Payments being made a separate component of the de-list bid?

A: The assumptions supporting a resource's estimate of its expected Capacity Performance Payment will enable the IMM to evaluate whether the resource's bid is competitive.

Q: How are a resource's expected Capacity Performance Payments determined?

A: A resource's Capacity Performance Payment for a Capacity Commitment Period is the difference between the amount of energy and reserves it was obligated to provide during Capacity Scarcity Conditions, based on its share-of-system financial performance obligation, and the amount of energy and reserves it actually supplies times the Performance Payment Rate. This is described in detail in Section IV of Dr. White's testimony.[13] The details of the calculation are in revised Section III.13.7.2 of the Tariff.

Q: What is the significance of a resource's expected Capacity Performance Payments?

A: From the IMM's perspective, the significance of a resource's expected Capacity Performance Payments is their importance in determining a competitive bid for the resource. For most resources, a competitive bid will simply be the opportunity cost of taking on a Capacity Supply Obligation. Each resource will have its own estimate of that opportunity cost. This component of the de-list bid will enable the IMM to review the assumptions used by the resource in calculating its opportunity cost. For a minority of resources, however, a bid based simply on the opportunity cost of taking on a Capacity Supply Obligation will not be enough to cover their net going forward costs. The competitive bid for those resources must include an adder to their estimate of opportunity costs large enough to assure that they cover all of their going forward costs during the commitment period.

[13] White Testimony at Section IV.C.

The assumptions used in the calculation of the resource's expected Capacity Performance Payments enable the IMM to determine the resource's opportunity cost of taking on a Capacity Supply Obligation. Under Pay For Performance, a resource that has not taken on a Capacity Supply Obligation will also be paid the Capacity Performance Payment Rate multiplied by the amount of energy and reserves that it provides during a Capacity Scarcity Condition. The testimony of Drs. White and Cramton explain the economic importance of this aspect of the Pay For Performance design.[14]

Resources that do take on a Capacity Supply Obligation are selling forward their pro-rata share of the system's energy and reserve requirements during Capacity Scarcity Conditions. In other words, in exchange for the Capacity Base Payment, they agree to provide their share of the system's requirements during Capacity Scarcity Conditions in the commitment period. For a resource to take on this obligation, it will want to receive at least the amount of money it could have received by not taking on a Capacity Supply Obligation – that is, its opportunity cost.

The difference between a resource's Capacity Performance Payment with a Capacity Supply Obligation and without a Capacity Supply Obligation is the Capacity Performance Payment Rate times the expected number of hours of Capacity Scarcity Conditions times the expected Capacity Balancing Ratio. This is the resource's opportunity cost of acquiring a Capacity Supply Obligation, and

[14] White Testimony at 67-69; Cramton Testimony at 23-24.

therefore is the *minimum* payment that a resource will require to take on a Capacity Supply Obligation. The resource owner's expectations of the number of hours of Capacity Scarcity Conditions and the Capacity Balancing Ratio enable the IMM to evaluate the resource's opportunity cost of taking on a Capacity Supply Obligation.

A resource's expected revenues under Pay For Performance must be considered in evaluating its de-list bid to determine if these revenues are sufficient to cover the resources going-forward costs net of energy revenues. For a resource to take on a Capacity Supply Obligation, it must expect that it will earn enough money through its participation in the FCM to cover its net going forward costs. The going forward cost calculation described in Section IV.B.1 above shows whether or not a resource will earn enough revenue from the energy and ancillary services markets to cover its going forward costs. If a resource earns enough revenue from the energy and ancillary services markets to cover its going forward costs, then its competitive bid in the capacity market is simply its opportunity cost, as described above.

If a resource does not earn enough revenue from the energy and ancillary services markets to cover its going forward costs, then additional calculations must be done to determine whether its competitive bid in the capacity market is simply its opportunity costs or if the bid has to be increased to assure recovery of its net going-forward costs. The first such calculation is to determine whether the

resource would earn enough revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) to cover its net going-forward costs. If it does, the resource would not *need* to assume a Capacity Supply Obligation to receive Capacity Base Payments to cover its net going-forward costs and consequently the only cost it incurs in taking on a Capacity Supply Obligation is its opportunity cost. If the first calculation shows that the expected revenue from Capacity Performance Payments (absent a Capacity Supply Obligation) is not enough, then a second calculation has to be done to determine how much additional revenue is needed. This calculation is done by subtracting the Capacity Performance Payments (absent a Capacity Supply Obligation) from the net going-forward costs. This difference has to be added to the resource's opportunity cost to assure that it will be able to cover both its share of the system financial obligation and its net going-forward cost if it receives a Capacity Supply Obligation.

Q: How will the IMM evaluate the Lead Market Participant's expectations regarding the applicable Capacity Balancing Ratio, the number of hours of Capacity Scarcity Conditions, and the resource's performance during Capacity Scarcity Conditions?

A: For the Capacity Balancing Ratio and the number of hours of Capacity Scarcity Conditions, the IMM will rely on two sources. The first source is the ISO's estimates of these two variables depending on the expected nature of Capacity Scarcity Conditions (whether they are expected in the summer or winter) and the

total amount of capacity available in the system. The number of hours with Capacity Scarcity Conditions is inversely related to the amount of excess supply in the system. The second source for reasonable estimates of these variables is the range that is established by other Static De-List Bid and Permanent De-List Bid submissions. The IMM can use other Static and Permanent De-List Bid submissions because (unlike resource-specific performance) the Capacity Balancing Ratio and the number of hours with Capacity Scarcity Conditions affect all resources. We will treat these estimates in the same way as estimates of the risk premium. Participants with submittals that are noticeably outside of the range of reasonableness established by the universe of submissions will likely be asked for additional information. In addition, and similar to evaluation of risk premia, the IMM may ask for information from a participant about resources that belong to that participant that have not submitted de-list bids to determine if applying the assumptions used in the submitted bids, particularly on Capacity Balancing Ratio and the expected number of scarcity conditions, to other resources would warrant submission of Static or Permanent De-List Bids for those other resources. If this occurs, the IMM will likely discuss these results with the participant to understand why de-list bids were submitted for the selected resources and not others.

For resource performance during Capacity Scarcity Conditions, the IMM can rely on years of data on existing resources. If a participant believes that its performance may be significantly different than what has been observed in the

past, it can explain this in its Static De-List Bid and Permanent De-List Bid submission or in response to IMM inquiries.

Q: In the discussion about risk premium above, you mentioned that resources face uncertainties with respect to the future number of reserve deficiency hours. In your opinion, should these uncertainties affect the expected Capacity Performance Payments analysis?

A: Such uncertainties should not enter the expected Capacity Performance Payment calculations. Expected Capacity Performance Payments should only include the *expected* values of the number of reserve deficiency hours and the Capacity Balancing Ratio. The uncertainties around these variables will play an important role in the calculation of the risk premium.

4. Opportunity Costs

Q: What changes are being made to the opportunity costs component of the de-list bid?

A: Unlike risk premia and expected Capacity Performance Payments, opportunity costs are already a de-list bid component under the current FCM rules. To conform with the revisions described above, however, some minor changes are being made to the opportunity costs provisions. First, the provision is being reworded to clarify that opportunity costs should only include costs not reflected in the net going-forward costs, expected Capacity Performance Payments, or risk

premium components of the bid. This is necessary to ensure that costs are appropriately categorized and that there is no double-counting. Second, references to quantifiable risk in the current opportunity cost provisions are being deleted. This is because any risk elements should instead be included in the new risk premium de-list bid component. Third, the revisions remove redundant procedural language from the opportunity costs provisions.

C. Increasing the Dynamic De-List Bid Threshold

Q: What is the Dynamic De-List Bid Threshold?

A: In the current FCM, there are two types of de-list bids that enable a resource to leave the capacity market for a single Capacity Commitment Period. Resources that wish to leave the market at prices equal to or above $1.00/kW-month, must submit Static De-List Bids in advance of the Forward Capacity Auction for review by the IMM. If resources wish to leave the market at prices below $1.00/kW-month, they may submit a Dynamic De-List Bids during the Forward Capacity Auction without review by the IMM.

Throughout the currently effective FCM rules, this $1.00/kW-month threshold between the two types of de-list bids is spelled out as "$1.00/kW-month." Whenever the threshold for submission of Dynamic De-List Bids is changed, each of these many instances must be updated in the Tariff. For simplification, the revised rules submitted here replace each of those instances with a new defined

term, the "Dynamic De-List Bid Threshold." A new Section III.13.1.2.3.1.A is being added to the Tariff to specify the numeric value of the Dynamic De-List Bid Threshold. If that value is changed in the future, it will no longer be necessary to update numerous sections of the Tariff; a single change to the new section will suffice.

Q: What principle should be used in setting the level of the Dynamic De-List Bid Threshold?

A: The Dynamic De-List Bid threshold should be set at the level of a competitive offer into the FCM. If a resource bids competitively, there is no need for the IMM to review its offer. However, if a resource bids above competitive levels, it may be attempting to exercise market power and its de-list bid should be reviewed. The current level of $1.00/kW-month is an estimate of the cost of taking on a Capacity Supply Obligation in the current market based on prices from annual reconfiguration auctions. Since it is an estimate of the cost of taking on an obligation, it represents a competitive offer.

Q: Will the Dynamic De-List Bid Threshold change under Pay For Performance?

A: Yes. Beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018), the Dynamic De-List Bid Threshold shall be $3.94/kW-month.

Q: Why is the Dynamic De-List Bid Threshold being raised?

A: The Dynamic De-List Bid Threshold is being raised because the Pay For Performance design changes the definition of the capacity product and therefore changes the level of a competitive offer in the capacity market for all resources. Ideally, the IMM would set the Dynamic De-List Bid Threshold at the competitive bid of the marginal unit. By doing this, the IMM would only review non-competitive bids that could have material impact on the market outcomes. However, since it is obviously not possible to know the marginal unit prior to the auction, the IMM used values representative of fossil steam units to set the Dynamic De-List Bid Threshold because these are the type of existing resources most likely to seek to leave the auction and therefore could be the marginal unit if there is more existing capacity than needed to meet the Installed Capacity Requirement.

Q: How did you calculate the Dynamic De-List Bid Threshold based on the representative characteristics of fossil steam units?

A: We used the same approach described above in the section on expected Capacity Performance Payments. We describe it more formally here using equations to derive the optimal bid or offer into the FCM under Pay For Performance.

The optimal bid for a profit-maximizing proxy unit (i) under Pay For Performance is described by the following formula:

$$b_i = PPR \times Br \times H + \max\{0,\ GFC_i - PPR \times A_i \times H\}$$

Where:

- *PPR* is the Capacity Performance Payment Rate specified in the Tariff.
- *Br* is the expected Capacity Balancing Ratio.
- *H* is the expected number of hours with Capacity Scarcity Conditions during the commitment period.
- *GFC* is the resource's net going-forward cost.
- *A* is the expected average performance of the resource during Capacity Scarcity Conditions during the commitment period.

In the formula above, the Capacity Performance Payment Rate, Capacity Balancing Ratio, and the expected number of hours with Capacity Scarcity Conditions during the commitment period are system characteristics and are not resource dependent. Except for the Capacity Performance Payment Rate, which is set by the Tariff, the IMM used historical values and expectations of future system conditions to establish the values for these variables to be used in setting the Dynamic De-List Bid Threshold.

The resource's net going-forward cost and the expected average performance of the resource during hours with Capacity Scarcity Condition during the commitment period clearly depend on the characteristics of the resource. The IMM used estimates of those characteristics for existing fossil steam resources in setting the Dynamic De-List Bid Threshold.

Q: Please explain the components of this formula and why it represents the competitive bid for such a resource?

A: The first portion of the equation ($PPR \times Br \times H$) represents the opportunity costs of assuming a Capacity Supply Obligation in the Forward Capacity Auction. These values are not resource-specific. The Capacity Payment Performance Rate (*PPR*) is a design parameter, and the Capacity Balancing Ratio (*Br*) and the number of hours with Capacity Scarcity Condition (*H*) are based on expected system conditions. *(PPR × Br × H)* is also termed the common value component of a resource's capacity market offer because it is common to all resources. The common value component is the lowest competitive bid and hence the Dynamic De-List Bid Threshold should be no lower than that.

The second portion of the equation ($\max\{0,\ GFC_i - PPR \times A_i \times H\}$) is a resource-specific value that represents the portion of the resource's going forward costs that is not covered by its expected Capacity Performance Payments (absent a Capacity Supply Obligation). The term ($PPR \times A \times H$) , that is, the Capacity Performance Payment Rate multiplied by the resource's average performance multiplied by the number of hours with Capacity Scarcity Conditions, determines the value of the resource's expected Capacity Performance Payments (absent a Capacity Supply Obligation). For resources submitting de-list bids, average performance is the reserve-shortage-duration weighted average of delivered energy and reserve divided by the unit's Capacity Supply Obligation.

If the expected Capacity Performance Payments are higher than the resource's net going-forward costs, then all of the resource's expected net going-forward cost is covered by its expected Capacity Performance Payments which all resources, irrespective of their Capacity Supply Obligation, receive. In this case, the resource would not need any Capacity Base Payments and would be active in the energy market even without having any FCM obligation, and the second portion of the equation will be zero.

If the Capacity Performance Payments (absent a Capacity Supply Obligation) are lower than the resource's going forward costs (GFC), the resource is unable to cover all of its net going-forward cost with its expected Capacity Performance Payments. In this case, the second portion of the equation will yield a positive value and this amount is added to the first portion of the equation. This means that that the resource will not clear in the capacity market unless the price is high enough to cover the sum of its opportunity cost of assuming a Capacity Supply Obligation *(PPR × Br × H)* and the portion of its net going-forward costs that is not covered by Capacity Performance Payments, if any ($\max\{0,\ GFC_i - PPR \times A_i \times H\}$). Together, these values represent the competitive bid for a profit-maximizing unit under Pay For Performance.

Q: What value is the IMM using for the Capacity Payment Performance Rate in applying the formula to calculate the Dynamic De-List Bid Threshold?

A: For the Capacity Performance Payment Rate (PPR), we use the rate specified in the Tariff under Pay For Performance. New Section III.13.7.2.5 states that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2,000/MWh.

Q: What value is the IMM using for the Capacity Balancing Ratio in the formula?

A: For the Capacity Balancing Ratio (*Br*), which is generally described as the sum of load and reserve requirement divided by the total quantity of Capacity Supply Obligations, the IMM used the historical value of 0.75, for the most recent complete years for which the ISO has collected data (2010-2012).

Q: **What value is the IMM using for the average number of hours with Capacity Scarcity Conditions in the formula?**

A: For the average number of Capacity Scarcity Condition hours (*H*), the IMM used 20.4 hours per year. The number of reserve deficiency hours depends on the amount of total MW available in the system. In modeling the amount of MW available on the system, the amount of surplus capacity increases as the Capacity Performance Payment Rate increases. At a *permanent* Capacity Performance Payment Rate of $2,000/MWh, the report entitled "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives" by Analysis Group Inc. dated September 2013 and provided in Attachment I-1g of this filing ("Impact Assessment") predicts that the system will have excess

capacity of 298 MW. This is the value that is used by the IMM to develop its estimates of the number of reserve deficiency hours.

Using the planning models that are regularly used to develop the Installed Capacity Requirement and are approved by the Commission, the ISO calculated the distribution of the reserve deficiency hours based on a system with 298 MW of surplus. In calculating the Dynamic De-List Bid Threshold the IMM used the 75th percentile of the distribution of reserve deficiency hours from that calculation which is equal to 20.4 hours per year.

Q: What value is the IMM using for the net going-forward cost in the formula?

A: The net going-forward cost used in setting the Dynamic De-List Bid Threshold was calculated using the de-list submissions made by fossil steam units for the eighth Forward Capacity Auction reviewed by the IMM in summer 2013. This is an excellent source for this data since nearly all of the region's fossil steam units submitted de-list bids. Unadjusted for inflation, the weighted average net going-forward costs of these units was $2.41/kW-month. Using the expected inflation figures published by the Federal Reserve Bank of Cleveland in December 2013, after adjusting for inflation, the weighted average net going-forward cost of these units is $2.56/kW-month. To reduce the likelihood of reviewing competitive offers, the IMM used $2.75 as the net-going forward cost establishing the Dynamic De-List Bid Threshold.

Q: What value is the IMM using for the average performance during reserve deficiency hours in the formula?

A: The value of average performance is based on the Impact Assessment. The Analysis Group analyzed resources in New England and their estimate of the weighted average performance of economic and non-economic oil units under Pay For Performance when the Capacity Performance Payment Rate is $2,000/MWh is 0.48. The IMM decided to use 0.4 for the average performance in the formula because the IMM finds this value consistent with the characteristics of the existing fossil steam fleet in New England. Choosing 0.4 rather than 0.48 will have the effect of slightly increasing the Dynamic De-List Bid Threshold and avoids unnecessary review of competitive de-list bids by the IMM.

Q: Will the Dynamic De-List Bid Threshold change over time?

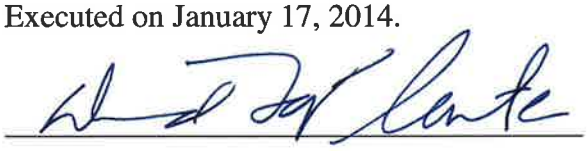
A: As stated in the revised rules, the Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the IMM will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

Q: Does this conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.



David LaPlante

Vice President, Market Monitoring

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

Executed on January 17, 2014.

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Economist

Attachment I-1f

Testimony of Marc Montalvo on behalf of the ISO

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-_____-000**
New England Power Pool	**)**	

TESTIMONY OF MARC D. MONTALVO
ON BEHALF OF ISO NEW ENGLAND INC.

Q: Please state your name, position, and business address.

A: My name is Marc D. Montalvo. I am Director of Enterprise Risk Management 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 am Director of Enterprise Risk Management at the ISO. Previously, I served as Director of Assessment and Investigation for Internal Market Monitoring as well as Director of Market Development. I have energy industry experience that includes risk management, finance, market surveillance, and power market design. I have testified before the Federal Energy Regulatory Commission ("FERC" or "Commission") in support of the ISO's market design proposals and have testified before state regulatory agencies on issues including resource economics, portfolio design, and asset valuation. Prior to joining the ISO in 2004, I served as Manager of Wholesale Market Analytics at La Capra Associates, an energy industry consultancy based in Boston, MA. Before joining La Capra Associates, I was an Analyst in the generation operations and marketing group at

New England Power Company (NEES). I hold a M.S. in Finance from Clark University and a B.S. in Mathematics from Allegheny College.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to explain revisions to the ISO's Financial Assurance Policy ("FAP") made necessary by the implementation of the Pay For Performance design in the Forward Capacity Market ("FCM").[1]

Q: Why does the FAP need to be revised to accommodate Pay For Performance?

A: Market obligations are collateralized through the posting of financial assurance ("FA") under the FAP. The goal of the FAP is to ensure that there is sufficient cash available to clear the market each day and to cover a participant's settled obligations in the case of default. FA requirements are established to cover extreme loss scenarios, generally at the 99 percent not to exceed level.

To date, FA related to participation in the FCM has been limited to new resources that are not yet commercial. For a resource that is operating commercially, taking on a Capacity Supply Obligation in the FCM currently does not result in any additional financial obligations. Capacity payments during a Capacity

[1] Capitalized terms used but not otherwise defined in this testimony 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, or the Pay For Performance rules.

Commitment Period under the current FCM design cannot be negative, and hence, for commercial resources, there has been no potential financial obligation to collateralize. As described in detail in the ISO's transmittal letter and in the testimony of ISO witness Matthew White, however, under Pay For Performance, a resource's net capacity payments may be negative.[2] In this way, Pay For Performance introduces the possibility that commercial resources with Capacity Supply Obligations will have net payment obligations (*i.e.*, owe money) to the market. Market participants must post collateral against such exposures under the FAP.

Q: Please summarize the general approach to the proposed changes to the FAP.

A: To collateralize this additional potential obligation, a Market Participant with a Capacity Supply Obligation will be required to add *Forward Capacity Market Delivery Financial Assurance* ("FCM Delivery FA") to its total FA requirements calculation. FCM Delivery FA is designed to address three types of risk: (1) clearing risk, (2) credit risk, and (3) liquidation risk. Clearing risk is the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month, which could result in a cash imbalance that impairs the ability of the ISO to clear all market positions. Credit risk is the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with Capacity Supply

[2] Testimony of Matthew White on behalf of the ISO, submitted with this filing as Attachment I-1c at 77.

Obligations in the current delivery month. Liquidation risk in this context has two components: the risk that losses may continue to accrue against a Capacity Supply Obligation position post default up to the annual stop-loss in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. In addition to addressing these three types of risk, the FCM Delivery FA amount is adjusted to account for the phase-in of the Capacity Performance Payment Rate.

Q: Specifically, how will the FCM Delivery FA amount be calculated?

A: The monthly FCM Delivery FA requirement will be calculated using the following formula: FCM Delivery FA =

$$MCC + DFAMW \times PE \times \max[(ABR - CWAP), 0.1)] \times SF \times DF$$

I will explain each element of this formula in detail below.

I. CLEARING RISK

Q: How does the FCM Delivery FA formula address clearing risk?

A: The first of the three risks that I mentioned is clearing risk – the risk that a Market Participant does not timely discharge settled payment obligations incurred in an already completed delivery month. The first component of the FCM Delivery FA formula, MCC or "monthly capacity charge," addresses clearing risk. The monthly capacity charge is an amount equal to all negative capacity payments incurred in previous months, but not yet paid. This value will be estimated on the

first business day following a completed delivery month, and will be replaced with the actual settled value when settlement is complete. A similar approach is applied to all market charges under the FAP – the required FA reflects charges settled but not invoiced and charges invoiced but not paid. By requiring the posting of the monthly capacity charge, if the Market Participant fails to pay its invoice on time, the ISO can still meet its obligations to all other cleared positions by drawing against the Market Participant's posted collateral. Requiring the collateral to be posted on the first business day following the completion of the delivery month maximizes the potential offset against any incurred negative capacity payments in that month. Failure to post the required FA results in suspension from the markets, limiting the extent to which the Market Participant can accumulate additional market obligations.

II. CREDIT RISK

Q: How does the FCM Delivery FA formula address credit risk?

A: The second of the three risks that I mentioned is credit risk – the risk that a Market Participant will default on payment obligations arising from negative capacity payments associated with Capacity Supply Obligations in the current delivery month. This risk is addressed in the portion of the FCM Delivery FA formula that states: DFAMW x PE x max[(ABR – CWAP), 0.1)]. At a high level, the "DFAMW" term represents the MW amount on which a Market Participant must submit FCM Delivery FA; "PE" is the dollar per MW value that will apply

in calculating the Market Participant's FCM Delivery FA; and "max[(ABR – CWAP), 0.1]" is a ratio reflecting the performance of the Market Participant's capacity resources.

Q: Please explain the credit risk term "DFAMW" in more detail.

A: DFAMW, or "delivery financial assurance MW," is, simply, the total MW amount of a Market Participant's resources subject to a Capacity Supply Obligation in the current month. This MW amount serves as the basis for the credit risk portion of the FCM Delivery FA calculation. The DFAMW is equal to the sum of the Capacity Supply Obligations of all resources in the Market Participant's portfolio for the current month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount. In no case will DFAMW be less than zero.

Q: Why is the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount excluded from the DFAMW calculation?

A: The annual stop-loss limits the amount of money a resource with a Capacity Supply Obligation can lose during a Capacity Commitment Period to three times its monthly stop-loss amount. A resource that has reached the annual stop-loss amount cannot incur any further negative capacity payments in the current month, so no additional amount of FA associated with that resource is needed to protect against default. For this reason, it is excluded from the calculation. However, should the resource receive performance payments in any subsequent month, the

resource's Capacity Supply Obligation will again be included in the FCM Delivery FA calculation.

Q: Why can DFAMW not be less than zero?

A: The purpose of FCM Delivery FA is to require collateral for potential payment obligations (negative capacity payments) under Pay For Performance. If there are no potential payment obligations, FCM Delivery FA should be zero. In no case, however, would it be appropriate for the FCM Delivery FA amount to be negative, possibly offsetting other, independent FA requirements. To prevent this, the DFAMW may not be negative.

Q: Please explain the credit risk term "PE" in more detail.

A: PE, or "potential exposure," is the dollar per MW value that will apply in calculating the Market Participant's FCM Delivery FA. Conceptually, this value is the maximum monthly payment a Market Participant would be required to make. As such, for a given delivery month, this value forms the upper bound on credit default exposure.

PE is calculated monthly for the Market Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount. The difference between

the Forward Capacity Starting Price and the capacity price is used because, as a general matter, this is equivalent to how the stop-loss amounts are calculated under Pay For Performance, and so represent the amount per MW that the Market Participant might be required to pay if its resources fail to perform.

For the purpose of calculating PE, the Forward Capacity Auction Starting Price shall be the one used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period, and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month. The reference to capacity prices in the Capacity Base Payment calculation is for simplicity, as capacity prices vary depending on whether the Capacity Supply Obligation was assumed in a Forward Capacity Auction, a reconfiguration auction, or a bilateral transaction. The Capacity Base Payment provisions in Section III.13.7.1 of the Pay For Performance rules detail which prices apply. The use of a capacity weighted average price ensures that the price per MW value properly corresponds to the capacity that is part of the DFAMW. Also, the PE calculation excludes the Capacity Supply Obligation of any resource that has reached the annual stop-loss amount, similarly ensuring that the price per MW value properly corresponds to the capacity that is part of the DFAMW.

Finally, the PE calculation recognizes that resources that cleared before the ninth Forward Capacity Auction and elected to have the clearing price apply for more

than one Capacity Commitment Period are subject to a special monthly stop-loss provision. For such resources, the Forward Capacity Auction Starting Price in the PE calculation shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) until the multi-year election period expires. This ensures that the PE properly reflects the monthly stop-loss values to which the resources in a portfolio that includes such resources are exposed.

Q: Please explain the credit risk term "max[(ABR – CWAP), 0.1]" in more detail.

A: "max[(ABR – CWAP), 0.1]" is a ratio reflecting the performance of the Market Participant's capacity resources. Under Pay For Performance, a resource is not held to the standard of providing the full amount of its Capacity Supply Obligation in all cases. Rather, the amount of capacity that a resource provides during a Capacity Scarcity Condition is measured against the ratio of the total amount of load plus the reserve requirement, divided by the total amount of Capacity Supply Obligations. This ratio is called the Capacity Balancing Ratio. As an example, if the total load plus reserve requirement is only 60 percent of the total amount of Capacity Supply Obligations (for a Capacity Balancing Ratio of 0.6), a resource with a 100 MW Capacity Supply Obligation would be over-performing if its actual capacity provided during a Capacity Scarcity Condition is greater than 60 MW, and under-performing if its actual capacity provided is less than 60 MW.

Because capacity payments are linked to the Capacity Balancing Ratio, FCM Delivery FA must be as well. Requiring a Market Participant to provide FA based on the full amount of its Capacity Supply Obligations would over-state the amount needed to protect against default because negative capacity payments will only be tied to the full Capacity Supply Obligation amount when the Capacity Balancing Ratio is 1.0 – that is, when the system is so stressed that the amount of load plus reserves is equal to the total amount of Capacity Supply Obligations. The term "max[(ABR – CWAP), 0.1]" is the minimum percentage of the calculated potential exposure (PE) that must be posted as FA given assumptions regarding the average system-wide Capacity Balancing Ratio and on the performance of the Market Participant's capacity resources.

Q: Please explain the term "ABR" as used in this credit risk term.

A: ABR, or "average balancing ratio," is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

For example, assume that in summer 1, there are 2.5 hours of Capacity Scarcity Conditions during which the average system-wide Capacity Balancing Ratio was 0.90; in summer 2, there are 3.0 hours of Capacity Scarcity Conditions during

which the average system-wide Capacity Balancing Ratio was 0.95; and in summer 3, there are 2.0 hours of Capacity Scarcity Conditions during which the average system-wide Capacity Balancing Ratio was 0.93. The average balancing ratio calculated over the three historical summer periods would be:

(2.5 x 0.90) + (3.0 x 0.95) + (2.0 x 0.93) / (2.5 + 3.0 + 2.0) = 6.96 / 7.5 = 0.93.

Q: Why are you using a different ABR for different groups of months?

A: This design component simply reflects the observation that the average system-wide Capacity Balancing Ratio is likely to be highest in the summer (June through September), lower (but still relatively high) in the winter (December through February), and lowest in the remaining months of the year.

Q: Because there will be no Capacity Scarcity Conditions until the ninth Capacity Commitment Period, how will ABR be determined before there is sufficient data?

A: Until data exists to calculate ABR, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

In other words, if there is only one year of actual data, that actual data will receive a weight of 1/3 in the calculation, and the remaining two years will be based on the temporary value. If there are two years of actual data, that actual data will receive a weight of 2/3 in the calculation, and the remaining one year will be based on the temporary value. For example, assume one year of actual performance data in which the average system-wide Capacity Balancing Ratio for June through September equals 0.92. The ABR for the June through September period would be: [(0.92) x 1/3] + [0.90 x 1/3] + [0.90 x 1/3] = 0.91.

Q: How did you determine these temporary ABR values?

A: The temporary ABR values are estimates determined by applying the criteria for Capacity Scarcity Conditions under Pay For Performance to actual operating data from 2010 through 2013, and then averaging by season the system-wide Capacity Balancing Ratios calculated according to the method described in the Pay For Performance rules.

Q: Please explain the term "CWAP" as used in the credit risk term "max[(ABR – CWAP), 0.1]."

A: CWAP, or "capacity weighted average performance," is the capacity weighted average performance of the Market Participant's portfolio. As I stated above, the term "max[(ABR – CWAP), 0.1]" is the minimum percentage of the calculated potential exposure (PE) that must be posted as FA given assumptions regarding the average system-wide Capacity Balancing Ratio and on the performance of the

Market Participant's capacity resources. Generally, the better a Market Participant's resources have performed, the higher its CWAP value will be, and the lower the value (ABR – CWAP) becomes. The worse a Market Participant's resources have performed, the lower its CWAP value will be, and the higher the value (ABR – CWAP) becomes. The higher the value (ABR – CWAP), the more FA the Market Participant must post for its portfolio.

Conceptually, CWAP is simply the amount of capacity provided divided by the amount of capacity obligated. Specifically, for each resource in the Market Participant's portfolio, excluding any resource that has reached the annual stop-loss amount, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Market Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

For example, assume a portfolio with three resources, each with an average performance value of 0.85, with the following Capacity Supply Obligations: 110 MW, 100 MW, and 90 MW. None of the resources has reached the annual stop-loss amount. In this simple case, the Market Participant's CWAP would be: [(110 x 0) + (100 x 0.85) + (90 x 0.85)] / 300 = 0.54. The 110 MW resource is the largest in the portfolio, and so in this example is multiplied by zero to exclude its performance.

Q: Why does the CWAP calculation exclude the largest resource remaining in the Market Participant's portfolio after resources that have reached the annual stop-loss have been excluded?

A: A portfolio with multiple resources provides some diversification benefits, with negative performance payments to one resource offset by positive payments to another. As a general matter, the portfolio is exposed to the greatest loss when the largest resource fails to perform. The failure of the largest resource also serves as a reasonable proxy for below-average performance by other resources in the portfolio. Assuming that all resources in a portfolio fail to perform, or perform substantially below average, would overestimate the degree to which any portfolio of resources actually faces negative performance payments. Given the composition of resource portfolios in New England, assuming that the largest resource in a multiple resource portfolio does not perform but that the balance of the portfolio performs as expected during shortage conditions provides a reasonable protection against Market Participant default under extreme loss scenarios.

Q: How will each resource's average performance be calculated for purposes of the CWAP determination?

A: The average performance of a resource is the cumulative amount of Actual Capacity Provided (as defined in the Pay For Performance rules) during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the

relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months.

For example, assume a resource with a 100 MW Capacity Supply Obligation. In summer 1, there are 2 hours of Capacity Scarcity Conditions during which the resource delivered a cumulative 200 MWh of energy and reserves; in summer 2, there are 3 hours of Capacity Scarcity Conditions during which the resource delivered a cumulative 250 MWh of energy and reserves; and in summer 3, there are 2 hours of Capacity Scarcity Conditions during which the resource delivered a cumulative 150 MWh of energy and reserves. The average performance of this resource calculated over the three historical summer periods would be:
(200 + 250 + 150) / (100 x (2 + 3 + 2)) = 600 / 700 = 0.86.

Q: Because there will be no Capacity Scarcity Conditions until the ninth Capacity Commitment Period, how will average performance be determined before there is sufficient data?

A: Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines, and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall

equal 0.65; and the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

In other words, if there is only one year of actual data, that actual data will receive a weight of 1/3 in the calculation, and the remaining two years will be based on the temporary value. If there are two years of actual data, that actual data will receive a weight of 2/3 in the calculation, and the remaining one year will be based on the temporary value. For example, again assume a resource with a 100 MW Capacity Supply Obligation, but only one year of actual performance data. There are 2.5 hours of Capacity Scarcity Conditions in that year, during which the resource delivered a cumulative 200 MWh of energy and reserves. The resource is a coal-fired steam plant, so as described above receives a temporary average performance value of 0.85. The average performance of this resource would be: [(200 / (100 x 2.5)) x 1/3] + [0.85 x 1/3] + [0.85 x 1/3] = 0.83.

Q: How did you determine these temporary average performance values?

A: The temporary average performance values are based on data contained in the report entitled "Assessment of the Impact of ISO-NE's Proposed Forward

Capacity Market Performance Incentives" by Analysis Group Inc. dated September 2013 and provided in Attachment I-1g of this filing. Specifically, see Table 6: "Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario" on page 38 of that report. The values from the report have been and rounded to the nearest five percent value and capped at 100 percent. For example, 86 percent is rounded to 0.85, and 105 percent is capped to 1.0.

Q: Please explain the role of the maximization function in the credit risk term "max[(ABR – CWAP), 0.1]."

A: As I explained above, generally, the better a Market Participant's resources perform, the higher its CWAP value will be, and the lower the value (ABR – CWAP) becomes. The worse a Market Participant's resources perform, the lower its CWAP value will be, and the higher the value (ABR – CWAP) becomes. For a resource with a CWAP value that approaches or exceeds ABR, the value (ABR – CWAP) will become very low, or possibly even negative. If this value reached zero, the credit risk portion of the FCM Delivery FA would also become zero. Although this would occur because the Market Participant's resources were performing well, even those portfolios with a CWAP value higher than the ABR are not completely without risk. The ABR and the CWAP are based on historical data, and if future performance is worse, holding some FA associated with credit risk is a reasonable and prudent protection.

For this reason, the maximization function included in the term "max[(ABR – CWAP), 0.1]" ensures that the value of that term will not be below 0.10, and hence, at least ten percent of the potential exposure amount will be included in the FCM Delivery FA amount.

III. LIQUIDATION RISK

Q: How does the FCM Delivery FA formula address liquidation risk?

A: The third of the three risks that I mentioned is liquidation risk – the risk that losses may continue to accrue against a Capacity Supply Obligation position post default up to the annual stop-loss in any Capacity Commitment Period before a Market Participant is able to close the position, and the risk that the defaulted position, when closed, is sold at a loss. Recall that the monthly FCM Delivery FA requirement will be calculated using the following formula: FCM Delivery FA =

$$MCC + DFAMW \times PE \times \max[(ABR - CWAP), 0.1)] \times SF \times DF.$$

Liquidation risk is addressed in the "SF," or "scaling factor," term included in the formula. The scaling factor is a month-specific multiplier, as follows:

- June: 2.000;
- December and July: 1.732;
- January and August: 1.414;
- all other months: 1.000.

Q: Please explain the liquidation risk "scaling factor" in more detail.

A: The risk that losses may continue to accrue against a Capacity Supply Obligation position post default (up to the annual stop-loss) before a Market Participant is able to close the position is not uniform across all months of the Capacity Commitment Period. The likelihood of a severe scarcity event is different each month of the year. Review of historical data (2010-2013) shows that the risk of scarcity conditions varies by season. The risk of scarcity is highest in the summer months (June – September), followed by the winter months (December – February) and lowest in the shoulder months (the other months).

Furthermore, given that in the summer and winter there are consecutive high-risk months in a row, should a resource default early in the summer season, for example, there is the risk that it will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions. In large measure this risk exists because a defaulted Capacity Supply Obligation position is not terminated from the market. Rather, the Market Participant must close the position through a bilateral contract or continue to be exposed to charges up to the annual stop-loss.

While the maximum possible exposure is the annual stop-loss, the probability that a resource will hit the monthly stop-loss three months in a row (the annual stop-loss equals three times the monthly stop-loss) is low. Thus, requiring Market Participants to post FA up to the annual stop-loss would unnecessarily over-

collateralize the market. Nonetheless, additional FA is required to address the risk that a defaulted position will accrue additional losses in subsequent months due to the higher potential for additional Capacity Scarcity Conditions in the summer and winter seasons when Capacity Scarcity Conditions are likely to be more frequent. For this purpose, we have assumed that the potential exposure in any remaining months of a season is normally distributed and that the exposure to incremental losses declines with the square-root of the number of months remaining in the season. Thus, during high risk months (summer and winter), the scaling factor (SF) is calculated as the square root of the number of summer or winter months remaining in the seasonal period. For example, the SF is two (square root of four) in June, and becomes one (square root of one) in September. During all the shoulder months, the scaling factor is one.

To see why the square root of the number of months remaining in the season is used as the scaling factor in the formula, consider the following. First, the potential exposure (PE), which captures the potential losses under extreme conditions in one month (*e.g.*, the first percentile value for a given distribution of risky cash flows), is measured by a multiple of the standard deviation of the underlying random variable. If we model the risky cash flows to a one MW Capacity Supply Obligation in each month of the same season with an identical independent random variable with a finite standard deviation, then the total risky cash flows for the season will be the sum of the risky cash flows assigned to each of these random variables. According to a basic property of variance (square of

standard deviation) of a random variable, the variance of the sum of independent variables equals the sum of the variance of the random variables. If we apply this property to the problem at hand, the variance of the risky cash flows for a season will equal the variance of the risky cash flows for the month times the number of months remaining in the season. By taking the square root of both sides of the equation above, we find that the standard deviation (square root of variance) of the risky cash flows for a one MW Capacity Supply Obligation for the season equals the standard deviation of the risky cash flows for the one MW Capacity Supply Obligation in the month times the square root of the months remaining in the season. Hence, the square root of the months remaining in the season is the scaling factor applied to the potential exposure component of the FCM Delivery FA calculation.

The practical effect of this scaling factor adjustment is that the Market Participant may be required to post FCM Delivery FA that exceeds the monthly stop-loss in months that come at the beginning of seasons where there is a higher risk of Capacity Scarcity Conditions. To reflect the annual cap on overall losses against a Capacity Supply Obligation, once a resource hits its annual stop-loss it is excluded from the FCM Delivery FA calculation.

IV. ADJUSTMENT TO FCM DELIVERY FA TO ACCOUNT FOR THE PHASING-IN OF THE CAPACITY PERFORMANCE PAYMENT RATE

Q: You stated above that in addition to addressing the three types of risk, the FCM Delivery FA amount is adjusted to account for the phase-in of the Capacity Performance Payment Rate. Please explain.

A: The only term in the FCM Delivery FA formula that I have yet to explain is the term "DF," or "discount factor." The discount factor is a multiplier to the credit risk portion of the FCM Delivery FA amount. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the discount factor equals 0.75, and thereafter, equals 1.00.

Under the Pay For Performance design, the Capacity Performance Payment Rate is being phased in. For the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, the Capacity Performance Payment Rate shall be $2000/MWh. For the three Capacity Commitment Periods beginning June 1, 2021 and ending May 31, 2024, the Capacity Performance Payment Rate shall be $3500/MWh. For the Capacity Commitment Period beginning on June 1, 2024 and ending on May 31, 2025 and thereafter, the Capacity Performance Payment Rate shall be $5455/MWh.

The discount factor was added to the FCM Delivery FA calculation to reflect the reduced exposure to losses during the years in which the Capacity Performance Payment Rate is being phased in. The discount factor is based on the likelihood of a single resource portfolio reaching its monthly stop-loss under different Capacity Performance Payment Rates. For a single resource portfolio, a lower

Capacity Performance Payment Rate requires more hours of Capacity Scarcity Conditions to reach the monthly stop-loss amount.

Analysis performed by the ISO suggests an average number of Capacity Scarcity Condition hours on the order of six (expected value of 20 per year) to nine (95^{th} percentile value of 30 per year) per summer month. At a Capacity Performance Payment Rate of $5,455/MWh and assuming an annual average system-wide Capacity Balancing Ratio of 0.75, it would take three to four hours of Capacity Scarcity Conditions to reach the $15,000/MW-month monthly stop-loss amount; less than the expected number of hours of Capacity Scarcity Conditions. At a Capacity Performance Payment Rate of $3,500/MWh and assuming an annual average system-wide Capacity Balancing Ratio of 0.75, it would take five to six hours of Capacity Scarcity Conditions to reach the $15,000/MW-month monthly stop-loss amount; similarly less than the expected number of hours of Capacity Scarcity Conditions. However, at a Capacity Performance Payment Rate of $2,000/MWh, and assuming an annual average system-wide Capacity Balancing Ratio of 0.75, it would take ten hours of Capacity Scarcity Conditions to reach the $15,000/MW-month monthly stop-loss amount. This value is greater than the 95^{th} percentile value.

Based on these calculations, there is no material difference in exposure associated with a Capacity Performance Payment Rate of $3,500/MWh versus $5,455/MWh, so the discount factor is set to one (*i.e.*, the credit risk portion of the FCM Delivery FA calculation is unchanged for those instances of the Capacity

Performance Payment Rate). However, with a Capacity Performance Payment Rate of $2,000/MWh, it does take many more hours of Capacity Scarcity Conditions to reach the monthly stop-loss amount.

Based on the data above, for a Capacity Performance Payment Rate of $2,000/MWh the PE is 60 to 90 percent of the value at a Capacity Performance Payment Rate of $5,455/MWh. However, given the uncertainly in the data and the imprecision of the calculation, we have opted to split the difference and set the PE when the Capacity Performance Payment Rate is $2,000/MWh at 75 percent of its full value. Thus, for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF equals 0.75; and thereafter, DF equals 1.00.

V. OTHER CONFORMING REVISIONS

Q: Are there any other changes being made to the FAP as part of the Pay For Performance changes?

A: All of the changes to the FAP that I discussed above are contained in Section VII.A of the FAP, which details the new FCM Delivery FA. Several conforming revisions to the balance of Section VII are also required to accommodate that change. Because Section VII previously only discussed FA related to non-commercial capacity, it was referred to generically. Because the new revisions

add FA for commercial capacity resources, the previously-existing references are being revised to clarify they apply specifically to "non-commercial" capacity.

Furthermore, the revisions include some minor conforming changes to the treatment of composite resources. Part 2 of Section VII.E of the FAP is being deleted because under the revised rules, the FCM Delivery FA will automatically be set to zero when a Capacity Supply Obligation goes to zero and all outstanding payment obligations are discharged. A new part 6 of Section VII.E is being added to address the case when one component of a composite transaction incurs net charges. This provision clarifies that the payment obligation remains with the Market Participant responsible for that component of the composite transaction.

Finally, Section VII.F.3 is being deleted because it no longer applies. Under the current FCM rules, under certain conditions, expected future FCM revenues could offset FA requirements. However, under the revised Pay For Performance rules, all potential FCM payments are used in the FCM Delivery FA calculation to reduce negative performance payment exposure.

Q: Does this conclude your testimony?

A: Yes.

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

Executed on January 17, 2014.

Marc Montalvo

Director – Enterprise Risk Management

Attachment I-1g

Affidavit of Todd Schatzki on behalf of the ISO and Impact Assessment by Analysis Group, Inc.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___-000**
New England Power Pool	**)**	

AFFIDAVIT OF TODD SCHATZKI
ON BEHALF OF ISO NEW ENGLAND INC.

My name is Todd Schatzki, and I am a Vice President at Analysis Group Inc. ("Analysis Group"). I am submitting this affidavit in support of the proposal by ISO New England ("ISO-NE") to modify the Forward Capacity Market ("FCM") to include a Pay For Performance (also known as Performance Incentives) mechanism that would increase the current incentives for resource performance and investment by providing additional revenues to resources that supply power (or reduce demand) during periods of the greatest system need.

In my position with Analysis Group, I apply microeconomics, econometrics, and data analysis to complex business and regulatory problems, particularly in the areas of energy and environmental economics and regulation. Prior to joining Analysis Group, I held positions at LECG, LLC and National Economic Research Associates, Inc., where I performed similar types of economic analysis. I earned a Ph.D. in Public Policy from Harvard University, an M.C.P. from the Massachusetts Institute of Technology in Environmental Policy and Planning, and a B.A. from Wesleyan University in Physics. A complete list of my qualifications, publications, reports, and prior experience is set forth in Attachment A to my affidavit.

In March 2013, ISO-NE retained Analysis Group to assess the impact of ISO-NE's proposed FCM Pay For Performance market rule changes. The Analysis Group's impact assessment is set forth in a report entitled "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives" (the "Impact Assessment"). A copy of that report is provided as Attachment B to my affidavit.

I hereby certify that the Impact Assessment was prepared under my direction and supervision and that the facts set forth therein are true to the best of my knowledge, information, and belief.

Todd Schatzki

Subscribed and sworn to before me
this 14th day of January 2014

Notary Public

My commission expires: 11/3/2017

DENISE VAN VOOREN
Notary Public
Massachusetts
Commission Expires Nov 3, 2017

Attachment A

Resume of Dr. Todd Schatzki

TODD SCHATZKI, Ph.D.
VICE PRESIDENT
ANALYSIS GROUP INC.

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Dr. Schatzki is an expert in energy and environmental economics and policy, and specializes in the application of microeconomics, econometrics, and data analysis to complex business and policy problems. He has worked with clients on corporate strategy, public policy design, and problems arising in regulation and litigation.

Dr. Schatzki has worked extensively on the design of electricity markets, analysis of wholesale electricity markets, economic analysis of energy and environmental regulations, asset valuation, resource planning and procurement, and utility ratemaking. His research has been supported by organizations such as the Electric Power Research Institute, Edison Electric Institute, Federal Energy Regulatory Commission, and National Association of Regulatory Utility Commissioners. His work has appeared in journals such as the *Journal of Environmental Economics and Management*, *the Electricity Journal*, *Public Utilities Fortnightly*, and *AEI-Brooking Joint Center for Regulatory Studies.* He has provided litigation support in many cases, including several high profile cases involving alleged wholesale electricity price manipulation and the implications of such manipulation for derivative contracts.

Prior to joining Analysis Group, he had research and consulting affiliations with the Harvard Institute for International Development and the International Institute for Applied Systems Analysis (Vienna, Austria), and was an economist at LECG, LLC and National Economic Research Associates.

EDUCATION

1998 Ph.D., Public Policy, Harvard University, Cambridge, MA

Specialized Fields: Microeconomics, econometrics, industrial organization, natural resource and environmental economics

- Doctoral Fellow, Harvard University, Cambridge, MA (1993-1995)
- Crump Fellowship, Harvard University, Cambridge, MA (1995-1996)
- Pre-doctoral Fellow, Harvard Environmental Economics Program

1993 M.C.P., Environmental Policy and Planning (Urban Studies and Planning,), M.I.T., Cambridge, MA

1986 B.A., Physics, Wesleyan University, Middletown, CT

PROFESSIONAL EXPERIENCE

2005-present	Analysis Group, Inc
2001-2005	LECG, LLC, *Managing Economist*
1998-2001	National Economic Research Associates, Inc., *Senior Consultant*
1997-1998	Harvard Institute for International Development, *Consultant*
1996-1997	Department of Economics, Harvard University, *Teaching Fellow and Research Assistant*
1994	International Institute for Applied Systems Analysis (IIASA)
1992	Toxics Reduction Institute, University of Massachusetts
1987-1991	Tellus Institute, *Research Associate*

SELECTED CASE WORK

Energy

- **ISO New England.** Assessment of the economic and reliability impacts of proposed capacity market rules introducing new performance incentives
- **Entergy.** Evaluation of economic damages associated with an alleged contract breach
- **ITC Midwest.** Analysis of the LMP and production cost impacts of new transmission infrastructure (using PROMOD)
- **Ameren.** Analysis of the impact of new transmission infrastructure on energy market competition in Illinois (using PROMOD)
- **Dayton Power and Light.** Evaluation of the aggregate benefits created by a proposed rate plan
- **Corporation with distribution companies across multiple jurisdictions.** Regulatory assessment considering current ratemaking models, regulatory environment and alternative ratemaking structures
- **ISO New England.** Assessment of the costs, feasibility and effectiveness of technical options to securing fuel supply for gas-fired generators
- **ISO New England.** Assessment of reliability risks and potential market and regulatory solutions to electric-gas interdependencies
- **Pacific Gas and Electric.** Assessment of ratemaking issues, including cost of capital adjustments, associated with a gas pipeline safety plan
- **ISO New England.** Statistical analysis of the performance of resources responding to system contingencies
- **Direct Energy.** Assistance developing regulatory options for promoting retail competition in Pennsylvania, including development of customer service auctions
- **ISO New England.** Assistance developing design enhancements for the region's Forward Reserve Markets
- **Confidential Client.** Analysis of energy and capacity market implications of a potential asset agreement (using GE's Multi-Area Production Simulation Software)

- **Confidential Client.** Analysis of fleet turnover decisions and outcomes (using GE's Multi-Area Production Simulation Software)
- **Confidential Regulated Utility.** Development of a white paper on transmission planning and policy needed to support legislative and regulatory goals for renewable development
- **Commonwealth Edison.** Analysis of appropriate ratemaking tools (cost of equity adjustment) in light of energy efficiency program requirements
- **New England Power Generators Association.** Analysis of impacts of proposed electric power company merger
- **Confidential Technology Company.** Development of a quantitative model of energy savings associated with end-use technological modifications..
- **Confidential Regulated Utility.** Development of a white paper assessing the potential for alternative ratemaking tools to mitigate multiple utility capital, load and service challenges
- **EDF Group.** Analysis of financial and credit implications of the sale of a portion of power generation assets
- **New England States Committee on Electricity.** Technical support and analysis related to design of regulations and wholesale electricity markets to achieve resource adequacy
- **National Grid Utilities.** Assistance developing ratemaking plans including revenue decoupling and associated revenue adjustments
- **NARUC and FERC.** Analysis of "best practices" in state policies for competitive procurement of retail electricity supply
- **New York ISO.** Analysis of single-clearing-price versus pay-as-bid market designs
- **Confidential System Operator.** Analysis of metrics for characterizing the economic value provided by regional transmission organizations
- **TransCanada.** Assessment of regulatory and finance issues involved in fuel adjustment clauses within long-term standard offer service contracts
- **New York ISO.** Analysis of market implications of fuel diversity issues
- **Confidential.** Analysis of alleged exercise and extension of market power in a wholesale electricity market, including statistical analysis of spot and real-time electricity markets and statistical modeling of outages using hazard model methods to examine potential physical withholding
- **Confidential.** Financial and strategic analysis of gas supply contracting alternatives
- **Confidential.** Analysis of value of generating assets using real options analysis
- **Confidential.** Statistical analysis of prices in the spot and forward markets using time-series methods for an energy trading firm in a federal proceeding related to the reasonableness of the terms of certain forward market contracts
- **Confidential.** Financial and strategic analysis of renewable generation technologies

Environment

- **Chevron.** Development of a white paper on post-2020 climate policy for California.
- **Greater Boston Real Estate Board.** Development of a white paper on mandatory building energy labeling/benchmarking policies

- **Chevron.** Analysis of the economic and environmental consequences of a local climate policy plan implemented in the context of a state-wide cap-and-trade system
- **Exelon.** Analysis of the economic and market consequences of EPA's Clean Air Transport Rule
- **Chevron.** Assessment of lessons learned from Federal requirements for regulatory review for the potential development of state requirements
- **Western States Petroleum Association and Chevron.** Regulatory support and analysis related to climate policy in California, including submission of various comments and reports to the Air Resources Board
- **Honeywell.** Analysis of proposed limits on HFC consumption under domestic climate policy
- **Electric Power Research Institute.** Analysis of three 2006 studies on the economic impact of meeting the California carbon emissions reduction targets (in the California Global Warming Solutions Act of 2006)
- **Confidential.** Assessment of various policy issues in the design of national climate change policies, including market-based policies, approaches to cost containment, offset projects, and non-CO_2 GHGs
- **Confidential.** Quantitative analysis of the impacts for technology, consumers and asset owners of a market-based domestic climate policy
- **Toyota.** Analysis of the economic value of emissions for a major auto manufacturer associated with alleged non-compliance with emissions control requirements

Finance and Commercial Damages

- Analysis of financial and credit implications of the sale of a portion of power generation assets
- Analysis of bond pricing, transactions and holdings related to default of sovereign bonds
- Analysis of transfers between financial institutions within credit card networks
- Analysis of the impact of product taxes on firm market shares related to determination of payments under a settlement agreement
- Analysis of damages related to breached contract and appropriation of trade secrets in the development of a pharmaceutical product
- Analysis of damages from breach of commodity swap contract (petroleum)
- Analysis of allegations regarding mutual fund day trading, including analysis of trading patterns and calculation of dilution

Antitrust

- Estimation of damages associated with an alleged monopolization and foreclosure resulting from a distribution agreement (retail consumer products)
- In a price-fixing case across multiple markets in the pharmaceutical industry, estimated overcharges and cartel periods based on a time-series analysis of price data
- Analysis of multiple antitrust claims (including foreclosure, monopolization, and vertical restraints) related to an alleged collusive distribution arrangement (retail consumer product)
- Analysis of alleged tying of aftermarket products and the provision of service, including evaluation of the alleged tie, competitive effects, and damages (office systems)
- Analysis of liability, timing, geographic scope, and damages issues for a petrochemical company facing potential price-fixing charges by DOJ and private parties

- Analysis of tying, monopolization, and patent abuse claims involving a patent licensing scheme for process and instrument patents (scientific equipment)
- Analysis of foreclosure, attempted monopolization of innovation markets, and damages claims arising from the termination of an investment/licensing agreement (medical devices)
- Estimation of damages related to alleged invalid patents and tying of products to patent rights associated with a process patent (scientific equipment)

ARTICLES AND PAPERS

"The Interdependence of Electricity and Natural Gas: Current Factors and Future Prospects," (with Paul Hibbard), *The Electricity Journal*, May 2012.

"California's Cap-and-Trade Decisions," Forbes.com, August 19, 2010.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," (with Susan F. Tierney), *The Electricity Journal*, March 2009.

"Pay-as-Bid vs. Uniform Pricing: Discriminatory Auctions Promote Strategic Bidding and Market Manipulation" (with Susan F. Tierney and Rana Mukerji), *Public Utilities Fortnightly*, March 2008.

"Free Greenhouse Gas Cuts: Too Good to Be True?" (with Judson Jaffe and Robert Stavins) VoxEU.org, January 3, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy" (with Robert N. Stavins and Judson Jaffe), AEI-Brookings Joint Center for Regulatory Studies, Related Publication 07-01. Jan 2007.

"Options, Uncertainty and Sunk Costs: An Empirical Analysis of Land Use," Journal of Environmental Economics and Management, Vol. 46, p. 86-105, 2003.

"The database on the economics and management of endangered species (DEMES)," (with David Cash, Andrew Metrick, and Martin Weitzman) in *Protecting Endangered Species in the United States: Biological Needs, Political Realities, Economic Choices*. Cambridge University Press, 2001

"The Issue of Climate," *Fundamentals of the Global Power Industry, Petroleum Economist, 2000.*

Review of "Sustainable Cities: Urbanization and the Environment in International Perspective," *Environmental Impact Assessment Review*, (Vol. 12, No, 4), 1993.

"Bottle Bills and Municipal Recycling," *Resource Recycling*, June 1991.

WORKING PAPERS

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," March 2012.

Schatzki, Todd, Paul Hibbard, Pavel Darling and Bentley Clinton, Generation Fleet Turnover in New England: Modeling Energy Market Impacts, June, 2011.

"A Hazard Rate Analysis of Mirant's Generating Plant Outages in California," with William Hogan and Scott Harvey. Presented at the IDEI Conference on Competition and Coordination in the Electricity Sector, Toulouse, France, January 16-17, 2004.

"Estimating Structural Change in Industries with Application to Cartels," June 2003.

"The Pollution Control and Management Response of Thai Firms to Formal and Informal Regulation," (with Theodore Panayotou) draft, 1999.

"Differential Industry Response to Formal and Informal Environmental Regulations in Newly Industrializing Economies: The Case of Thailand," (with Theodore Panayotou and Qwanruedee Limvorapitak), Harvard Institute for International Development 1997 Asia Environmental Economics Policy Seminar, Bangkok, Thailand, February 1997.

"The Effects of Uncertainty on Landowner Conversion Decisions," John F. Kennedy School of Government, Center for Science and International Affairs, Environment and Natural Resources Program, Discussion Paper 95-14, December 1995.

SELECTED PRESENTATIONS

"Market-Based Policies to Address Climate Change," Sustainable Middlesex, May 4, 2013.

"Market Forces and Prospects/Economic Ripple Effects, 5-10 Years Ahead," Air & Waste Management Association, New England Section, October 12, 2012.

"Gas and Electric Coordination: Is It Needed? If So, To What End?" Harvard Electric Policy Group, Cambridge, MA, October 11, 2012.

"Reliability and Resource Performance," Center for Research In Regulated Industries 31st Annual Eastern Conference May 16, 2012.

"Can Cost Containment Raise Costs? Allowance Reserves in Practice," International Industrial Organization Conference, Boston, MA, April 9, 2011.

"Ratemaking Mechanisms/Tools as Carrots for Achieving Desirable Regulatory Outcomes," Conference on Electric Utility Rate Cases, Law Seminars International, Boston, Massachusetts, November 9, 2010.

"Evolving Issues in Revenue Decoupling: Designs for an Era of Rising Costs," Center for Research In Regulated Industries 29th Annual Eastern Conference May 19, 2010.

"Aligning Interest with Duty: Revenue Decoupling as a Key Element of Accomplishing Energy Efficiency Goals," National Conference of State Legislatures, Fall Forum, December 8, 2009.

"Federal Proposals to Limit Carbon Emissions and How They Would Affect Market Structures – Regional Trading Programs' Futures in Light of New Federal Interest in Reducing GHG Emissions," Energy in California, Law Seminars International, San Francisco, California, September 15, 2009.

"Current Market, Technology and Regulatory Risks: Impact on Investment and Implications for Policy", Utility Rate Case, Issues and Strategy 2009, Law Seminars International, Las Vegas, Nevada, February 9, 2009.

"An Economic Perspective on the Benefits of Going Green," Harvard Electricity Policy Group, Atlanta, Georgia, December 11-12, 2008.

"Implications of Current Regulatory, Technology and Market Risks," Energy in California, Law Seminars International, San Francisco, California, September 22-23, 2008.

"Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices," National Association of Regulatory Utility Commissioners Summer Committee Meetings, Portland, Oregon, July 20, 2008.

"Too Good to Be True? An Examination of Three Economic Assessments of California Climate Change Policy, Key Findings and Lessons Learned," POWER Research Conference on Electricity Markets and Regulation, University of California at Berkeley, March 21, 2008.

"Preliminary Findings: Study of Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," National Association of Regulatory Utility Commissioners Annual Meeting, Washington, D.C., February 17, 2008.

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Attachment B

FCM Pay For Performance Impact Assessment

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Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives

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September 2013

Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives

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I. EXECUTIVE SUMMARY

Through its Strategic Planning Initiative (SPI), the New England Independent System Operator (ISO-NE) has identified multiple reliability concerns tied in part to the performance of generating resources in the region, including those with Capacity Supply Obligations (CSOs) made through ISO-NE's Forward Capacity Market (FCM). Concerns over performance include the potential failure of units to procure fuel, including natural gas-dependent resources during periods of limited gas supplies (particularly during the winter gas season),[1] and the failure of resources to closely follow dispatch requests when needed to address contingencies.[2] While these performance concerns exist today, the SPI recognized that they could become more important in the future, as aging units retire and the region integrates increased levels of renewable resources.

ISO-NE has taken a number of steps to address performance and reliability concerns in the near term, including, for example, an energy procurement (from non-gas resources) for Winter 2013/2014, and multiple changes to energy markets to mitigate coordination problems between gas and electric markets.[3] In addition, as a long-term solution to performance and reliability concerns, ISO-NE has proposed to modify the current FCM to include a Performance Incentives (PI) mechanism that would increase the current incentives for operational performance by providing additional revenues to resources that supply power (or reduce demand) during periods of the greatest system need. Under the FCM PI mechanism, these incentives are created through payments *between resources*, rather than between resources and load (customers) based on performance during reserve shortages. With each reserve shortage, higher performing resources would receive positive incremental payments, while resources that perform poorly would receive negative incremental payments. Thus, the aggregate payments by load (customers) will not exceed the fixed FCA prices regardless of the level of reserve shortages in the commitment period.

This report provides an Impact Assessment of the proposed FCM PI market rule changes, and its analyses are performed consistently with ISO-NE's framework for evaluating "major" initiatives, under which ISO-NE "will provide quantitative and qualitative *information* on the need for and the impacts, including costs, of the initiative"[4] (emphasis added). Thus, the Impact Assessment is designed to provide stakeholders with information about the possible impacts of the FCM PI proposal, including the potential benefits (including reliability improvements), costs, impacts on consumer payments, and other changes relevant to policy goals. However, it is not designed to provide a systematic evaluation of costs and benefits of the proposed rule, nor is it a forecast of FCM market outcomes.

[1] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[2] Analysis Group, *Analysis of Reserve Resources: Activation Response Following Contingency Events*, May 29, 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

[3] *See*, ISO-NE, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

[4] ISO-NE and the Brattle Group, "Framework for Evaluating Major Initiatives," January 2011. Available at: http://www.iso-ne.com/pubs/spcl_rpts/2011/major_iso_initiatives_impact_analysis_final_report_1_28_11.pdf.

Market and system resource outcomes are evaluated through a quantitative model of bidding in the Forward Capacity Auction (FCA) for the 2018/2019 Commitment Period (FCA 9). The model allows comparison of outcomes with and without FCM PI, and comparisons between alternative proposals to address reliability concerns. Outcomes are evaluated under different assumptions about overall system conditions, including scenarios reflecting current ("Historical") conditions and postulated future conditions ("Equilibrium" scenarios). In addition, scenarios reflecting different levels of system reliability associated with limited gas fuel supplies are evaluated.

Table E1 summarizes these scenario results. Conclusions regarding impacts for reliability, costs and customers payments are as follows.

Table E1: Market and System Outcomes under Historical and Equilibrium Scenarios

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$1.93	$2.55	$2.91	$3.76	$3.76	$4.49
Total FCM Payments ($bil)	$0.54	$0.80	$1.06	$1.20	$1.56	$1.56	$1.86
Avg FCM Payments ($/MWh)	$4.07	$5.99	$7.92	$9.01	$11.68	$11.66	$13.92
% Change Relative to 2012 Level	-57%	-36%	-15%	-4%	25%	25%	49%
New Entry Offers ($/kW-month)	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Surplus Capacity Above ICR (MW)	0	0	0	0	1,036	1,390	1,472
Expected Reserve Shortage Hours	21	-	-	-	9.00	10.00	12.75
Summer Peak RS Hours	21	-	-	-	9.00	7.00	6.75
Winter Gas-Related RS Hours	-	-	-	-	0.00	3.00	6.00
Incremental Dual Fuel Capacity (MW)	0	226	5,848	7,368	39	6,130	7,988

Note: For the Historical Scenario, Expected Reserve Shortage Hours are not reported as they do not reflect a consistent market-system equilibrium.

These results of this quantitative analysis indicate that FCM PI would likely result in improvements to reliability through several mechanisms.

First, the quantity of resources continuing to participate in the ISO-NE markets would increase under FCM PI compared to current market rules as a result of the additional revenues provided by performance incentives. In the near-term, estimated surplus capacity (above the Installed Capacity Requirement (ICR)) ranges from 1,036 MW to 1,472 MW with FCM PI in place. By comparison, the analysis finds there is no surplus economic capacity under current market rules.

Second, the analysis indicates that FCM PI would induce actions aimed at mitigating performance risks associated with gas supply curtailments, particularly during the winter gas season. The analysis finds that increased dual fuel capability provides the most cost-effective option to mitigate these risks. To the extent that other options (e.g., contracts with existing LNG resources, new pipeline capacity dedicated for electricity generation) become less costly to market participants than dual-fuel upgrades, our analysis would understate investment in reliability solutions. Across the range of winter gas market conditions evaluated, up to 7,988 MW of additional dual fuel capability is developed. Our sensitivity analysis found that the actual level of new dual fuel capability induced is sensitive to upgrade costs (and other assumptions regarding revenue streams), which suggests uncertainty in the

eventual equilibrium between actions to mitigate gas curtailment risks and the level of such risks. FCM PI would also mitigate any further mothballing of dual-fuel capability that would likely occur absent market incentives, although the analysis does not quantify this risk to reliability (absent FCM PI).

Third, FCM PI would likely shift the resources that remain economically viable in the ISO-NE markets toward a more flexible mix. This likely change in performance can be seen in several analysis results. First, across scenarios, FCM PI decreases the quantity of "economic" (i.e., resources that can operate profitably in the ISO-NE markets) oil-fired resources, while increasing the quantity of economic demand response, imports, gas-fired and coal-fired resources. Second, because of FCM PI incentives, higher performing resources are more likely to continue to participate in the ISO-NE markets. Consequently, average resource performance (as measured by output during reserve shortages) of economic resources increases. The option to adopt dual fuel capability allows gas-fired resources with gas dependency risks to continue to operate profitably in the ISO-NE markets.

Analysis of the economic impacts of FCM PI considers both the costs of meeting customer loads, and the payments made by loads for wholesale market services.

FCM PI would result in a variety of cost impacts, with ambiguous near-term and long-term aggregate impacts. Impacts would include: potential changes to production costs due to a fleet of more efficient resources; new investments and higher annual costs to improve resource performance (including dual fuel capability investments of up to $462 million in the "high gas" scenarios); and potential delays in the timing of when new generation resources are required to meet the ICR.

The analysis indicates that FCM PI would likely raise FCA prices under most market conditions until the system requires additional generation resources, when FCM PI would likely lower FCA prices. The analysis finds that FCM prices in FCA 9 would be $1.31 per kW-month under current market rules, but would range from $1.93 per kW-month to $4.49 per kW-month across the various scenarios evaluated with FCM PI in place. However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Consequently, in the long-run, FCM PI could lower FCA prices as the market nears an equilibrium in which new generation resources are required. Increases in FCM payments under the Equilibrium scenarios (relative to 2012 levels) would reflect a 5% to 10% increase in 2012 wholesale energy payments.

The analysis indicates that total FCM payments would increase under FCM PI, although the net impact of increases in FCM expenditures, estimated at $0.26 billion to $1.32 billion across scenarios, would likely be lower due to reductions in energy market payments because of surplus capacity. Changes in energy market payments arising from surplus capacity are not quantitatively evaluated. Surplus capacity will also diminish the level of reserve shortages, which in turn reduces Reserve Constraint Penalty Factor (RCPF) payments. Based on current RCPF prices and the difference in the number of reserve shortages, the reduction in RCPF payments could range from about $63 to $265 million.

II. INTRODUCTION AND STUDY PURPOSE

Through its Strategic Planning Initiative (SPI), the New England Independent System Operator (ISO-NE) has identified multiple reliability concerns that appear to be tied in part to the performance of generating resources in the region, including those with Capacity Supply Obligations (CSOs) made through ISO-NE's Forward Capacity Market (FCM). Concerns over performance include the potential failure of units to procure fuel, particularly natural gas-dependent resources during periods of tight gas supplies (particularly during winter gas season),[5] and the failure of resources to closely follow dispatch requests when needed to address contingencies.[6] While these performance concerns exist today, the SPI recognized that they could become more important in the future, as aging units retire and the region integrates increased levels of renewable resources. The SPI also identified other reliability concerns, such as the need for more flexible resources to ensure reliable integration of variable resources. While perhaps not as urgent for New England at present, these reliability concerns could emerge in the longer term, as evidenced by developments in other regions, notably California.[7]

ISO-NE has taken a number of steps to address performance and reliability concerns in the near term, including, for example, an energy procurement (from non-gas resources) for Winter 2013/2014, and multiple changes to energy markets to mitigate coordination problems between gas and electric markets (e.g., the timing of day ahead energy market offers and clearing, the timing of supplemental commitments, and energy market reoffers during the real-time market). In addition, as a long-term solution to performance and reliability concerns, ISO-NE has proposed to modify the current FCM to include a Performance Incentives (PI) mechanism that would increase the current incentives for operational performance by increasing revenues to resources that supply power (or reduce demand) during periods of the greatest system need. This proposal is described in further detail in Section III of this report.

This report provides an Impact Assessment of the proposed FCM Performance Incentives market rule changes. The assessment has been developed in a manner consistent with the "Framework for Evaluating Major Initiatives" developed by ISO-NE, which provides guidelines for developing quantitative and qualitative *information* for evaluating "major" market design and planning initiatives.[8] While designed to provide stakeholders with information about possible *impacts* of the proposed rule changes (relative to current rules), including the potential benefit, costs, impact on consumer payments, and other changes relevant to policy goals, the Impact Assessment is not designed to provide a systematic evaluation of costs and benefits of the proposed rule, nor is it a forecast of FCM market outcomes. Impact analyses are developed for major market rule initiatives to improve the quality of stakeholder

[5] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[6] Analysis Group, *Analysis of Reserve Resources: Activation Response Following Contingency Events*, May 29, 2012. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/analysis_group_reserve_resource_analyses_5_29_2012.pdf.

[7] See, e.g., *Long Term Resource Adequacy Summit*, presentation by Mark Rothleder, California ISO, February 26, 2013. Available at: http://www.caiso.com/Documents/Presentation-Mark_Rothleder_CaliforniaISO.pdf.

[8] ISO-NE and the Brattle Group, "Framework for Evaluating Major Initiatives," January 2011. Available at: http://www.iso-ne.com/pubs/spcl_rpts/2011/major_iso_initiatives_impact_analysis_final_report_1_28_11.pdf.

deliberations, thus leading to better and more informed decisions based on the underlying merits of the proposals. Our Impact Assessment accomplishes this by providing both quantitative and qualitative assessment of the likely impacts of the FCM PI proposal, including changes to resource supply, mix and capabilities that have implications for system reliability; changes to production costs; and changes to market outcomes arising from FCM and energy market price effects.

The next section provides background on the FCM PI design. Following this, Section IV describes the analytic method for our Impact Assessment, and Section V outlines the data and assumptions applied in the analysis. Sections VI and VII present the result of our analysis, including the evaluation of both the FCM PI design and an alternative design proposed by NRG. Finally, Section VIII presents conclusions based on the analysis.

III. BACKGROUND ON FCM PERFORMANCE INCENTIVES PROPOSAL

ISO-NE is proposing FCM PI as a means to address concerns about the performance of resources that have taken capacity supply obligations under the FCM. Based on its assessment of resource performance under a variety of conditions, ISO-NE has concluded that the current approach to ensuring resource adequacy may not provide sufficient incentives for resources to perform when needed the most – that is, during reserve shortages. FCM PI is therefore designed to provide incentives for resource performance by rewarding resources that contribute to maintaining reliability by supplying output during periods of greatest system need. ISO-NE describes the approach as follows:

> The ISO proposes to modify the FCM design to make each resource's FCM revenue contingent, in part, upon its actual performance during periods when aggregate performance does not enable the ISO to satisfy system reserve requirements. The new performance incentive design will result in transfers from under-performing to over-performing resources, providing strong incentives for each resource to perform as needed and for resources that can meet the system's needs by exceeding their obligation to benefit by doing so. These incentives will place performance risk on all FCM resources, and this risk will need to be priced in each resource's bid in future capacity auctions.[9]

The FCM PI proposal operates under the simple principle that increasing payments for supply during periods of high reliability risk (as reflected by reserve shortages) provides the clearest incentive for resources to operate reliably during these periods. By using a market-based approach tied to an indicator that captures a wide range of reliability risks, FCM PI is designed to address any current or future risks to system reliability that may arise. Moreover, FCM PI addresses these risks through price signals that allow resources to mitigate these risks through the most cost-effective (i.e., least costly) actions. More information on the purpose and design of FCM PI may be found in Committee meeting materials and in ISO-NE's FCM Performance Incentives paper.

The FCM PI proposal includes several elements relevant to our Impact Analysis. First, under FCM PI, capacity supply obligations will still be established through the Forward Capacity Auction

[9] ISO-NE, "FCM Performance Incentives," October 2012. Available at http://www.iso-ne.com/committees /comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.

(FCA) performed three years prior to the commitment period, and resources clearing in the FCA will still receive a price (P_{FCM}) for each unit of capacity that clears the FCA. Thus, the fixed revenue stream resources receive under current FCM rules will remain in place with FCM PI.

Second, FCM PI provides performance incentive payments to *all* resources that supply output during reserve shortages. These additional payments are set based on the quantity of output supplied (*MW*) and the Performance Payment Rate (*PPR*), set in terms of dollars per MWh (e.g., $5,455 per MWh). Thus, resources that supply output when the system is in greatest need are rewarded for their performance.

Third, for all resources with a CSO, FCM PI adjusts incentive payments to reflect the system average performance needed at the time of the reserve shortage. The benchmark for this average performance is the "balancing ratio" (*BR*), which is measured as the ratio of the system load when the reserve shortage occurs divided by the Installed Capacity Requirement (*ICR*). Thus, incentive payments are adjusted to reflect the size of each resource's capacity commitment (i.e., its CSO), the balancing ratio, and the *PPR*. In effect, FCM PI acts like a financial option. In exchange for taking on the CSO and receiving fixed FCM base payments, resources agree to pay an amount equal to *PPR*BR* (for each MW of a CSO) every time there is a reserve shortage. Across all resources in the region, this option hedges both resources and load from the financial risk associated with uncertainty about the future level of reserve shortages. Thus, the payments by load (and the FCM revenues to suppliers) remain fixed at the price set during the FCA regardless of the level of actual reserve shortages during the commitment period.

The revenue stream to an individual resource under FCM PI is:

$$R = P_{FCM} * CSO + \sum PPR * \left(MW - CSO * BR \right)$$

where the change to revenue streams from PI and the downward balancing ratio adjustments occur over all reserve shortages during the commitment period.

With the balancing ratio adjustments, the net effect of FCM PI for a particular resource depends on how well it performs compared to system needs, as reflected in the balancing ratio. Resources with "above average" actual performance (i.e., $MW > CSO * BR$) are rewarded for their performance by receiving positive revenue adjustments, while those with "below average" actual performance (i.e., $MW < CSO * BR$) are penalized for their performance through negative revenue adjustments. These adjustments to FCM revenues for resource performance will result in changes to FCA offers depending on a resource owner's expectations about the performance of their resource and other factors that could affect PI payments (e.g., the level of reserve shortages). The implications of FCM PI for resource offers are described further in Section IV.A, below.

FCM PI also introduces new uncertainties for resources. Whereas current FCM revenues depend only on the fixed FCM price *P*, FCM PI revenues will ultimately depend on factors not known to resources when their FCA offers are submitted. Thus, FCM PI introduces uncertainty over FCM revenue streams that will have implications for financial risk, which is addressed in Section V.F, below.

IV. FRAMEWORK FOR ASSESSING THE IMPACT OF PERFORMANCE INCENTIVES

The impact of FCM PI is assessed through a comparison of FCM market outcomes with and without FCM PI. Market outcomes reflect an equilibrium between the offers to take on CSOs made by market participants, and the quantity of CSOs required (equal to the ICR). ICR is determined by ISO-NE prior to the relevant FCA. In our analysis, we assumed the ICR was set at 34,500 MW, based on an ICR forecast for the 2018/19 capacity year developed in the Regional System Plan (RSP).[10] Given uncertainty over this quantity, we also consider values three percent higher and lower than this forecast.

A. Resource Offers With and Without FCM PI

Under the current FCM, offers to take on a CSO by existing and new resources reflect estimates of the incremental revenues required for the resource to "break-even" financially. This "break-even" amount reflects a resource's Going Forward Cost (*GFC*), which under current market rules must equal its expected avoidable costs from delisting (retiring) the resource (*FC*) (including the annualized cost of avoided investment, *I*) less its expected net revenues in ISO-NE energy and ancillary services markets. More specifically, under current rules, resource offers (in dollars per kW-month) equal:[11]

$$Offer(FCM) = \frac{GFC + RF}{Capacity * 12} = \frac{FC + I - Q * \left(P - VC - HR * P_{Fuel}\right) + RF}{Capacity * 12}$$

The GFC reflects net energy and ancillary services market revenues, where *Q* is the quantity of output sold, *P* is the average energy market price, *VC* is the non-fuel variable costs, *HR* is the unit's heat rate, and P_{Fuel} is the fuel price. The last term, *RF*, is the risk factor. A risk factor is added to offers to account for financial risks taken on by market participants when they agree to CSO contractual terms. Current market rules allow market participants to account for a defined set of risks related to unanticipated plant outages and potentially other factors. Given that *GFC* reflects costs during a future capacity commitment period, all values reflect forecasted or expected values. Appendix A provides details on how each of these values is estimated.

FCM PI introduces several changes to resource offers. First, for resources that require FCM base payments (i.e., based on the fixed price, P_{FCM}) to remain in the ISO-NE energy market, resource offers will reflect the unit's *GFC* plus expected revenues from FCM PI – that is:[12]

$$Offer(FCM\ PI) = GFC - PPR * H * \left(A - BR\right) + RF$$

[10] ISO New England, *2012 Regional System Plan*, November 2, 2012, page 45. Available at http://www.iso-ne.com /trans/rsp/2012/rsp_final_110212.docx.

[11] This formula reflects current market rules for net risk-adjusted going forward costs, as described in Market Rule 1, Section III.13.1.2.3.2.1.2. Throughout, the calculation of going forward costs is developed in a manner consistent with these market rules.

[12] Resources will require FCM revenues to remain in the market if going forward costs, net of PI revenues and the risk factor, are positive – that is: $GFC - PPR * H * A + RF > 0$. Our analysis does not account for certain factors that could affect actual offers, including capital investment needed to continue production and option value given potential future positive changes in revenue streams.

where *H* is the *expected* level of reserve shortages (measured in hours), *A* is the unit's *expected average* performance over the course of the year, and *BR* is the *expected average* balancing ratio over the course of the commitment period.[13] Average performance *A* is measured as a unit's average output during reserve shortages (in MW) divided by its CSO. For example, a resource with a 100 MW CSO that produced average output of 65 MW during reserve shortages would have average performance *A* equal to 65%. Consequently, compared to the current market rules, FCM PI will result in upward and downward adjustments to offers depending on how each resource's *expected* average performance compares to the *expected* balancing ratio during reserve shortages.

Second, when submitting offers, resources can consider the option to forego a CSO. Without a CSO, market participants continue to receive positive PI payments for output from their resources. With a CSO, resources earn both the fixed FCM price and the positive incentive payment, but must consider the downward adjustments to revenues based on the balancing ratio (i.e., $PPR * CSO * BR$). Given this choice, in order to take on the CSO, market participants must receive a minimum payment that offsets the *expected* downward balancing ratio adjustments, which they could otherwise avoid by foregoing the CSO. Consequently, with PI, resources' offers will equal or exceed a minimum offer equal to their expectation of these downward adjustments – that is:

$$Minimum\,Offer\left(FCM\ PI\right) = PPR * H * BR + RF$$

This minimum offer differs from current market rules, under which some resources will be willing to accept a minimum offer as low as $0 per kW-month.

Third, resources taking on a CSO may face less or greater financial risk due to the financial hedge provided by the CSO compared to uncertain (but positive) net PI payments. Consequently, the risk factor *RF*, reflecting financial risk due to the uncertain revenue streams from accepting a CSO, included in resource offers may differ under FCM PI compared to current market rules. Note that, in theory, this adjustment could be upwards or downwards depending on the resource's expected performance and the aggregate risk profile of the entity that owns the asset.

To determine the clearing prices in the FCA, offer curves are constructed, reflecting the bids from each resource ordered from lowest to highest priced offers. Offer curves are developed for the 2018/2019 FCA with and without FCM PI. Offers are developed assuming resources offer their entire capacity as a single block, rather than as multiple blocks as allowed under the proposed rules. Section V describes how each of the individual terms in the offer formulas described above is calculated.

B. Scenarios Evaluated

A significant uncertainty affecting the analysis relates to the likely resource and system conditions in the 2018/2019 Commitment Period. These conditions affect key factors that must be

[13] For further discussion of the calculation of expected FCM payments *see* Gillespie, Andrew et al., ISO-NE, "FCM Performance Incentives," NEPOOL Markets Committee, April 9-10, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps /mrkts_comm/mrkts/mtrls/2013/apr9102013/a17a_iso_presentation_04_10_13.ppt.

considered in developing resource offers, including the likely level of reserve shortages hours, and the likely resource performance and balancing ratio during those shortages.

Current market conditions may not be a reliable predictor of future market conditions for several reasons. First, the price floor that supports the FCM price has resulted in a supply of resources in the ISO-NE region well in excess of the ICR. Starting in FCA 8 (for the 2017/2018 Commitment Period), the price floor will be removed, which could lead some resources to temporarily or permanently exit the market; this, in turn, would affect system conditions. Second, ISO-NE has identified that gas fuel supply limitations (particularly during winter months) pose a meaningful risk to system reliability.[14] While ISO-NE has taken many steps to improve the market's ability to mitigate these risks (e.g., intra-day reoffers, hourly offers, adjustment to the timing of the day ahead market, increases in the Reserve Constraint Penalty Factor (RCPF) for 30-minute system reserves, procurement of requirements for 30-minute "replacement" reserves)[15], this reliability risk could increase with time, particularly if resources retire due to lower FCM revenues or other economic factors.[16]

Given these uncertainties, the impacts of the FCM PI proposal are evaluated under multiple sets of assumptions regarding system conditions in order to identify the range of potential outcomes and the robustness of conclusions. Table 1 lists the scenarios and sensitivity cases we evaluated. At one end of the spectrum are "Historical" scenarios reflecting system conditions that have prevailed in recent years. However, given the potential for a net reduction in the region's resources (particularly with the removal of FCA price floors), we also develop a near-term Equilibrium scenario which reflects a postulated balance between forecast system conditions and expected market conditions in 2018/2019. For reasons we describe below, this scenario is a reasonable upper bound on prices. This near-term equilibrium may differ from a long-run equilibrium, where the system requires the entry of new generation resources to maintain resource adequacy. While we do not explicitly postulate long-run equilibrium conditions for 2018/2019, some of our results are informative to understanding outcomes under such conditions.

Along with uncertainty about system conditions, there is also uncertainty about the expected level of reserve shortages that arise specifically from limitations to gas supplies. While ISO-NE has taken steps to mitigate reliability risks related to coordination of gas and electric markets, these market enhancements are not expected to eliminate all reliability problems, particularly those arising when there are insufficient resources with fuel supply to meet load. To assess possible system conditions associated with winter gas reliability risks, additional scenarios are evaluated assuming there are 3 or 6 hours of reserve shortages associated with limited gas supply during winter months. Table 1 identifies the six scenarios we analyze, reflecting the different potential system conditions described above.

[14] For example, *see* ISO-NE, "Winter Operations Summary: January-February 2013", February 27, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/winter_operations_summary_2013_feb_%2027_draft_for_discussion.pdf.

[15] *See*, ISO-NE, "Interdependencies of Market and Operational Changes to Address Resource Performance and Gas Dependency," 2013. http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/interdependency_of_iso_proposals_to_key_spi_risks.pdf.

[16] For example, Entergy has announced the retirement of the Vermont Yankee nuclear plan. Available at http://www.safecleanreliable.com/entergy-to-close-decommission-vermont-yankee-2.

In addition to these scenarios, we also consider the sensitivity of results to multiple underlying assumptions related to resource availability and costs, including elimination of offer risk factors; costs for compliance with environmental regulations (Clean Water Act (CWA) Section §316(b) cooling water intake requirements); the cost of dual fuel upgrades; and limitations on the ability of gas-dependent resources to develop dual fuel capability. These sensitivities and the underlying model assumptions are also included in Table 1.

Table 1: Alternative Scenarios and Sensitivities Considered

		Winter Gas Dependency Risks		
		No Gas Shortages	**Gas Shortages**	**High Gas Shortages**
Overall Resource Adequacy	**Current ("Historical") System Conditions**	Historical: No Gas	Historical: Gas	Historical: High Gas
	Near-term Equilibrium System Conditions for 2018/2019	Equilibrium: No Gas	Equilibrium: Gas	Equilibrium: High Gas

Sensitivity	**Model Assumptions**
Risk Factor	• Use Equilibrium: No Gas Scenario • No Risk Factor
Environmental Costs	• Use Equilibrium: No Gas Scenario • Incremental costs for compliance with CWA Section §316(b) Cooling Water Intake Requirements (Section V.E provides details on costs)
Dual Fuel Costs	• Use Equilibrium: Gas Scenario, and Equilibrium: High Gas Scenario • Increase dual fuel upgrade costs by 25% • Results reported/discussed in Section VI.A.2 (all other sensitivities reported/discussed in Section VI.D)
Dual Fuel Restrictions	• Use Equilibrium: High Gas Scenario • Limits dual fuel adoption to those already with decommissioned dual fuel capability

V. DATA AND ASSUMPTIONS

A. Going Forward Costs

Section IV.A provides the basic framework for calculating each unit's going forward cost (GFC). Each unit's GFC for the 2018/2019 Commitment Period is based on a combination of data on current operation costs, past utilization rates, and forecasts of future fuel prices. Future electricity prices are

estimated based on the past relationships between natural gas prices and the average prices earned by resources when operating. Estimates rely on a variety of data sources, including: SNL for unit-level fixed costs, non-fuel variable costs, and heat rates; EIA and NYMEX for fuel price forecasts; and ISO-NE for historical output and prices. Appendix A provides details on the data and approaches used.

B. Estimating Unit Performance and Balancing Ratio During Reserve Shortages

Unit performance and the balancing ratio are estimated to reflect the system conditions during reserve shortages under the scenarios evaluated for the 2018/2019 Commitment Period. Three system conditions are considered:

1. Historical Conditions, corresponding to average conditions in recent years, with the current level of surplus resources;
2. Peak (Summer) Conditions, corresponding to reserve shortages arising as a consequence of an inadequate level of resources to meet load; and
3. Winter Peak Conditions, corresponding to reserve shortages arising due to limitations on natural gas supplies during the peak winter gas season.

Average performance is measured for each unit based on output supplied during reserve shortages over the period 2010 to 2012. Estimates of likely performance during Historical, Peak (Summer) and Winter conditions are based on actual performance during reserve shortages that reflect these types of system conditions. Thus, for example, estimates of unit performance and the balancing ratio during reserve shortages due to resource adequacy risks (i.e., Peak Summer Conditions) are based on reserve shortages during the 2010 to 2012 period that also occurred due to insufficient aggregate resources.[17] Balancing ratios are estimated in a consistent fashion.

Figure 1 shows the average performance by resource type for each of the three market conditions described above, along with the balancing ratio during the corresponding time periods. Tables 1 to 3 in Appendix A provide additional statistics on average performance *A* across the same set of units. These additional tables show some skewing of performance within resource categories with larger resources tending to demonstrate higher performance.

[17] Other reserve shortages during the 2010 to 2012 time period occur due to other factors, including having insufficient resources committed to respond to unanticipated changes to load or supply.

Figure 1: Average Unit Performance by Resource Category

[1] Unit performance for each class is calculated as total class output divided by total class summer SCC. The summer SCC used is from the most recent year with available data.
[2] Summer SCC, generation type, and primary fuel type from CELT Reports. Operating data from ISO-NE.

Resource performance varies widely across resource categories. Nuclear power has the highest non-renewable performance because, as baseload resources, they operate under all market conditions. Gas turbines also have high performance because these resources are capable of starting quickly under circumstances when the market needs additional resources to meet load plus reserve requirements. Combined cycle and coal resources have somewhat lower performance because when reserve shortages occur these resources may not be committed or able to ramp up to their full operating capacity, if there is limited foreshadowing of the need for additional resources to meet load plus reserve requirements. Non-CT oil-fired resources have the lowest performance because many of these facilities are operated only when prices are sufficiently high to merit operation, or when there is sufficient foresight that the system will need additional resources to maintain reserve levels. Renewable resource performance varies with the particular characteristics of each type of resource. Wind resources have average performance that exceeds their eligible capacity, because FCM eligible capacity represents only of faction of the nameplate capacity of these resources. Hydro performance is high, potentially reflecting either high utilization or control of the timing of output. Pumped storage performance is below that of other hydro, suggesting either that reservoirs have been drained or have not been filled prior to reserve shortages.

Comparison of resource performance to the balancing ratio provides an indication of how each resource category fares under PI. Resources with performance above the balancing ratio would receive positive revenue adjustments, while those with performance below the balancing ratio would receive negative revenue adjustments. While the average performance levels reported in Figure 1 are indicative of the resource category performance, there is substantial variation in the performance within each category and the performance of individual units may differ from these category averages.

C. Reserve Shortage Hours

The level of reserve shortages is measured by the expected number of hours of reserve shortages over the 2018/2019 Commitment Period. The level of reserve shortages for each scenario evaluated is reported in Table 2. For the Historical Scenarios, the level of reserve shortages is based on market conditions from 2010 to 2012, when there was an average of 3.2 hours of reserve shortages annually.[18] Consequently, we assume 3.2 reserve shortage hours in the Historical Scenarios, to reflect current market conditions.

Near-term equilibrium conditions reflect a balance between system and market conditions for FCA 9, which procures commitments for the 2018/2019 Commitment Period. This near-term equilibrium will reflect resources that remain in the market due to FCM revenues, as well as resources that stay in the ISO-NE energy and ancillary services market without a CSO.

Under the current FCM market rules, resources that do not clear in the FCM do not have an obligation to remain in the market. However, assuming that delist offers reflect going forward costs (and

[18] This average reflects a combination of shortages due to insufficient resources (i.e., high loads relative to resources) and shortages due to unanticipated system conditions (particularly when there are insufficient resources committed).

that the FCA clearing price is greater than zero), failure to clear the market suggests there is a meaningful likelihood that a resource will exit the market.[19]

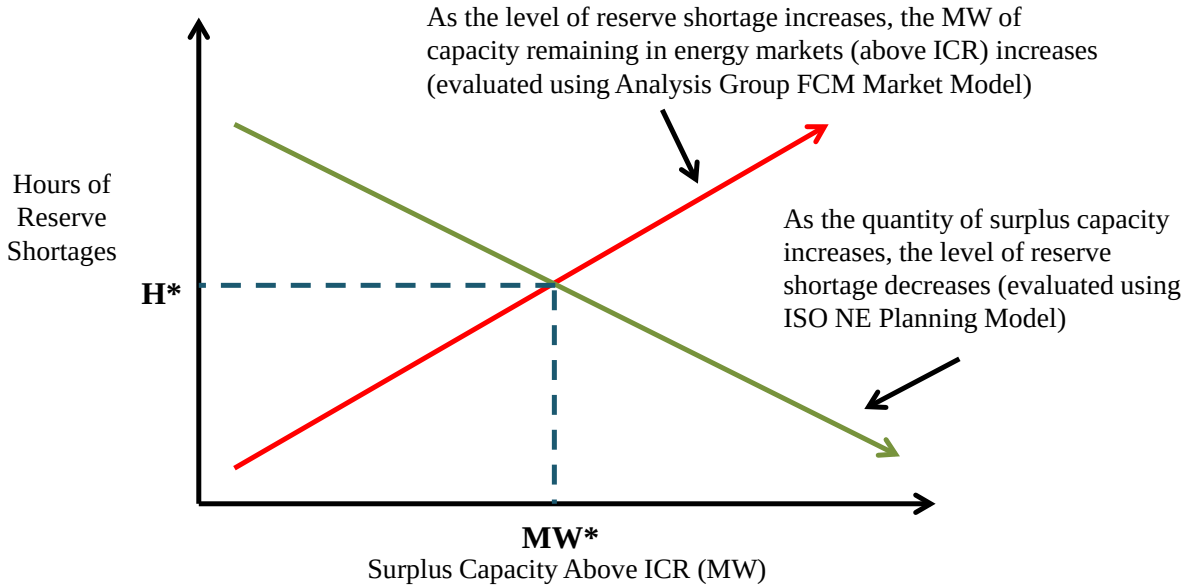
Table 2: Reserve Shortage Hours by Scenario

	Reserve Shortage Hours			
Scenario	**Historical**	**Peak (Summer)**	**Winter Gas**	**Total**
Historical: No Gas	3.2	0	0	3.2
Historical: Gas	3.2	0	3	6.2
Historical: High Gas	3.2	0	6	9.2
Equilibrium: No Gas	0	9	0	9
Equilibrium: Gas	0	7	3	10
Equilibrium: High Gas	0	6.75	6	12.75
No Risk Factor	0	9	0	9
Environmental Costs	0	9	0	9
Higher Dual Fuel Costs	0	7/6.75	3/6	10/12.75
Dual Fuel Restrictions	0	6.75	6	12.75

By contrast, under FCM PI, resources may find it financially profitable to remain in the ISO-NE energy market without a CSO. This can occur when the market clears at a price that is below the resource's minimum offer (based on its expectations of the level of future reserve shortages) but the resource does not need the FCM revenues to remain economically profitable (i.e., its going forward costs including PI revenues are less than zero). As the duration and frequency of reserve shortages increases, the additional PI revenue increases the number of "economic" resources that can profitably operate without a CSO. This is illustrated conceptually in Figure 2, which shows with the red line the relationship between the levels of surplus capacity for varying levels of reserve shortages. However, from a system perspective, as the quantity of resources increases, system reliability improves, which reduces the expected duration and frequency of reserve shortages. This is illustrated by the green line on Figure 2. The *equilibrium* level of reserve shortages and surplus capacity reflects equilibrium between these two opposing dynamics. Our analysis of the near-term Equilibrium for FCA 9 assumes the internally consistent level of surplus capacity and reserve shortages hours that arises under this equilibrium.

[19] In practice, resources may not exit due to a variety of factors, including the option of remaining and continuing to operate without an obligation in the hopes of higher future net revenues.

Figure 2: Graphical Depiction of Equilibrium Between Excess Resources and Reserve Shortages



The market model curve is estimated using the FCM PI model described in this report.[20] The system model is a probabilistic simulation model used by ISO-NE to establish ICR for the region given anticipated load and system conditions for the 2018/2019 Commitment Period.[21] The reserve shortages analyzed in this ISO-NE system model are driven by conditions in which there are insufficient resources available to meet load plus reserve requirements. Because reliability risks arising due to insufficient resource adequacy are most significant during summer peak load periods, the reserve shortages identified in the ISO-NE system model occur largely during the summer months.

Our analysis does not explicitly analyze the evolution of the FCM market toward a long-term equilibrium. This equilibrium can be characterized by the retirement of some existing resources and the entry of new resources as the FCM prices reach the cost of new entry. The timing of the retirement of existing resources will depend on many factors, including the degradation of performance (e.g., heat rate) over time, increasing maintenance costs and incremental capital expenditures to plant systems. Because of uncertainty over these factors, we have not attempted to analyze the evolution of market outcomes towards such an equilibrium. However, below we provide certain quantitative and qualitative information to inform understanding of how PI will affect the timing of and prices at the long-run equilibrium.

[20] Our analysis assumes that resources that either do not accept a CSO or that have insufficient expected revenues to operate profitably in the ISO-NE energy markets will (temporarily or permanently) exit these markets. To the extent that resources do not exit due to a positive option value to continue operations given potential profitable operation in future commitment periods or other factors, then our results would tend to understate the supply of excess resources relative to what would actually happen, which in turn would overstate the expected level of reserve shortages.

[21] ISO-NE Market Development, "Operating Reserve Deficiency Information – At Criteria And Extended Results," July 5, 2013. Available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_memo_07_05_13.pdf.

Analysis of reserve shortages arising from limitations on gas supply during winter months is performed by evaluating market outcomes with two different levels of winter reserve shortages: 3 and 6 hours of winter gas shortages.[22] As with reserve shortages arising due to insufficient resources to meet load and reserve requirements, shortages arising due to over-reliance on limited gas supply will reflect a balance between the number of reserve shortages and the quantity of gas-dependent resources. On the one hand, as the level of reserve shortage hours increases, this creates incentives for resources to take steps to limit their dependence. On the other hand, as resources take steps to limit their gas dependence (in response to these incentives), the number of reserve shortage due to gas dependence would decline. Absent specific data on the likelihood of reserve shortage driven by gas dependence, however, we try to capture this potential impact by modeling up to six hours of gas-driven shortages (in addition to modeling no gas-driven shortages).[23]

Gas shortage scenarios are evaluated under both Historical and near-term Equilibrium conditions. In the near-term Equilibrium scenarios, a separate equilibrium is calculated for each scenario based on the FCM market response with different mixes of summer peak and winter gas reserve shortages. As shown in Table 2, the resulting level of reserve shortages reflects a mix of peak (summer) and winter gas reserve shortages. Equilibrium with winter gas reserve shortages are calculated assuming that equilibrium with the ISO-NE system model reflects only summer peak reserve shortages. This approach is consistent with the fact that a disproportionate number of reserve shortages identified in the ISO-NE system model occur during summer months.

D. Technical Options for Improving Performance

FCM PI is designed to create incentives for asset owners to take steps to improve the performance of existing resources, and/or choose higher performing technologies when investing in new resources. Resource owners can take many steps to improve resource performance, including operational practices to reduce forced outages and improve plant responsiveness to operator requests, investments to improve fast start capability and ramping rates, and actions to firm-up fuel supplies.

Under FCM PI, resources will find it economically beneficial to undertake actions to improve performance when the expected incremental revenues, including PI and other incremental revenues, exceed the costs of the actions taken, including annual expenditures and up-front capital investment. The expected level of incremental PI revenues will depend on multiple factors, including the expected level of reserve shortages and the improvement in the resources' expected performance (output) during these periods.

[22] Even as resources take action to address gas dependence, reserve shortages could remain. For example, the time for many dual fuel resources to switch to alternate fuels varies, such that some resources may require an hour or more to switch. During this period, the system will face resource limits that could result in reserve shortages.

[23] To date, while there have been many instances of reliability challenges tied to gas supply limitations during winter and non-winter months, there is not clear information on the relationship between market conditions related to gas supply and reserve shortages. Due to this fact and the many uncertainties about forecasting future market conditions, we have not attempted to quantitatively model the likelihood of reserve shortages arising from gas dependence.

Our analysis considers potential steps that resources with gas fuel curtailment risks – "gas-dependent resources" – may take to address limited natural gas availability, which would most likely or most often occur during the winter months. We do not consider other actions resources might take to generally improve their operational performance, given the lack of information about such opportunities for individual resources in the region.

The analysis of potential resource responses to FCM PI during winter gas shortages involves two steps. First, we compare the relative cost and effectiveness of alternative means of securing fuel supplies to identify the most cost-effective option. Second, we integrate this option into the FCM supply model such that resources develop dual fuel capability when there are sufficient incremental PI revenues to justify this investment.

Identification of the most cost-effective option for securing winter fuel supplies considered four alternatives:

1. Dual fuel capability
2. Firm or option service from existing Liquefied Natural Gas (LNG) facilities
3. LNG storage
4. Firm transportation services from a new gas pipeline

Table 3 summarizes the results of our assessment of the costs and effectiveness of these alternative options, with further details on our assessment provided in Appendix C. Our analysis of costs reflects the direct expenditures and investments required to implement the technical options for securing fuel supply, but does not consider all changes in revenues or costs that may occur with each option. For example, the costs of firm pipeline service from a new pipeline includes the incremental rates charged for such service, but does not account for the potential reduction in gas transportation costs during periods of tight gas supply (i.e., when the basis differential exceeds the tariff rate). In effect, our analysis considers the least-cost means to address the performance risks that are the focus of this report. While we identify and qualitatively describe differences in the effectiveness of these alternative services at securing fuel supply, this effectiveness does not enter into our identification of the most cost-effective option.

As shown in Table 3, the cost of alternative technologies varies widely. These estimates are based on multiple sources identified in Appendix C, including publicly available data and data provided by ISO-NE, but are not based on detailed engineering studies. Development of dual fuel capability appears to be the least cost option evaluated. Annualized costs range from $6,500 per MW for facilities with moth-balled or decommissioned dual fuel capability to $15,000 per MW for facilities that have never had dual fuel capability.[24] In principle, existing LNG facilities could provide service at a comparable cost to dual fuel capability. The rates for firm or option service provided by these facilities will depend on demand charges that facility owners have some discretion in setting. Costs for new LNG storage are roughly $30,000 per MW, significantly higher than incremental dual fuel costs. Costs for firm transportation service, reflecting the rates charged for such service, are also higher than dual fuel costs.

[24] Annualized costs reported in Table 3 reflect particular assumptions about discounting, depreciation terms and other factors that may differ from those used in the FCM PI analysis, but are comparable across the alternatives for addressing gas-dependency evaluated.

Table 3: Comparison of Options for Firming Gas-Dependent Resource Fuel Supply

Technology Option		Cost	Other Factors
Dual Fuel	Current Dual Fuel Capable	• $5,700 per MW	• Time to recommission or install is relatively brief • Long refill times may limit effectiveness over long curtailments • Operations limits and risks when switching to alternate fuels • Requires environmental permitting
	Under- or Unutilized Dual Fuel Capability	• $6,500 per MW (annualized, reflecting capital cost and annual expenditures)	
	No Dual Fuel Capability	• $15,000 per MW (annualized, reflecting capital cost and annual expenditures)	
Service from Existing LNG Facilities (Canaport, DOMAC)		• Not estimated – cost would reflect (1) foregone opportunity to sell LNG in higher-value markets; (2) carrying cost; (3) operating cost; and (4) transportation charge. • Rate would be subject to negotiation	• Could be subject to deliverability constraints without firm service (esp. for Canaport, requiring transport over Maritimes pipeline)
New LNG Storage		• $29,700 per MW (annualized, reflecting capital cost and annual expenditures)	• Long refill times may limit effectiveness over ong curtailments
New Pipeline Capacity		• $9,700 to $32,700 per MW for upfront costs • Rates for firm service would exceed these annualized costs	• Requires purchase of firm service • Time lag between commitments for firm service and new service availability • Reduces transport costs during periods of elevated prices (when basis differential exceeds tariff rate)

Our analysis allows gas-dependent resources to invest in dual fuel capability if the expected incremental FCM PI revenue streams are sufficient to cover the incremental costs, including any up-front investments and annual expenditures. Incremental FCM PI revenue streams reflect two factors. First, with dual fuel capability, a gas-dependent resource has a higher likelihood of supplying output during a gas supply related reserve shortage. The analysis assumes a 50% reduction in the average performance *A* of gas-dependent resources during winter gas shortages; this assumption is designed to strike a balance within the range of curtailment levels that resources may experience during gas reserve shortages. Investment in dual fuel capability eliminates this reduction, allowing the resource to operate at a normal performance level. For example, a gas-dependent resource with a performance *A* of 70% would operate at a 35% performance during winter gas reserve shortages unless it invests in dual fuel capability. While considering incremental FCM PI revenue streams, the analysis does not account for other changes in net revenues that might arise from dual fuel investment, including changes in energy market revenues. The second factor affecting the incremental revenues from a dual fuel investment is the level of winter gas reserve shortages. For example, if the resource in the example above expects 3 hours of winter gas

reserve shortages, then it would expect to earn an incremental 1.05 MWh during reserve shortages, or $5,728 at a *PPR* of $5,455 per MWh from investing in dual fuel capability.[25]

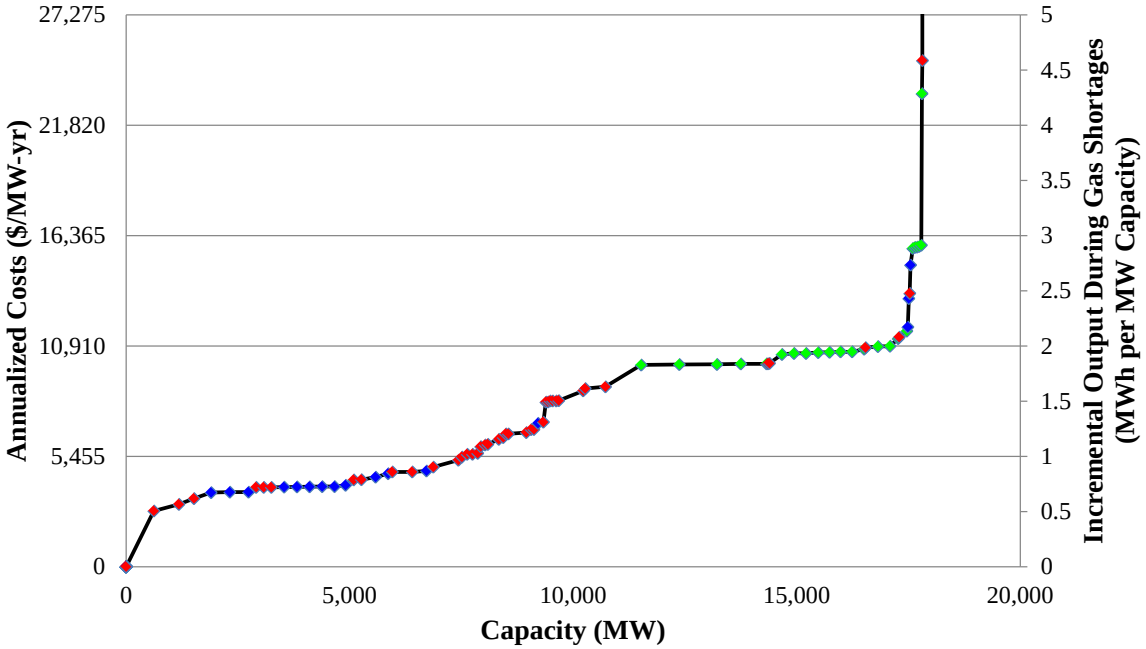
Figure 3 shows the dual fuel supply curve for existing gas-fired resources.[26] This curve includes resources currently without dual fuel capability, as well as resources currently with dual fuel capability that need to incur costs to cover on-going maintenance of dual fuel capability and fuel supplies. The decision to invest in dual fuel capability reflects lower costs for units with mothballed capability, and no limitations arising from environmental permits or other factors. Costs are reported in terms of annual expenditures per MW of capacity, as well as the number of incremental MWh of output during reserve shortages (at a *PPR* of $5,455 per MWh) that is sufficient to cover these annual expenditures. The figure shows that FCM PI can create incentives for investment in dual fuel capability when the resource expects to there to be winter gas shortages in the commitment period. For example, at 2 incremental hour of output during a gas related reserve shortage, roughly 11,000 MW of additional dual fuel capability is supported, including over 7,000 MW of incremental dual fuel capability from resources currently without this capability. Appendix C provides more details on the estimation of costs associated with investment in dual fuel capability.

The analysis assumes that all existing dual fuel resources retain this capability with and without FCM PI. As shown in Figure 3, maintaining dual fuel capability imposes costs on asset owners from on-going maintenance and holding of fuel supplies. Absent market incentives, these resources could opt to mothball this capability, as many resources have already done in recent years. By assuming that resources preserve dual fuel capability absent FCM PI, the analysis may understate FCM PI reliability benefits by failing to capture these potential losses of dual fuel capability.

[25] That is, $PPR * H * (A_{with\ dual\ fuel} - A_{without\ dual\ fuel})$ = $5,455 / *MWh* * 3 *hrs* * 35% = $5,728 / *MW*.

[26] Note that differences between annualized costs in Table 3 and Figure 3 reflect differences in certain assumptions, including discount rates and depreciation periods assumed in each analysis.

Figure 3: Supply Curve for Dual Fuel Resources, including Development and Annual Expenditures



Note: Each symbol corresponds to an individual facility, with existing dual fuel resources in RED, facilities with decommissioned dual fuel capability in BLUE and facilities with no dual fuel capability in GREEN.

E. Potential Environmental Compliance Costs

Compliance with emerging U.S. Environmental Protection Agency (EPA) rules could require that certain facilities undertake additional investments and in future years face additional expenditures in order to obtain permits for continued operation. While EPA has promulgated multiple regulations affecting air emissions, water discharges and waste management from power generation facilities, the regulation most likely to impact facilities in ISO-NE market is Section §316(b) of the Clean Water Act, which requires power plant cooling water structures to meet certain technological requirements in order to minimize adverse environmental impact, largely to aquatic life.[27] Because compliance requirements with these regulations are uncertain, we assume no incremental compliance requirements as the baseline assumption, but consider a sensitivity analysis with additional compliance requirements. In the compliance sensitivity analysis, units must take incremental action to comply with Section §316(b), but some units are left unmodified because their water sources suggest that the units have already made modifications or are unlikely to require retrofits. The identification of resources subject to Section §316(b) requirements reflects both fuel/technology type, and resource age under the assumption that many newer steam units are already compliant with Section §316(b). This case assumes that 50% of the overall capacity

[27] For more information on §316(b), *see* Environmental Protection Agency, "Cooling Water Intake Structures – CWA §316(b)," http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

potentially at risk actually faces additional Section §316(b) requirements, including all coal units, the two oldest nuclear plants, and the oldest oil units.

Compliance requirements have two implications for facility performance. First, compliance imposes additional going forward costs, including upfront investment and annual operating expenditures.[28] Second, the facility's rated capacity is diminished and heat rate is increased.[29] These penalties stem from the efficiency decrease and power required to drive water pumps in the new cooling towers. The adjustment to GFC when compliance requirements are assumed reflects both these direct and indirect cost impacts. Further detail on our approach is provided in Appendix A.

F. Risk Premiums

Market participants may include a risk factor in resource offers under both current rules and proposed rules for FCM PI. Under current rules, the risk factor can reflect certain pre-determined elements. To simplify the analysis, we assume the risk factors incorporated in resource offers without FCM PI equals zero. The remainder of this section addresses risk factors under FCM PI.

FCM PI introduces additional uncertainty about FCM market revenues that can have consequences for the financial risk faced by market participants. Under the current FCM, resources face uncertainty about their future costs and energy market net revenues when developing their offers. However, the revenue stream from the current FCM model is fixed after the FCA clears, assuming resources comply with their capacity obligation. However, with the introduction of FCM PI, future FCM revenue streams depend on system conditions beyond the resource's control (e.g., the frequency and duration of reserve shortages, and the balancing ratio during these shortages) and factors over which it has only partial control (i.e., the resource's performance during future reserve shortages). As a result of these uncertainties, future FCM revenues streams for individual resources will be uncertain, which is not the case under the current FCM model. Moreover, for poorly-performing resources, these downward adjustments could be large enough to erode most of the fixed portion of revenues under FCM PI (based on the fixed FCA price), or even result in negative total FCM payments.

Assessing the financial risk posed by FCM involves many challenges. First, the entities that own resources in the ISO-NE markets vary widely. Some are relatively small, owning several or even only one asset. However, many are large and have a wide variety of physical and contractual assets, along

[28] The going forward cost is based on estimates from: North American Electric Reliability Corporation, "Potential Impacts of Future Environmental Regulations: Extracted from the 2011 Long-Term Reliability Assessment," November 2011. Available at http://www.nerc.com/files/epa%20section.pdf.

[29] Steam turbines are given a heat rate penalty of 1.3% and a capacity penalty of 3.4%. "Electricity Reliability Impacts of a Mandatory Cooling Tower Rule for Existing Steam Generation Units," U.S. Department of Energy Office of Electricity Delivery and Energy Reliability, October 2008, p. 22. Available at: http://www.netl.doe.gov /energy-analyses/pubs/Cooling_Tower_Report.pdf. Nuclear plants are given a heat rate penalty of 1.5% and a capacity penalty of 1% of based on a variety of sources. Wheeler, Brian, "Retrofit Options to Comply with 316(b)," Power Engineering, October 2010. Available at: http://www.power-eng.com/articles/print/volume-114/issue-10/features/retrofit-options-to-comply-with-316-b.html; "Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule," U.S. Environmental Protection Energy, pp. 175, 207-210. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/phase2/upload/2009_03_26_316b_phase2 _devdoc_ph2toc.pdf. No adjustments to operating performance *A* have been made for these impacts.

with other business operations. Some entities own portfolios of generation (and contractual) assets with different performance characteristics, different markets and different geographical locations. The revenue streams received through these assets varies widely depending on the type of asset (gas/oil/nuclear, dispatchable/intermittent, old/new, fast-start/non-fast-start), the particular market (e.g., in New England there is the energy, operating reserves, ancillary services, and RECs along with the FCM) and geographies (including other RTOs and assets supported by long-term contracts). Moreover, some entities have revenue streams outside of wholesale power markets, including transmission, distribution, retail, market-making or even non-electric business entities.[30]

Second, the design of FCM PI partially mitigates financial risks for entities with multiple resources in the ISO-NE market, and creates opportunities for bilateral transactions to mitigate risks. For entities that own multiple ISO-NE resources, differences in the actual performance of those resources will tend to mitigate the risk of any individual resources due to portfolio effects. These portfolio effects are considered in the quantitative analysis of the risk factor. In addition, as discussed earlier, under FCM PI, total revenues to all resources in the region are fixed.[31] Consequently, as a whole, the region's resource fleet is fully hedged against the FCM PI financial risks faced by individual resources. [32] This fact suggests that there are opportunities for bilateral transactions among entities in the region that could mitigate the risks faced by individual entities.

Third, financial products could be developed to help mitigate financial risks. For example, an option could be developed that pays the owner based on the level of reserve shortages during a given period. If market participants with a CSO purchased such a product, then with every reserve shortage they would receive a payment from the option that could offset (to some degree) the downward revenue adjustment based on the balancing ratio.[33]

The likelihood that markets for these FCM PI options or bilateral transactions between market participants would emerge is highly uncertain at this stage. Thus, assessment of risk cannot presume that they will develop. However, to the extent that the analysis indicates that there are high risk premiums associated with FCM PI offers, this suggests that the financial rewards to developing these markets or transactions would be higher, which would increase the likelihood that these mitigating transactions would emerge. Should they emerge, these alternatives would result in additional financial costs, which would be reflected in resource offers through the risk factor. The quantitative analysis of the risk factor under FCM PI does not consider these costs, which would tend to increase resource offers and thereby raise FCA prices under FCM PI.

[30] A recent study indicated that Calpine and NRG were the only two publicly traded merchant generation companies. Brattle Group and Sargent & Lundy, "ISO-NE Offer Review Trigger Prices 2013 Update, Draft Results," presented to NEPOOL Markets Committee, August 7, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a04_brattle_group_presentation_08_07_13.ppt.

[31] As previously noted, there is a small deficit in aggregate payments to generators that reflects the shortage of reserves in relation to the total customer demand (reflecting both load and the reserve requirement).

[32] With each reserve shortage event, resources in aggregate face a deficit equal to the size of the reserve shortage (in MW) times the PPR.

[33] The option could also be specified so that the payoff varied with the balancing ratio in the same manner as the downward revenue adjustments vary with the balancing ratio.

Fourth, risks to operational performance can be mitigated through actions to increase the likelihood that the resource supplies output during reserve shortages. This could include actions to reduce forced outages and failures to respond to system operator dispatch requests, actions to reduce the likelihood of fuel supply disruptions (particularly for gas-dependent resources) and actions to increase the likelihood that the energy-limited resources (such as pumped storage) have energy available to supply. Of course, creating incentives for these sorts of actions is a fundamental purpose of FCM PI. Taking such actions can also mitigate some – but not all – FCM PI financial risk, since performance is determined in part by factors that are beyond the resource's control (e.g., factors that affect energy market offers, such as heat rates and non-fuel operating costs).

Fifth, ISO has proposed "stop loss" provisions as part of the FCM PI design. The stop loss mechanism limits a capacity supplier's exposure to financial losses by capping monthly losses. Stop loss provisions are not designed to eliminate the risk of losses, but to insure against extreme losses. By limiting insurance to more extreme circumstances, the stop loss mechanism maintains performance incentives until monthly losses become particularly large. Under the current proposal, the stop loss mechanism limits losses to individual resources at the difference between the FCA starting price ($15 per kW-month) and the FCA clearing price. For example, if the FCA clearing price was $4 per kW-month, then monthly losses for each resources would be capped at the resource's CSO times $11 per kW-month (i.e., $15 minus $4 per kW-month).

Finally, energy and ancillary service market prices tend to increase during reserve shortages that occur during peak (summer) conditions, which are likely to prevail during future reserve shortages under equilibrium conditions. Figure 4 reports the percentage difference between energy market prices on days with peak period reserve shortages against energy prices on comparable days (i.e., either days in the same month or the same week). Day-ahead prices increase by 26% (within week comparison) or 64% (within month comparison) during on-peak periods, and 7% or 21% during off-peak periods. On-peak real-time price increases are larger than on-peak day-ahead prices (151% for the within week comparisons and 100% for the within month comparisons), although market participant revenues are typically most dependent on day-ahead prices.

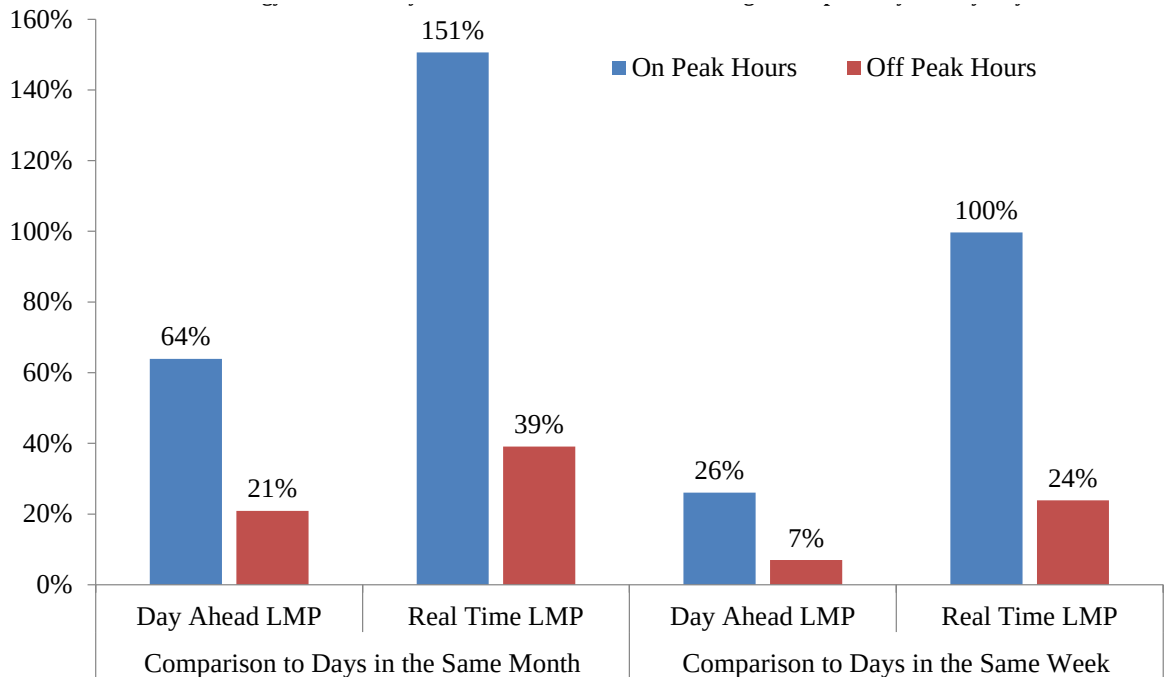
Given the uncertainty introduced by FCM PI in the FCM market, a risk factor is included in resource offers to reflect the resulting financial risk. In practice, the approach taken by individual market participants to estimate a risk factor to include in their offers will reflect many company-specific factors, including information that is often not publicly available. Given these information limitations and the complexities of performing company-level risk assessments for all entities in the ISO-NE market, certain simplifying assumptions are made.

In choosing an analytical approach for estimating the risk factor, it is important to keep in mind that economics and finance provide guidance on alternative ways of measuring financial risk, but do not conclude that there is a single optimal way to measure and manage financial risk. The analysis builds off the Value at Risk approach,[34] which is a standard approach used in the financial sector for valuing the

[34] Eydeland, Alexander, and Krzystof Wolyniec, *Energy and Power Risk Management, New Developments in Modeling, Pricing, and Hedging*, Wiley Finance: Hoboken, New Jersey. Berry, Romain, "Value at Risk: An Overview of Analytical VAR," J.P. Morgan Investment Analytics and Consulting.

financial risk associated with a portfolio of assets.[35] Under this approach, analytical models are used to measure the distribution of potential financial returns of a portfolio of assets. The Value at Risk (VaR) is then the maximum potential loss of the portfolio at a pre-specified confidence level. For example, a firm may estimate that the VaR for a given portfolio of assets is a loss of $2 million at the 5% level over the next month. This means that there is a 5% chance that this portfolio will lead to losses of $2 million or more. Given this information, the firm may adjust its portfolio to bring the risk within (potentially pre-determined) tolerance levels.

Figure 4: Average LMP Increase on Days with Peak Period Reserve Shortages



Note: Figures reflect only reserve shortage events that occurred during peak hours in June, July, or August 2010 - 2012.

Risk factors are calculated using the VaR approach in the following manner. For each resource, the risk factor equals the increase in a resource's offer needed to ensure, with a 95% probability, that it earns positive expected net revenues across all ISO-NE markets. The analysis only considers uncertainty in the level of reserve shortages, but not resource performance. Uncertainty over the level of reserve shortages creates meaningful financial risk, particularly for resources with poor performance. For poorly performing resources, each additional reserve shortage can result in financial losses because the unit's

[35] Other approaches to addressing financial risk include asymmetric (and potentially non-linear) valuation of losses and gains and requiring risk-adjusted returns (potentially reflecting the variance of potential losses). These models are grounded in certain fundamentals of financial analysis (including portfolio theory) but recognize certain costs to losses that may not be recognized in these models, including credit constraints (which may impose limits on the ability of a firm with poor credit from pursuing profitable business opportunities) and managerial risk aversion (which may be a fact of life given principal agent problems).

output is likely below the balancing ratio benchmark. Consequently, if the level of reserve shortages exceeds expectations, losses could grow large, even potentially leading to negative net FCM revenues.[36] By contrast, risks associated with resource performance are bounded by several factors. First, as shown in Figure 1, resource performance and the balancing ratio tend to be positively correlated. Thus, an element of performance uncertainty is addressed by the FCM PI design, which lowers the benchmark against which each resource's performance is compared during shortages when aggregate output is lower. Second, assuming actual reserve shortages equal expected levels, the minimum offer (essentially) provides sufficient revenue to avoid losses (negative net revenues).[37] Analysis that simultaneously considers uncertainty in both reserve shortage levels and operational performance was beyond the scope of our analysis.[38]

Based on uncertainty in reserve shortage levels, the risk factor is calculated as:

$$RF = \min\left\{0, GFC - P_{FCM} - PPR * H_{95\%} * \left(A - BR\right)\right\}$$

Here, $H_{95\%}$ is the reserve shortage level at the 95% confidence interval. This value is based on the probability distribution of future reserve shortages under different levels of excess resources from analysis performed with the ISO-NE system model. In effect, as shown in Figure 5, the risk factor shifts the distribution of total returns such that there is a 95% likelihood that the resource has positive net returns.

These VaR estimates reflect one approach to estimating resource risk factors, but may not consider all factors relevant to determining the risk factor for individual resources. For many resources, these risk factors will reflect conservative estimates of risk. For poor performing resources, the approach can result in tradeoffs between risk and expected returns suggesting that market participants are very risk averse.[39] On the other hand, for some market participants, the VaR approach may understate risk factors by assuming that they would be indifferent to the choice between a market position with and without a CSO that provides equal expected returns. It is quite likely that some market participants faced with these

[36] Even when actual performance equals the resource's expected performance, actual FCM revenues will be negative whenever the number of reserve shortage hours is greater than the ratio of the annual fixed FCM revenues (i.e., P_{FCM}) divided by the loss per hour of reserve shortage – that is: $H > \frac{P_{FCM}}{PPR * \left(BR - A\right)}$.

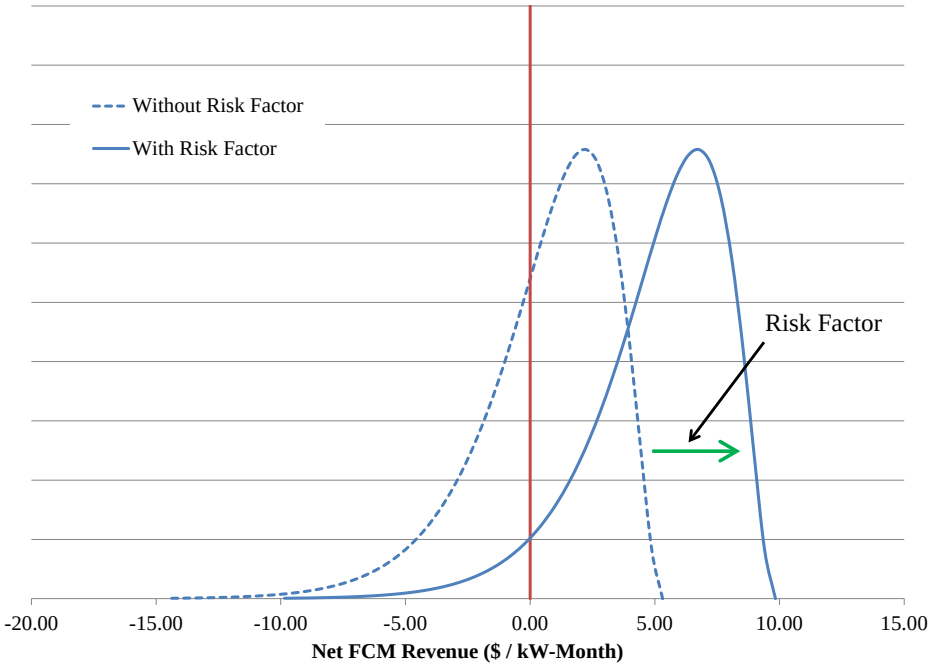
[37] With no uncertainty over *H*, the minimum offer is *PPR*H*BR*. So long as actual *BR* is no less than the expected *BR*, then the minimum offer exceeds the revenue adjustments for all levels of output. That is, $PPR * H * E\left[BR\right] + PPR * H * \left(A - BR\right) \geq 0$ for all levels of performance *A* as long as the actual average balancing ratio (*BR*) is less than the expected average balancing ratio (*E* [*BR*]).

[38] Such analysis would require Monte Carlo analysis that accounted for both reserve shortage and performance uncertainty, along with the relationship (correlation) between these factors, which would vary across individual resources.

[39] For example, consider a poorly performing resource (A = 0.1) with going forward cost of $1 per kW-month under the following market conditions: BR = 0.75, E[hours] = 12, $\text{Hours}_{95\%}$ = 25.2. This resource would have a risk factor equal to $3.57 per kW-month. A risk factor at this level suggests that the resource would prefer to forego a CSO and receive expected FCM revenues of $0.50 per kW-month from providing capacity without an obligation (reflecting performance incentive payments) rather than accept the CSO with expected returns of $4.57 per kW-month. This sort of tradeoff suggests a high degree of risk aversion on the margin.

two choices would require some risk premium to accept the financial option (contingent on the balancing ratio adjustments) that comes with a CSO under FCM PI. This type of preference is consistent with behavioral economics, managerial incentives, and certain corporate finance limits.[40] In practice the value of the FCM PI option will depend on each market participant's individual risk profile. Thus, our approach likely understates the quantity of resources that would opt to submit positive risk factors.

Figure 5: Illustrative Depiction of the Shift in Net Revenues with the Risk Factor



Risk factors also account for portfolio effects among resources owned by the same corporate entity. By considering these portfolio effects, the risk factor estimates account for hedging of risk across individual resources. For example, an entity with one high performing resource (typically receiving positive FCM revenues with every incremental reserve shortage) and one poor performing resource (typically receiving negative FCM revenues with every incremental reserve shortage) would face very different financial risks than an entity with only one poorly performing resource. To account for these portfolio effects, each resource's risk factor reflects the portfolio of resources that would clear if it were the marginal resource. Thus, for each resource, the risk factor reflects the marginal risk it adds to the portfolio of resources that would clear at or below its offer price.

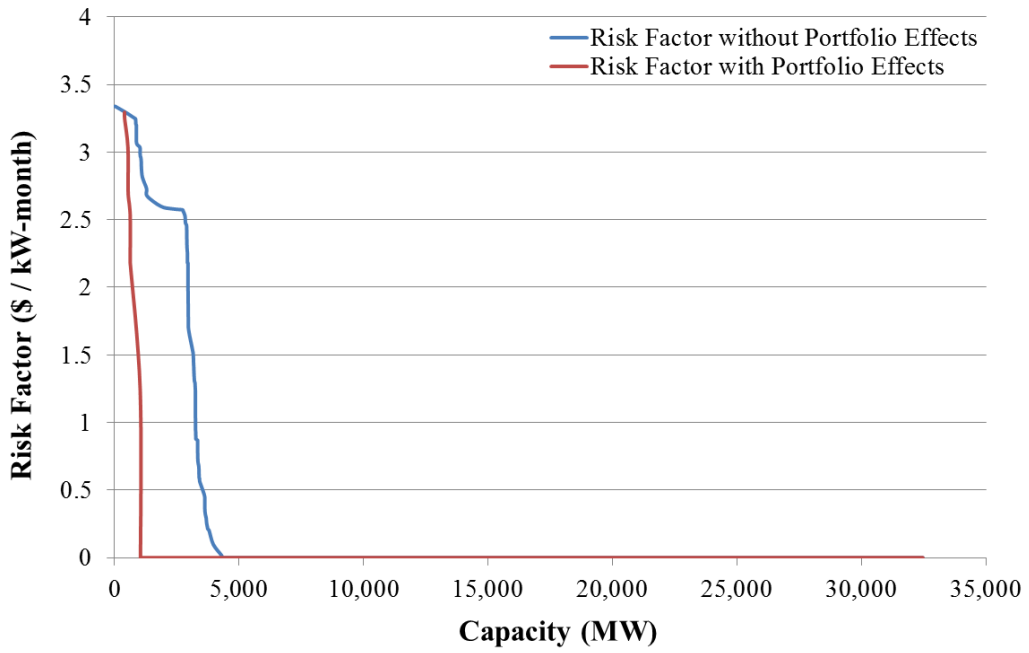
Because this approach accounts for only a limited set of factors, it may understate risks for some resources and overstate them for others. On the one hand, the analysis does not account for factors that would mitigate risks, including stop loss provisions and opportunities to hedge financial risks. On the

[40] For example, greater uncertainty can increase the risk that a firm faces circumstances in which it is credit constrained and potentially must forgo potentially profitable investments.

other hand, the analysis does not account for factors that would increase risk, including performance uncertainty and behavioral preference for more certain returns.

The resulting risk factors vary across scenarios. Figure 6 shows the risk factors for the Equilibrium: No Gas scenario. Without portfolio effects, about 4,300 MW of resources have positive risk factors, with the largest risk factor at nearly $3.50 per kW-month. Resources with positive risk factors include units with relatively low performance (below 40%) and some higher performing resources that rely on FCM revenues to remain economically viable (i.e., resources with positive GFC including FCM PI revenues). Financial risks are greater for resources with higher going forward costs because they have less financial cushion from other ISO-NE markets to ensure positive profitability. Accounting for portfolio effects reduces the quantity of resources with risk factors to about 1,000 MW, with a minimal change in the largest risk factor. After accounting for portfolio effects, resources with positive risk factors include those resources held by entities with few resources and some poorly performing units with high going forward costs held by entities with larger portfolios.

Figure 6: Risk Factors in Near-Term Equilibrium Scenario



VI. IMPACT OF PERFORMANCE INCENTIVES ON ISO-NE MARKET

A. Impact on Reliability

In principle, FCM PI has the potential to improve reliability through several mechanisms, including increases in the supply of resources in the ISO-NE energy markets, increased adoption of dual fuel capability, changes in the mix of resources toward higher performing resources, and improvements in the operational performance through changes in operating practices or other performance investments (e.g., ramping capability). The analysis quantifies many but not all of these impacts.

1. Increase in Resource Supply

The introduction of FCM PI can affect the quantity of resources that continue to participate in the ISO-NE energy market. As described in Section IV.A, if the expected level of reserve shortages is sufficiently high, then some resources that do not take on an FCM CSO may remain in ISO-NE's energy market in anticipation of additional FCM PI payments received for output supplied during reserve shortages. Under these circumstances, the quantity of resources in the ISO-NE energy markets can exceed ICR, which, in turn, results in improved reliability, including reductions in the level of reserve shortages.

Table 4 reports estimates of the difference between the total quantity of "economic capacity" and ICR, referred to as "surplus capacity." Surplus capacity includes all capacity with a CSO and any surplus capacity resources without a CSO that receive sufficient revenues to remain economically viable in the ISO-NE energy markets. Determination of which resources are economically viable (i.e., receive positive net revenues including all ISO-NE markets) reflects only the costs identified in Section V, but may not capture all relevant values affecting resource retirement decisions.[41] Under current market rules, the analysis finds that there is no surplus economic capacity – that is, at the clearing FCA price, only those resources receiving a CSO will find it economically profitable to remain in the market.

Table 4: Market and System Outcomes under Historical and Equilibrium Scenarios

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$1.93	$2.55	$2.91	$3.76	$3.76	$4.49
Total FCM Payments ($bil)	$0.54	$0.80	$1.06	$1.20	$1.56	$1.56	$1.86
Avg FCM Payments ($/MWh)	$4.07	$5.99	$7.92	$9.01	$11.68	$11.66	$13.92
% Change Relative to 2012 Level	-57%	-36%	-15%	-4%	25%	25%	49%
New Entry Offers ($/kW-month)	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Surplus Capacity Above ICR (MW)	0	0	0	0	1,036	1,390	1,472
Expected Reserve Shortage Hours	21	-	-	-	9.00	10.00	12.75
Summer Peak RS Hours	21	-	-	-	9.00	7.00	6.75
Winter Gas-Related RS Hours	-	-	-	-	0.00	3.00	6.00
Incremental Dual Fuel Capacity (MW)	0	226	5,848	7,368	39	6,130	7,988

Note: For the Historical Scenario, Expected Reserve Shortage Hours are not reported as they do not reflect a consistent market-system equilibrium.

Under Historical system conditions, there is no surplus capacity as a consequence of FCM PI. Given the level of reserve shortages assumed in these Historical scenarios, incremental FCM PI revenues are insufficient to keep resources in excess of the ICR in the energy markets.

[41] Values not considered in our analysis include significant investments needed to maintain on-going operations and the option value to delay retirements given that revenue streams in future years could be sufficient to allow plant operation to be economically profitable.

In the near-term Equilibrium scenarios, surplus capacity ranges from 1,036 MW with no gas shortages to 1,472 MW with gas shortages (Equilibrium: High Gas). In these cases, more than 1 GW of resources in excess of the ICR would find it financially profitable to remain in operation in the energy markets, even without a CSO.

Table 4 also reports the expected number of reserve shortage hours given the level of surplus capacity in each scenario based on results from the ISO-NE system model. For the Equilibrium scenarios, there are 9.0 reserve shortages hours with no gas shortages, 10.0 total hours with gas shortages (3 hours) and 12.75 total hours with high has shortages (6 hours). These values equal the level of reserve shortages estimated when determining the market-system equilibrium based on the level of *summer peak* reserve shortages (as described in Section V.C). As higher levels of winter gas reserve shortages are assumed, the equilibrium level of total reserve shortages increases, which provides additional revenues for a larger quantity of surplus capacity. This higher level of surplus resources, then results in a lower level of *summer peak* reserve shortages. Thus, the level of summer peak reserve shortages declines as additional winter gas reserve shortages are assumed.

For the Historical scenarios, the values are not reported as they do not reflect a consistent market-system equilibrium.[42] Outcomes without FCM PI reflect the fact that under the current FCM model, the "economic" supply of resources equals ICR – that is, excess supply equals zero.[43] Thus, the expected level of reserve shortages is higher – 21 hours – because there is no surplus capacity. This outcome also corresponds to the long-term equilibrium in which new resources are needed to help meet future growth in ICR.

These results indicate that FCM PI would likely result in higher levels of reliability by increasing the quantity of resources participating in the ISO-NE markets. The improvements in reliability from this surplus capacity are reflected in the differences in the level of reserve shortages between the current FCM model (21 hours) and the Equilibrium scenario outcomes (9.0 to 12.75 hours). These reliability benefits would be experienced throughout the year, although they would be the most significant during summer peak load periods. Reliability risks associated with winter gas limitations would also benefit, to the extent that the surplus reflects resources that are not "gas dependent." Later sections address these factors in greater detail.

Our analysis considers resource outcomes for the 2018/2019 Commitment Period, but does not quantitatively assess outcomes in subsequent commitment periods. Thus, the length of time that surplus capacity remains under FCM PI is not estimated, although FCM PI could extend the period with surplus capacity under many plausible market outcomes. Thus, the reliability benefit of FCM PI found for the 2018/2019 Commitment Period could be further extended.

Eventually, as operating and investment costs for existing resources increase (or operating performance decreases), resources that are currently economically viable under FCM PI will retire. As

[42] That is, the market model assumes one level of reserve shortages but the resulting level of surplus capacity produces a different level of reserve shortages in the system model.

[43] In reality, some resources may continue to operate in the market due to variety of factors, including the option value to continuing operation in future years in anticipation of increases in future capacity or energy market prices. This suggests that, when accounting for these factors and option values, the quantity of resources with negative GFC costs (i.e., resources that require positive FCM revenues to remain financially viable) could exceed the ICR.

this occurs, the current surplus of capacity will diminish, leaving the region in need of new generation resources. However, while the long-run equilibrium under the current FCM rules tends toward a system in which the quantity of resources equals the ICR, under FCM PI, the incremental revenues (which can economically support existing resources and reduce offers from new entry, as discussed below) could result in a long-run with resources in excess of the ICR. At this point in time, FCM PI should be expected to provide the same or greater level of reliability, based on the 1-in-10 days loss of load expectation criterion used in setting the ICR.

2. Actions to Improve Performance, including Adoption of Dual Fuel

The opportunity to earn additional revenues during reserve shortages creates an incentive for resources to take actions to improve performance. Improved performance can be achieved through new investments (e.g., adding dual fuel capability, improving generation performance and lowering startup costs) and operational changes (e.g., improved maintenance to limit forced outages, increased pumping by pumped storage units, and improved systems to respond to system operator dispatch requests). To the extent that such actions are undertaken, they could result in improved reliability (including reductions in the level of reserve shortages), lower energy market costs and lower FCM prices.

The quantitative analysis assesses the extent to which resources that could face limited access to fuel supplies – gas-dependent resources – take steps to make their plants capable of burning an alternative fuel. With dual fuel capability these resources, which otherwise might lose revenues due to curtailed fuel supply, can continue operations during reserve shortages.

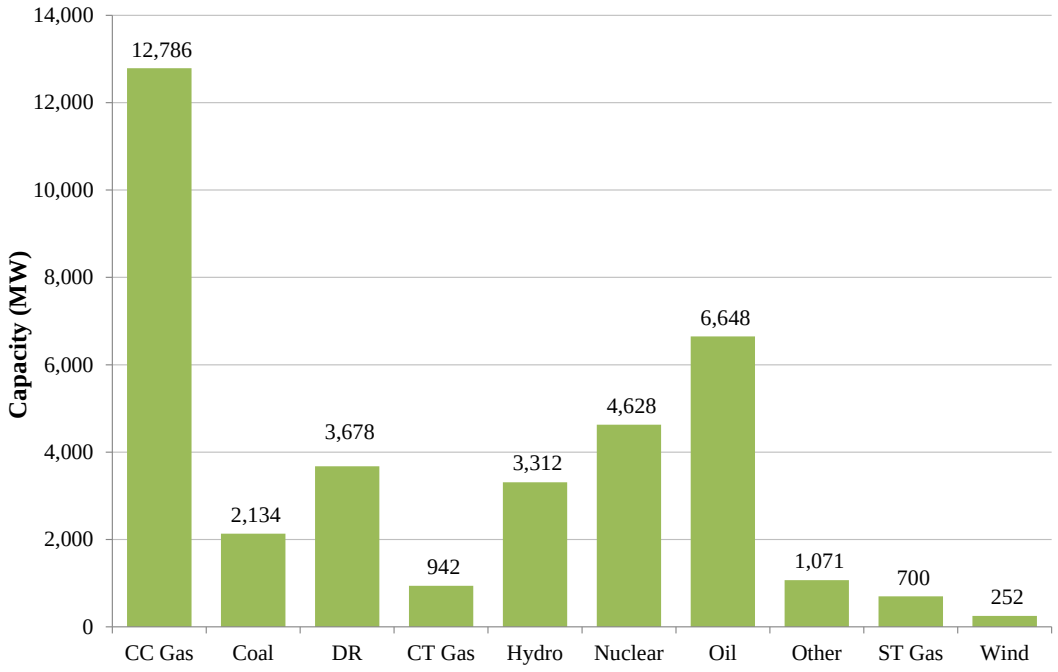
Figure 7 illustrates the mix of resources in the current ISO-NE fleet. Roughly 30% of the region's generation resources, or 10.1 GW out of 36.1 GW, are currently dependent solely on natural gas, with no option to operate on an alternative fuel. Today, roughly 6,600 MW of capacity has dual fuel capability, although this total has fallen from higher levels in recent years because the divergence of gas and oil prices has made oil combustion uneconomic.[44] As current market conditions do not support maintaining dual fuel capability (including maintenance of alternative fuel capabilities and storage of costly fuel supplies) for energy production, and there are currently no mechanisms for supporting dual fuel capability for reliability purposes, the supply of dual fuel capability has diminished over time.

The analysis indicates that the introduction of FCM PI would increase the supply of resources that are not subject to gas-dependency. Figure 8 illustrates these changes by highlighting both the quantity of dual fuel capability and the quantity of non-gas resources (which do not face gas curtailment risks) with and without FCM PI, under the Equilibrium scenarios. FCM PI would increase investment in dual fuel capability under conditions when market participants expect reserve shortages driven by limited gas fuel supplies. Without PI, there is 5,607 MW of dual fuel capability in the region. Under Equilibrium scenarios, dual fuel capability increases by 6,130 MW to 11,737 MW if 3 hours of winter gas shortages are assumed, and by 7,988 MW to 13,595 MW if 6 hours of winter gas shortages are assumed. Results are similar under the Historical scenarios, as shown in Figure 9. There is also a small increase in dual fuel capability (226 MW under Historical conditions and 39 MW under Equilibrium conditions) when no

[44] This total includes some resources that, in a past, tended to operate primary on non-gas fuels (primarily oil) that have switched largely to gas-fired operations in recent years.

winter gas shortages are expected because of shifts in the mix of "economic" resources with and without FCM PI.

Figure 7: Current ISO-NE Resource Mix (FCA 7)



Note: The figure lists only resources within the ISO-NE footprint, thus excluding imports that clear in FCA7.

These comparisons reflect the assumption that all existing dual fuel resources retain this capability under current market rules. Thus, our analysis does not account for the risk that owners of facilities with dual fuel capability opt to mothball this capability, as many resources have already done in recent years. By assuming that resources preserve dual fuel capability absent FCM PI, the analysis may understate FCM PI reliability benefits by failing to capture these potential losses of dual fuel capability. The analysis also assumes that the addition of dual fuel capability is the least-cost approach to mitigating gas curtailment risks, as discussed in Section V.D. To the extent that there other options that can provide this mitigation at lower cost, then the analysis would also tend to understate the reliability benefits of FCM PI.

In addition to these increases in dual fuel capability, FCM PI results in small increases in the quantity of non-gas resources that help maintain reliability in periods of limited gas supply. Without FCM PI, there are 19,304 MW of non-gas resources in the Equilibrium scenarios. With the introduction of FCM PI in the Equilibrium scenarios, the quantity of non-gas resources increases to 19,803 MW, without assuming any winter gas reserve shortages. When winter gas reserve shortages are assumed, the quantity of non-gas resources increases by another 452 MW with 3 winter gas reserve shortage hours and 534 MW with 6 hours.

Figure 8: Gas Dependency Resource Changes, Equilibrium Scenarios

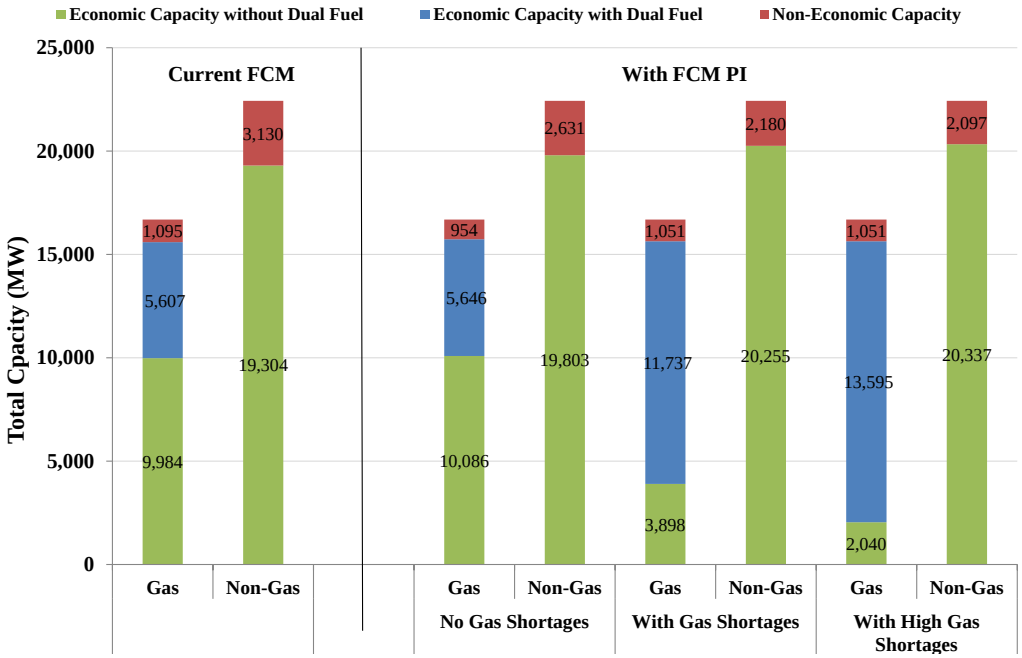
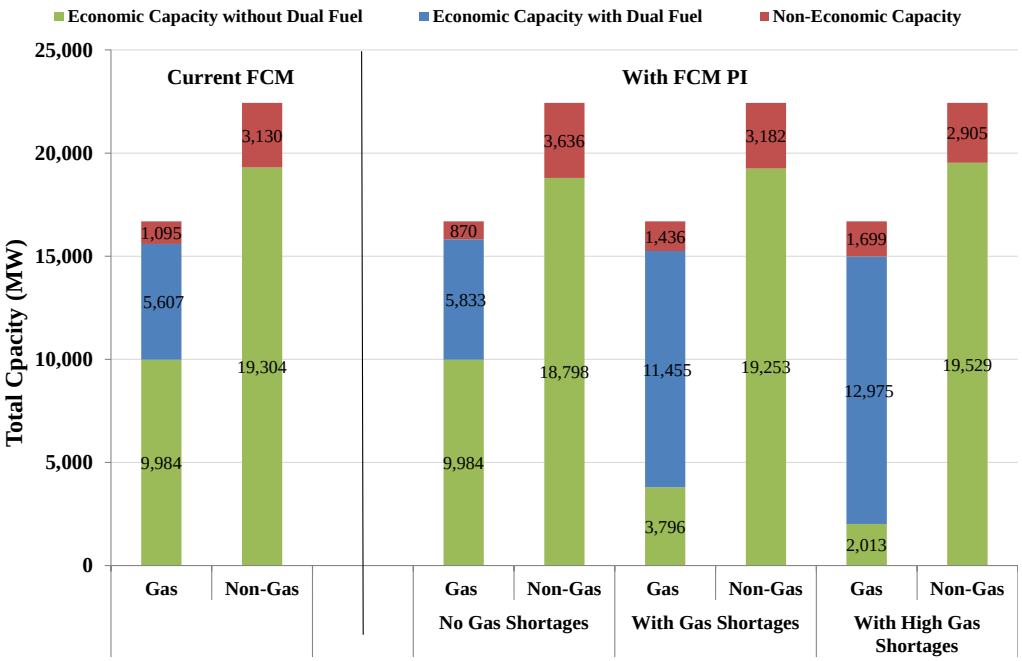


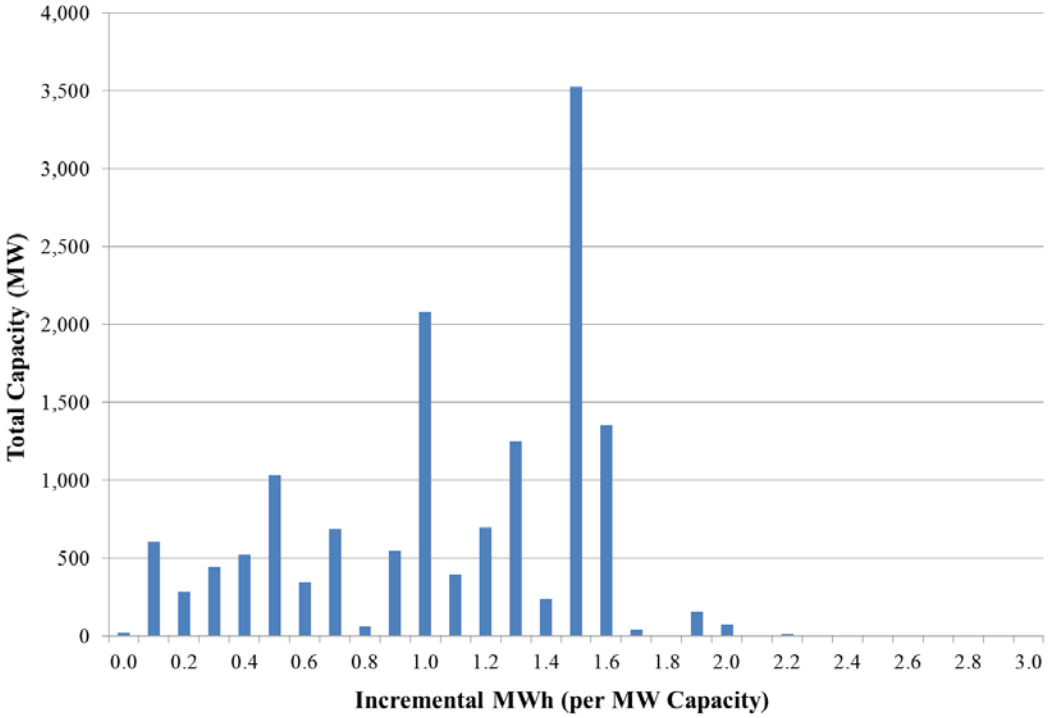
Figure 9: Gas Dependency Resource Changes, Historical Scenarios



Notes for Figures 8 and 9:
[1] Dual Fuel Gas Capacity includes some units listed in the 2013 CELT Report with a primary fuel type of RFO or DFO that currently have dual fuel capability.
[2] Oil units based on primary fuel use from 2013 CELT Report, but may include units that have used gas as a primary fuel in recent years.

For each gas-dependent resource, the financial gains from adopting dual fuel capability reflect the incremental MWh of output that can be supplied during winter reserve shortages from having addressed the unit's gas curtailment risks. Figure 10 illustrates the distribution of operational benefit of maintaining dual fuel capability for all gas-fired resources, as reflected by the incremental MWh supplied during winter gas reserve shortages, for the Equilibrium: Gas scenario (i.e., 3 hours of reserve shortages). For example, consider a 100 MW resource with "Incremental MWh per MW of Capacity" equal to 1.6 MWh over the three hours of additional winter reserve shortages. This unit would receive an additional 160 MWh of output by investing in dual fuel capacity; over one year, assuming a PPR of $5,455, this resource would receive an additional $872,800 in revenues. The figure shows that even though there are 3 additional hours of reserve shortages, our approach results in relatively modest assumptions about the additional MWh of output that market participants would gain from investing in dual fuel.

Figure 10: Distribution of Incremental MWh (per MW of Capacity) during Winter Reserve Shortages, Gas Shortage Scenario (3 Hours)



These results are particularly sensitive to assumptions about cost. As shown in Figure 3, portions of the dual fuel supply curve are relatively flat, which could lead to large variation in the quantity of dual fuel upgrades depending on the magnitude of performance incentives. To determine whether this affects estimated outcomes, a sensitivity analysis is performed in which dual fuel costs (including both upfront capital and annual expenditures) are increased by 25%. The results of this scenario are reported in Table 5. When costs are increased by 25%, the quantity of dual fuel upgrades increases under FCM PI by 2,985 MW with 3 hours of gas shortages, and by 7,484 with 6 hours of gas shortages. Thus, dual fuel upgrades from FCM PI decrease by over 50% when costs are increased by 25% with 3 hours of winter reserve shortages. By contrast, dual fuel upgrades decrease by only 6% at the higher level of winter reserve shortages (6 hours). These results suggest that there is substantial uncertainty about the level of dual fuel

upgrades at moderate levels of gas dependency risks, but less uncertainty when these risks become sufficiently high.

Table 5: Market Outcomes for Dual Fuel Cost Sensitivity Analysis

		Baseline Costs		Baseline Costs + 25%	
	Current Rules (No FCM PI)	FCM PI Gas Shortages	FCM PI High Gas Shortages	FCM PI Gas Shortages	FCM PI High Gas Shortages
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$4.49	$3.76	$4.49
Total Dual Fuel Capacity (MW)	5,607	11,737	13,595	8,592	13,091
Change in Capacity from No FCM PI	-	6,130	7,988	2,985	7,484

The results indicate that FCM PI can increase reliability by improving the quality of resources participating in ISO-NE markets. The analysis shows that resources that would otherwise face no incentive to develop dual fuel capability would choose to develop this capability under FCM PI when market participants anticipate meaningful system reliability risks associated with gas-supply curtailment. However, the analysis does not identify a final equilibrium between the quantity of dual fuel upgrades and the level of reliability (as reflected in reserve shortages) given gas dependency risks. As with the equilibrium between the level of total system resources and summer peak reliability, this eventual equilibrium will depend on the dynamic between these two factors. As the quantity of dual fuel upgrades increases, reliability risks associated with gas-dependency will improve; however, as winter gas reliability improves (and reduces the level of reserve shortages), revenues to support dual fuel upgrades will decrease. Thus, the analysis does not resolve uncertainty about the final level dual fuel upgrades and winter gas reliability under FCM PI.

The quantity of incremental dual fuel capability developed rises as high as 7,988 MW under the "worst case" expectations evaluated (i.e., 6 hours of winter gas reserve shortages under Equilibrium conditions). Because all but roughly 2 GW of gas-fired resources would upgrade to dual fuel under this scenario, the underlying reliability risks driving these winter gas reserve shortages would likely be fully mitigated. This suggests that an "equilibrium" level of gas reserve shortages and additional new dual fuel capability could be below the levels assumed in this "worst case" scenario. This conclusion is further supported by the fact that FCM PI would provide additional incentives for resources relying on on-site fuel supplies (particularly oil-fired resources and existing dual fuel resources) to maintain higher levels of on-site stored fuel, which could mitigate reliability risks associated with prolonged and sequential episodes of gas supply limitations.

While the results of this "worst case" scenario suggest that FCM PI would provide sufficient incentives to mitigate gas dependency risks, the analysis does not identify a precise equilibrium level of dual fuel upgrades and winter gas reliability. Moreover, the sensitivity of the quantity of dual fuel upgrades to assumptions about underlying upgrade costs highlights the substantial uncertainty about the eventual equilibrium levels of incremental actions taken to mitigate winter gas curtailment risks

(including dual fuel) and winter gas reliability (as reflected in reserve shortage hours) when winter gas dependency risks are at levels more moderate than the "worst case" scenario.[45]

3. Change in Mix of Economic Resources in ISO-NE Markets

The introduction of FCM PI is intended to create incentives for higher performing resources to compete more effectively against lower performing units. With these incentives, resource entry (new build) and exit (retirement) decisions should result in a mix of higher performing resources in the long run as these retirement and new build decisions are made. The analysis of outcomes in FCA 9 and impacts on the cost of new entry can provide insights on the extent to which these incentives have meaningful effects on these decisions.

The introduction of FCM PI has several effects on the mix of available resources. These effects are illustrated in Table 6, which reports the mix of "economic" resources with and without FCM PI under the Equilibrium: No Gas Scenario, as well as Figure 11, which shows "non-economic" capacity by resource type for the Equilibrium: No Gas and Historical: No Gas scenarios. As discussed above in Section VI.A.1, the total quantity of economic resources is expected to be greater under FCM PI than under current FCM rules. Despite this aggregate increase, the quantity of oil-fired resources decreases with FCM PI. Figure 11 shows that the quantity of "non-economic" oil-fired capacity increases from 1,047 MW to 2,282 MW in the Equilibrium: No Gas scenario, suggesting an increased likelihood of retirement of oil-fired resources under FCM PI. By contrast, the quantity of all other resource types increases under FCM PI compared to current rules. Demand response and imports (combined) increase by 1,407 MW in the Equilibrium: No Gas scenario, while there is combined increase of 476 MW between gas-fired resources (CC Gas, CT and ST Gas) and coal-fired resources. These changes to the resource mix are generally supportive of reliability, as they result in a larger supply of more flexible resources, including fast start and demand response, and a reduced supply of slower fossil units, such as oil units.

As seen in Table 6, performance varies across resource categories, and the average performance masks variation among the units within individual categories. Variation in performance reflects operational factors (e.g., forced outages) and economic factors (e.g., heat rates, start-up costs and other factors that affect resource energy market offers). For existing resources, market participants have some control over these factors and limited control over others.

Table 6 also illustrates that under FCM PI, resource performance (as measured by average performance *A*) tends to increase for certain generator categories compared to current rules. These shifts in performance reflect two offsetting factors. The first arises from the fact that more economic resources remain in the market with FCM PI than without. Because marginal resources will tend to have poorer performance than resources that remain in the market, under any scenario, the *average* performance will tend to decrease as the quantity of surplus resources increases simply because the last resources added tend to have lower performance. This effect would tend to result in *lower* average performance under FCM PI, because it supports a larger pool of resources.

[45] This sensitivity mirrors the uncertainty underlying other assumptions, including the level of gas curtailment risk that resources would face during winter gas-related reserve shortage, which was set at a 50% reduction in output without dual fuel capability to balance the range of curtailments that resources could face.

Table 6: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,698	112%	7	4%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	91%	74	22%
Coal	1,703	86%	431	90%
CT or ST Gas	1,642	89%	0	NA
Oil	4,366	66%	2,282	14%
Other	1,070	91%	0	15%
Total	35,536		3,585	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	112%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	92%	315	70%
Coal	1,591	85%	543	93%
CT or ST Gas	1,520	89%	122	91%
Oil	5,601	54%	1,047	39%
Other	1,071	91%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

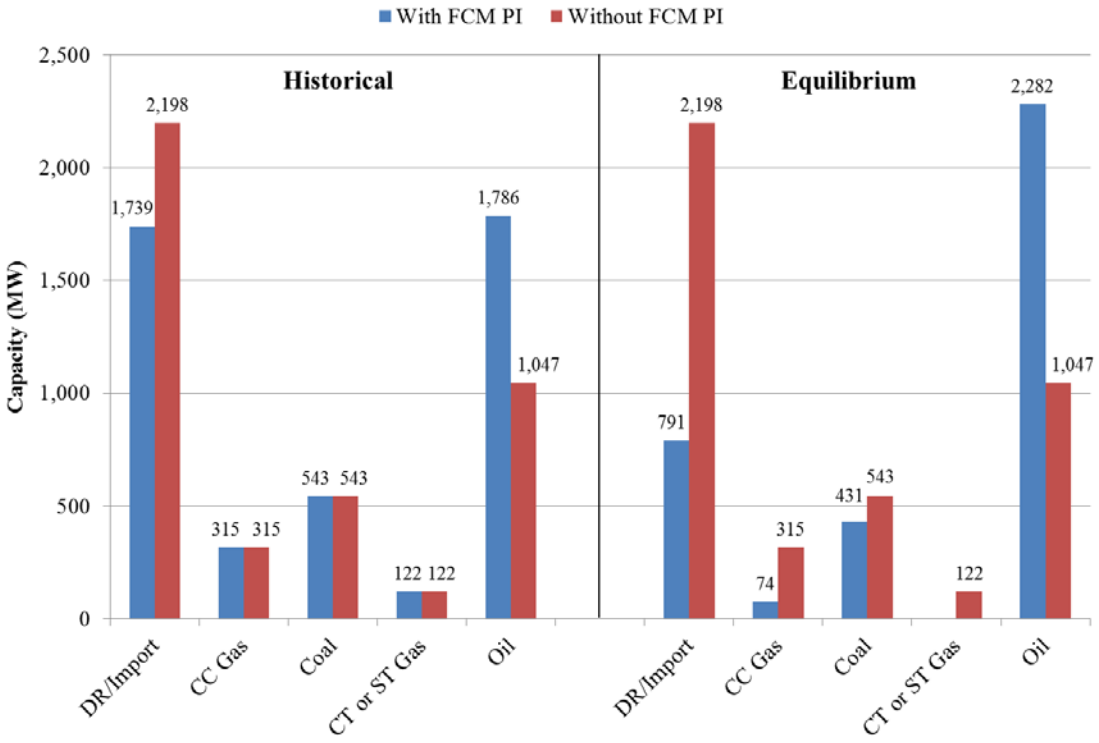
	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	-7	0.2%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.1%	-241	-48%
Coal	113	1.3%	-113	-3%
CT or ST Gas	122	0.1%	-122	NA
Oil	-1,235	12%	1,235	-25%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

However, FCM PI also results in shifts among resources that are economic, with higher performing resources clearing due to PI, and lower performing resources becoming non-economic. This effect would tend to result in higher average performance with FCM PI.

As shown in Table 6, the effect of FCM PI on average performance tends to outweigh the effect of the higher quantity of resources, suggesting that these incentives would likely have a positive effect on improving the average performance of resources in the region. For all resource categories but CC Gas, average performance increases with FCM PI. The improvement in performance is most notable with oil-fired resources, which have performance of 66% with FCM PI and 54% without FCM PI.

Figure 11: Non-Economic Capacity by Technology/Fuel Type with and without PI, Historical and Equilibrium (No Gas) Scenarios



Changes to the resource mix introduced by FCM PI under the Historical: No Gas scenario have similar effects to those for the Equilibrium: No Gas scenario, as shown in Figure 11. Under the Historical scenario, there is no surplus economic capacity because the level of FCM PI revenues is reduced with the lower level of expected reserve shortages.[46] Non-economic capacity is higher in the Historical scenario for all resource types except oil-fired capacity. Under historical conditions, there are fewer non-economic

[46] The small quantity of capacity in excess of the ICR in the Historical scenarios and the scenario with no FCM PI arises because only a fraction of the marginal resource is required to meet the ICR. Because our model assumes that a portion of a unit cannot retire, the remaining fraction of the marginal resource is assumed to remain in the market.

oil-fired resources because the performance incentive payments are lower, which in turn reduces the competitive disadvantage that the oil-fired resources with lower performance experience under FCM PI.

Detailed tables for other scenarios are provided in Appendix B, which illustrates the change in resource mix when there are winter gas reserve shortages. As the level of winter reserve shortages increases, the changes in the resource mix introduced by FCM PI tend to be similar across scenarios, although the quantity of non-economic oil-fired resources increases with high gas-related reserve shortages. Although a higher level of winter gas reserve shortages could create financial risks for gas-dependent resources, the ability to develop dual fuel capability provides these resources with an option to mitigate this financial risk to maintain economic operations. Thus, the quantity of economic gas-fired capacity remains unchanged as the level of winter gas reserve shortages increases.

Our analysis does not account for actions resources can take to improve operating performance aside from the opportunity for gas-dependent resources to invest in dual fuel capability. These potential actions range from investments to improve operating efficiency (e.g., heat rates) and ramp rates to improved management and maintenance to reduce forced outages.

The results indicate that FCM PI can improve reliability through shifts in the mix of resources toward more flexible types and toward higher performing resources within individual resource categories. While the analysis captures these changes in performance, it does not provide any information on the technical or operational factors that lead to varying average performance across units in the ISO-NE fleet, or the factors that tend to affect the ability of resources to operate profitably in the ISO-NE markets.

B. Impact on Costs

FCM PI has several potential impacts on costs. In principle, FCM PI can lower production costs if shifts in the mix of resources results in a fleet of resources with higher operating efficiencies (e.g., lower heat rates). Statistical analysis indicates that there is typically a correlation between higher performing resources and more efficient resources, which suggests that FCM PI could contribute to increasing the operating efficiencies of resources in the region's fleet.[47]

FCM PI will also result in additional expenditures, as resources take additional steps to improve performance. As gas-dependent resources invest in dual fuel capability, they will incur both upfront capital costs and annual operating costs. In the Equilibrium: Gas scenario (3 hours winter reserve shortages), upfront capital investment is about $310 million and incremental annual expenditures are $31 million for 6,130 MW of new dual fuel capability. In the Equilibrium: High Gas scenario (6 hours of winter reserve shortages), upfront capital investment is about $462 million and incremental annual expenditures are $46 million for 7,988 MW of new dual fuel capability. These costs reflect the upward sloping supply curve in Figure 3, which results in higher costs for the additional dual fuel capability added when the level of winter gas reserve shortages increases from 3 to 6 hours.

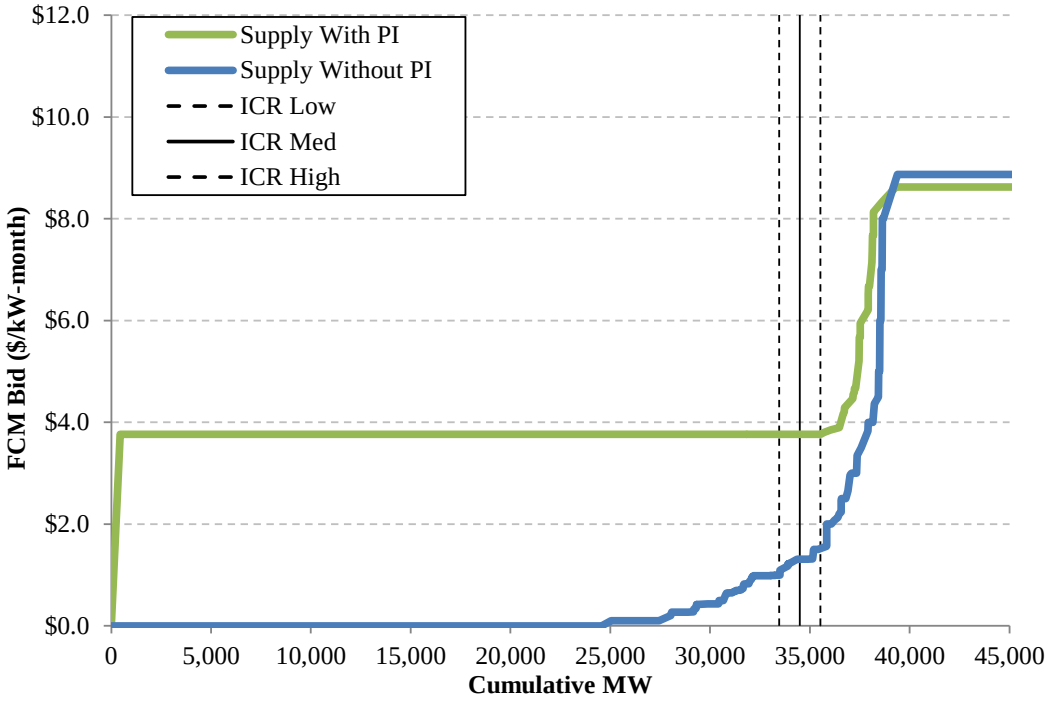
[47] Analysis of the correlation between average performance and heat rate for five resource categories across each of the three types of reserve shortages (historical, peak summer, winter gas) found a negative correlation for 11 of 15 tests, with oil-fired resources showing a positive correlation over all three types of reserve shortages.

Although not an element of our quantitative analysis, FCM PI could delay the date when new generation resources are needed to meet the ICR. Such delays could arise because the additional PI revenues can delay the retirement date for some resources, thus extending the operating lifetime of the region's current resource surplus further into the future.[48] By delaying the date at which new generation resources are required, FCM PI can lower resource costs. Because our analysis quantitatively evaluates outcomes only for 2018/2019, we do not estimate the likelihood that FCM PI delays new investment needed to meet the ICR, the length of such days or the associated cost savings.

C. Impact on Prices and Payments

The introduction of FCM PI will have both direct and indirect effects on many ISO-NE markets, including energy, ancillary services and capacity markets. Figure 12 illustrates the supply of offers from FCM resources with and without FCM PI in the Equilibrium: No Gas scenario. The introduction of FCM PI results in several shifts to the offer curve, including: an upward shift to minimum offers (reflecting the downward FCM PI revenue adjustments for the balancing ratio, $PPR * CSO * BR$), an upward shift in offers from many "marginally economic" units which tend to have relatively poor performance; and a downward shift to the cost of new entry, reflecting performance A greater than the balancing ratio for new resources. At the anticipated ICR of 34,500 MW for 2018/2019, the market clearing prices are $3.76 per kW-month with FCM PI and $1.31 per kW-month without FCM PI.

Figure 12: FCM Offer Curve with and without PI, Near-Term Equilibrium, No Gas Conditions



[48] FCM PI incentives could also induce new resources to enter the market at prices below the cost of new entry under conditions when there is surplus capacity above the ICR.

Table 4 reports the clearing prices for the other scenarios evaluated. Across the six scenarios, the clearing price without FCM PI remains unchanged ($1.31 per kW-month) because variations in the level of reserve shortages have no impact on FCA offers without FCM PI. However, with FCM PI, offers change to reflect anticipated FCM PI revenues. Under Historical scenarios, prices are lower due to the lower level of reserve shortages. This difference is best seen by comparing the scenarios with no gas shortages, with FCA prices at $1.93 per kW-month under historical conditions, and $3.76 per kW-month under near-term equilibrium conditions. Under historical conditions, FCA prices rise with the addition of winter gas reserve shortages hours to $2.55 per kW-month (6.2 total reserve shortage hours) and $2.91 per kW-month (with 9.2 total reserve shortage hours). Under equilibrium conditions, FCA prices vary across scenarios from $3.76 per kW-month to $4.49 per kW-month for the two approaches to modeling the high gas scenario equilibrium.

While FCM PI increases FCA offers for most existing resources, offers from new resources could decrease with the introduction of FCM PI if anticipated performance exceeds the balancing ratio. Whether this occurs, in practice, will depend on project developers' expectations about the performance of proposed projects, given various technological, operational and geographic factors. Moreover, FCM PI is designed to encourage development of those new resources with high performance.

To gauge the potential effect of FCM PI on the FCA offers from new entry, a benchmark group of gas-fired combined cycle and combustion turbine generation facilities recently developed in the ISO-NE region was chosen to represent new resource performance. The average performance of each group of resources was used to estimate the impact of FCM PI on the FCA offers from new entry for each technology. As shown in Table 7, which reports the offers from new combined cycle and combustion turbine technologies, FCM PI would likely reduce FCA offers from new resources below the cost of new entry (CONE) under current market rules, reflecting average performance by the benchmark group that exceeds the average balancing ratio in most cases.[49]

Table 7: Offers from New Entry with and without FCM PI

		FCM PI, Historical Scenario			FCM PI, Near-Term Equilibrium Scenario		
	Current Rules (No FCM PI)	No Gas Shortages	Gas Shortages	High Gas Shortages	No Gas Shortages	Gas Shortages	High Gas Shortages
Combined Cycle	$8.87	$8.67	$8.08	$7.49	$8.62	$8.09	$7.50
Combustion Turbine	$13.42	$13.34	$13.02	$12.70	$13.55	$13.20	$12.88

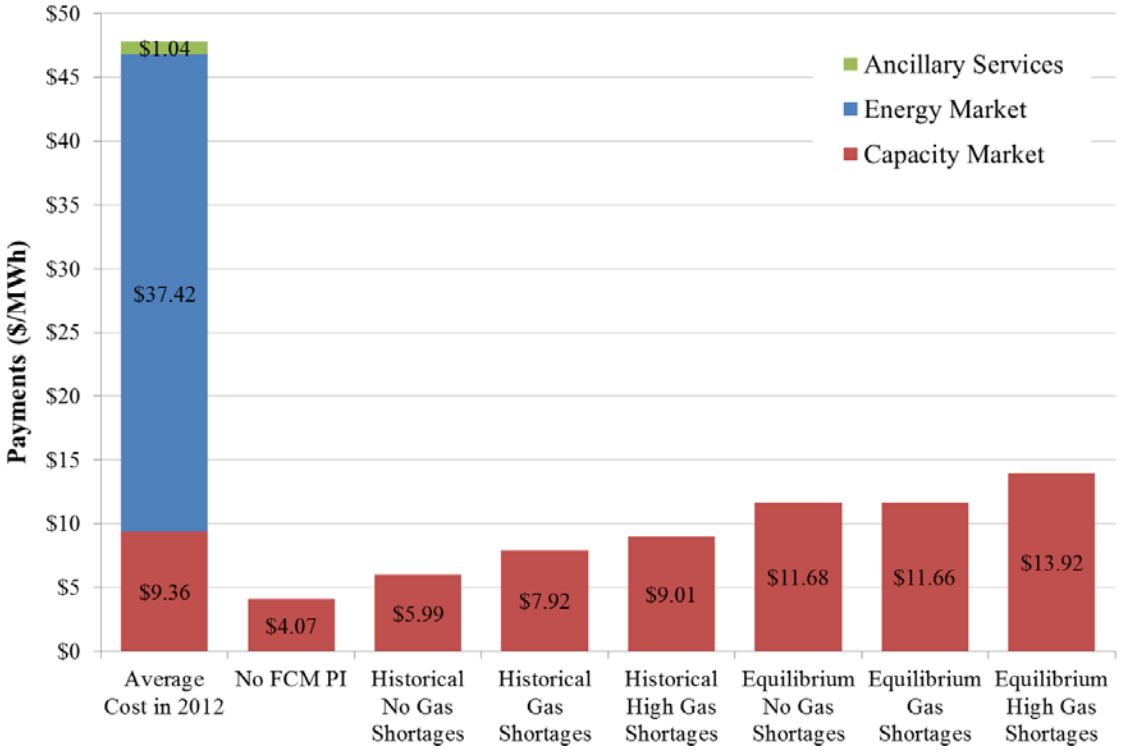
As shown by the scenarios with no gas shortages, when future reserve shortages are driven largely by summer peak conditions, the adjustments tend to be relatively small. However, when future reserve shortages are driven by winter gas supply limitations, the adjustments tend to be relatively large, reflecting the fact that performance of these flexible resources tends to be high during tight winter gas periods. For example, for a new combined cycle unit in the near-term equilibrium, these adjustments are $1.37 per kW-month in the Equilibrium: High Gas scenario. Because the level of adjustments in these Equilibrium scenarios reflects a level of reserve shortages with over 1 GW of surplus capacity, downward

[49] This conclusion does not reflect any adjustments due to financial risk.

adjustments in subsequent years (or the long-term equilibrium) could be greater as the quantity of surplus capacity decreases, and the expected level of reserve shortages increases.

Payments by load follow changes in FCM prices. Consequently, the introduction of FCM PI increases aggregate payments and payments per MWh compared to current rules. Figure 13 shows payments per MWh with and without FCM PI, and also compares these to current payment levels (as reflected in average 2012 payments). Compared to 2012 FCM payments, which reflect the administratively set price floors,[50] payments with FCM PI are lower than current levels under the Historical scenarios (by 4% to 36%, as shown in Table 4), but are higher than current levels under the Equilibrium scenarios (by 25% to 49%). When measured relative to all wholesale electricity market payments, these changes represent an even smaller fraction. For example, under the Equilibrium: No Gas Scenario, FCM payments are $11.68 per MWh with FCM PI compared to $9.36 per MWh in 2012. While this reflects a 25% increase in FCM payments, this increase is only 5% of total 2012 wholesale energy payments (of $47.82 per MWh).

Figure 13: Customer Payments Under Various Market Rules and Scenarios



Changes in energy market payments will arise due to changes in the quantity and mix of resources participating in the ISO-NE markets. These impacts are not quantitatively analyzed, although several observations can be made. First, when FCM PI results in surplus capacity above the ICR, this capacity would likely lower energy market prices, all else equal. The magnitude of this effect will depend

[50] This reflects the prorating of capacity supply obligations.

on energy market offers from those resources that remain in ISO-NE markets that would otherwise have exited the market, absent FCM PI. Surplus capacity will also diminish the level of reserve shortages, which in turn reduces RCPF payments. A simplified calculation indicates that the reduction in RCPF payments could range from $63 to $265 million.[51]

Second, to the extent that FCM PI encourages participation of higher performing units, including units with more competitive heat rates, then this greater performance would flow through to customers in lower energy market prices.

The results indicate that FCM PI would likely raise FCA prices under most circumstances when prices clear below the cost of new entry. However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Increases in FCM payments under the equilibrium scenarios (relative to 2012 levels) would reflect a 5% to 10% increase in 2012 wholesale energy payments.[52]

D. Sensitivity to Model Assumptions

The analysis of FCM PI relies on many modeling assumptions. To test the robustness of model results, in this section, we consider the sensitivity of results to three modeling assumptions:

1. Risk factors
2. Environmental costs
3. Restrictions on incremental dual fuel capability for new resources

Tables 8 to 10 report the results of these sensitivities. Each scenario is evaluated under near-term Equilibrium conditions. In general, conclusions about the impact of FCM PI do not change materially as a consequence of changes to the assumptions tested.

[51] This calculation assumes: reserve shortages levels reported in Table 4; load of 20,000 MW during winter gas reserve shortages and 26,000 MW during summer peak reserve shortages; and RCPF values of either $250 per MWh (for 30-minute local reserves) or $850 per MWh (for 10-minute system reserves). The reduction in payments ranges from $62.6 to $78.0 million at the $250 per MWh RCPF, and $212.9 to $265.2 million at the $850 MWh RCPF across the range of reserve shortage hours used in the Equilibrium scenarios.

[52] This reflects an increase in FCM payments of $2.30 per MWh (Equilibrium: Gas) and $4.56 per MWh (Equilibrium: High Gas) relative to a total payment of $47.82 per MWh.

Table 8: Market Outcomes for Risk Factor Sensitivity Analysis

	With Risk Factors		Without Risk Factors
	Current Rules (No FCM PI)	FCM PI	FCM PI
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$3.76
Total FCM Payments ($bil)	$0.54	$1.56	$1.56
Avg Payments FCM ($/MWh)	$4.07	$11.68	$11.68
% Change Relative to 2012 Level	-57%	25%	25%

As seen in Table 8, elimination of the risk factor results in no change in outcomes for the Equilibrium: No Gas Scenario. This result arises because eliminating the risk factor does not change either the marginal unit that clears the FCM (which could occur if the risk factors affected the order of resource offers in the offer curve), or the offer of the marginal unit offer. Thus, although many resources incorporate a risk factor into their offers (as shown in Figure 6), risk factors do not affect the clearing price. .

Table 9: Market Outcomes for Environmental Cost Sensitivity Analysis

	Without Environmental Costs		With Environmental Costs	
	Current Rules (No FCM PI)	FCM PI	Current Rules (No FCM PI)	FCM PI
FCA Clearing Price ($/kW-month)	$1.31	$3.76	$2.00	$4.17
Total FCM Payments ($bil)	$0.54	$1.56	$0.83	$1.73
Avg Payments FCM ($/MWh)	$4.07	$11.68	$6.20	$12.95
% Change Relative to 2012 Level	-57%	25%	-34%	38%

The introduction of costs to comply with environmental regulations (Section §316(b) regulation of cooling water intake structures) increases the FCA clearing prices with and without PI. As shown in Table 9, under current market rules, FCA prices increase from by $0.69 per kW-month (from $1.31 per kW-month to $2.00 per kW-month) due to the higher FCA offers submitted by resources that need to comply with these regulations. Under FCM PI, FCA prices increase by $0.41 per kW-month (from $3.76 per kW-month to $4.17 per kW-month). Thus, FCM PI has a relatively similar impact on FCA clearing prices with and without the additional environmental costs.

Table 10: Market Outcomes for Dual Fuel Restrictions Sensitivity Analysis

	Equilibrium, High Gas		
	Current Rules (No FCM PI)	FCM PI	FCM PI Restricted DF
FCA Clearing Price ($/kW-month)	$1.31	$4.49	$4.49
Total FCM Payments ($bil)	$0.54	$1.86	$1.86
Avg Payments FCM ($/MWh)	$4.07	$13.92	$13.92
% Change Relative to 2012 Level	-57%	49%	49%

The last sensitivity evaluates how limits on the ability of gas-dependent resources to develop dual fuel capability affect market outcomes. Such limits could occur due to a variety of factors, such as restrictions on environmental permits needed to burn alternative (non-gas) fuels. To evaluate these impacts, dual fuel adoption is limited to those facilities with dual fuel capability that is currently decommissioned. Table 10 shows that, under Equilibrium: High Gas conditions, FCA prices with PI remain unchanged at $4.49 per kW-month with the dual fuel restrictions. Thus, the restrictions do not affect FCA prices. However, with these restrictions, the quantity of dual fuel resources falls from 13,595 MW to 8,906 MW, a reduction of 4,689 MW. Thus, while restrictions on dual fuel capability may not affect the FCA price, they could affect the reliability benefits achieved by FCM PI.

VII. EVALUATION OF OTHER OPTIONS

Our analysis considers an alternative proposal, offered by NRG, to ISO-NE's proposed FCM PI.[53] ISO-NE identified this alternative for evaluation, in part, because it was developed in sufficient detail early enough in the stakeholder process that it could be analyzed in the context of the initiative proposed by ISO-NE. This proposal includes multiple elements, which we describe below.[54] Following these descriptions, we provide quantitative and qualitative assessment of this alternative in comparison to FCM PI.

A. NRG Alternative

NRG has proposed an alternative to FCM PI that includes several elements.[55]

[53] Although other stakeholders offered alternative proposals, ISO-NE viewed these proposals as insufficiently developed to warrant detailed quantitative analysis.

[54] NRG, "FCM Performance Incentives – An Alternative Proposal," November 16, 2012; Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013. Available at http://www.iso-ne.com /committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_nrg_alternative_proposal_11_16_12_ .pdf and http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013 /a10d_nrg_presentation_08_07_13.ppt.

[55] NRG also proposed certain changes to market rules regarding the type of costs that can be included in FCA offers for existing resources. We did not evaluate these changes because they were considered outside the scope of analysis appropriate for the Impact Assessment.

First, current RCPF's would be increased by $5,455 per MWh above current levels. Thus, energy market prices could rise as high as $6,305 per MWh during reserve shortages.[56]

Second, the Peak Energy Rent (PER) Adjustment would be eliminated. Current FCM rules include a PER Adjustment that reduces FCM payments whenever prices exceed a predetermined price threshold. By eliminating the PER Adjustment, the change in RCPFs results in changes in energy market revenues that are not also offset by subsequent PER Adjustments (which are fixed for each MW of capacity). However, these additional energy revenues streams would affect each unit's going forward cost, which in turn would result in reductions in FCM offers. Consequently, under the NRG Alternative, these PER Adjustments would be eliminated.[57]

Third, an "EFOR-based" mechanism would be implemented as part of the FCM. This new mechanism would adjust actual FCM payments received by individual resources such that (1) aggregate FCM revenues would remain unchanged (i.e., revenue-neutral once the FCA has cleared), and (2) each unit's payments would adjust upward or downward depending on its how its *availability* compares to a resource- or unit-specific benchmark.

The "EFOR-based" mechanism includes several components.[58] First, performance would be based on availability metrics reflecting performance during high demand periods, which could reflect a predetermined number of peak load hours (e.g., the top 100 highest load hours) or reserve shortages. These alternatives would have different implications for when performance is measured. Reserve shortages can occur during periods of peak load, but they can also occur during other periods, including winter periods or even shoulder seasons (when maintenance may reduce the supply of available resources). Consequently, reserve shortage hours are typically less predictable than peak load hours, which are typically concentrated during summer periods. An EFOR-based mechanism can also differentially weight hourly availability based on each hour's "importance" for reliability.[59] In other respects, the availability measurement would follow the same type of procedures used in calculating the Effective Forced Outage Rate (EFOR).[60] Second, the FCA (and subsequent reconfiguration auctions) would establish the aggregate payments from load to resources.

Third, FCM payments to each unit would be adjusted based on each unit's availability relative to a pre-determined benchmark. In principle, the benchmark could be based on unit-specific or class-

[56] Note that the NRG Alternative did not specify the value of RCPF assumed, but rather tied the value to the proposed PPR under FCM PI. The current RCPF for ten minute non-spinning reserve (TMNSR) is $850 per MWh, which would rise to $6,305 per MWh with the proposed increase. Other RCPFs would also rise: the system thirty minute operating reserve (TMOR) RCPF would rise to $5,955 per MWh and the local TMOR would be $5,655 per MWh.

[57] If PER Adjustments remain in place with the proposed increase in RCPF values, the financial outcome would be similar to FCM PI. Both the PER Adjustments and PI balancing ratio adjustments operate similar to a financial option, in which resources must pay load whenever certain conditions occur. While the specifics of these options differ somewhat, they are similar enough that an NRG Alternative with PER Adjustments would have many similarities to FCM PI.

[58] *See* Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013, slides 5-10.

[59] For example, "UCAP" rules used in ISO-NE's earlier capacity markets adjusted capacity based on an EFOR-based mechanism that weighted availability differentially across hours of the year.

[60] North American Electric Reliability Corporation (NERC), "GADS Data Reporting Instructions," Appendix F – Performance Indexes and Equations, January 2012.

specific historical availability. The assessment presented below assumes a unit-specific benchmark. The change in FCM payment to each resource would be based on the following formula:

$$\Delta FCM\ Payment = MW\ Deviation * FCM\ Price * Marginal\ Multiplier$$

The *FCM Price* would equal the clearing price from the appropriate auction, and the *Marginal Multiplier* is a fixed multiplier that shifts revenue adjustments upwards or downwards. Each unit's *MW Deviation* would reflect differences between its actual and baseline share of available system capacity, which would reflect its availability (relative to its unit-specific benchmark) as well as the availability of all other units in the system (relative to their respective benchmark availability). NRG materials provide further details.[61]

This analysis considers two aspects of the NRG Alternative:

1. $5,455 RCPF Increase + Elimination of PER
2. EFOR-based mechanism

These two elements of the NRG Alternative are evaluated separately to simplify the assessment. The analysis of the NRG Alternative is performed within the same model used to evaluate FCM PI. First, net energy market revenues are adjusted for the elevated prices during reserve shortages and the level of reserve shortages. When comparing the NRG Alternative to FCM PI, we assume the same level of reserve shortage hours; this assumption arises from the conclusion (discussed further below) that the two models provide comparable levels of reliability (assuming that the PPR and RCPF increases are set at the same level). Thus, we assume that there are no resources with energy market offers above the current RCPF values that could mitigate the reserve shortage. Next, FCM revenues are adjusted downward to reflect reduced FCA offers given the reduction in GFC from the additional energy market revenues.

B. Analysis of the NRG Alternative: $5,455 RCPF Increase + Elimination of PER Adjustment

Under both FCM PI and the NRG Alternative, actions to improve resource performance are induced through incremental revenues to resources that supply during reserve shortages. Thus, because both FCM PI and a $5,455 increase in the RCPF will have similar market outcomes and marginal incentives, the anticipated reliability benefits between these proposals should be quite similar. Thus, for the most part, the reliability impacts identified in Section VI.A would be expected under the NRG Alternative, as well as FCM PI.

Table 11 and Figure 14 provide a comparison of FCM clearing prices, energy market payments and total payments by load between FCM PI and the NRG Alternative for the Equilibrium: No Gas scenario. Under the NRG Alternative, FCA offers are reduced to reflect the increase in energy market revenues, which reduces each unit's going forward cost. As a result of these lower offers, the FCM clearing price will be lower than clearing prices under current rules or FCM PI. In fact, in the Equilibrium: No Gas scenario, under the NRG Alternative, the FCA clears at a price of zero. This means that there are sufficient economic resources that do not need FCM revenues to maintain profitable

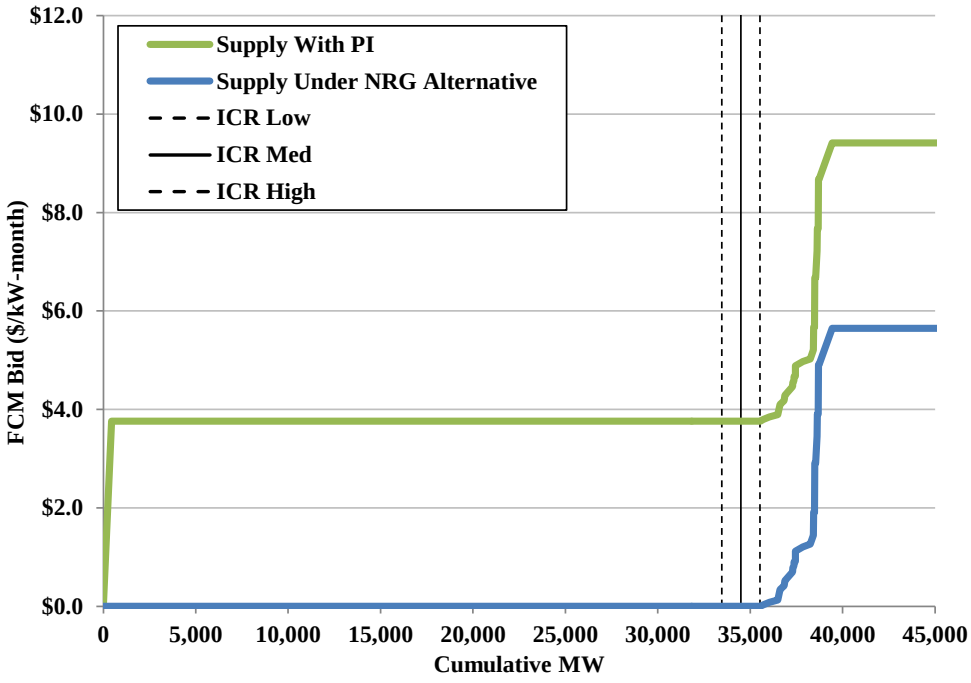
[61] *See* Fuller, Pete, NRG, "Market Reform Proposal," NEPOOL Markets Committee, August 7, 2013, slides 7-8.

operation (i.e., resources with negative going forward costs) to meet the ICR. In practice, if this occurs, market outcomes could reflect bidding behavior in which market participants submit FCA offers that exceed the resource GFC, resulting in a clearing price that is greater than zero.[62] We do not model bidder behavior under these circumstances. To the extent that the FCA cleared with positive prices under this scenario, payments under the NRG Alternative would exceed those under FCM PI by the FCM payments corresponding to this positive FCA price.

Table 11: Market Outcomes with FCM PI and NRG Alternative, Equilibrium: No Gas Scenario

	With FCM PI	With NRG Alternative	Difference
FCA Clearing Price	$3.76	$0.00	($3.76)
FCM Payments ($ billion)	$1.56	$0.00	($1.56)
Additional RCPF Payments ($ billion)	$0.00	$1.56	$1.56
Total Payments to Suppliers ($ billion)	**$1.56**	**$1.56**	**$0.00**

Figure 14: FCM Offer Curve, FCM PI versus NRG Alternative

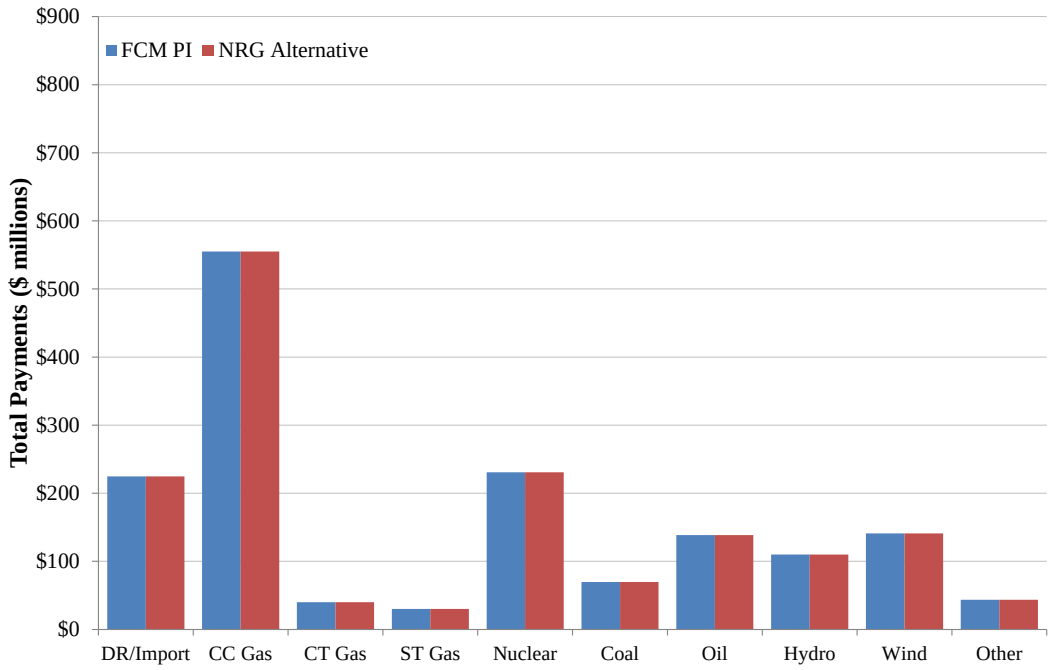


[62] Offers could reflect strategic bidding behavior in an effort to achieve a positive FCA price, or opportunity costs of taking on a CSO (e.g., administrative costs or compliance risk).

Table 11 shows the total FCM payments and the changes in energy market payments, as reflected in increased RCPF values, under FCM PI and NRG Alternative. Under the Equilibrium: No Gas scenario, expected payments are the same under the two alternatives. The NRG Alternative results in additional energy (RCPF) market payments of $1.56 billion, but FCM payments equal zero. By contrast, FCM PI results in FCM payments of $1.56 billion but no change in energy market payments. Thus, both alternatives have the same impact on payments in the FCM and energy markets.

While expected payments are the same under FCM PI and the NRG Alternative, actual payments can differ depending on the actual level of reserve shortages. Consider the three possible outcomes in Figures 15, 16 and 17, which show the payments made under each approach to different resource types for different levels of actual reserve shortages. Figure 15 shows that payments under the two alternatives are the same when the actual and expected levels of reserve shortages are the same. However, Figures 16 and 17 show that when the actual and expected levels of reserve shortages differ, payments under the two models will diverge.[63] These figures illustrate two important differences between the programs.

Figure 15: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Equals Expected Reserve Shortages



First, there is less variation in payments under FCM PI than the NRG Alternative. For each resource category, the change in payments when actual reserves shortage levels differ from expectations is greater under the NRG Alternative than FCM PI. Thus, in aggregate, the NRG Alternative results in greater volatility in payments by load and to suppliers. This greater volatility translates into a higher level of aggregate financial risk for both customers (load) and resources, although, as discussed below, the implications for individual resources vary depending on resource-specific characteristics.

[63] These scenarios assume 9, 5, and 15 reserve shortage hours for Figures 15, 16 and 17, respectively.

Figure 16: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Less Than Expected Reserve Shortages

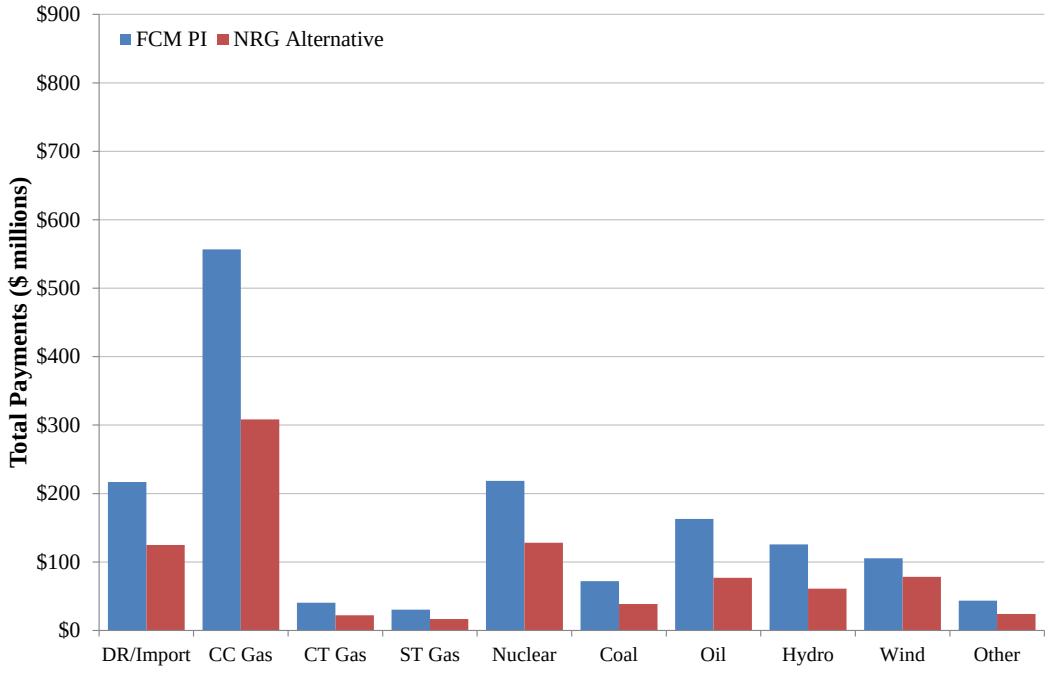
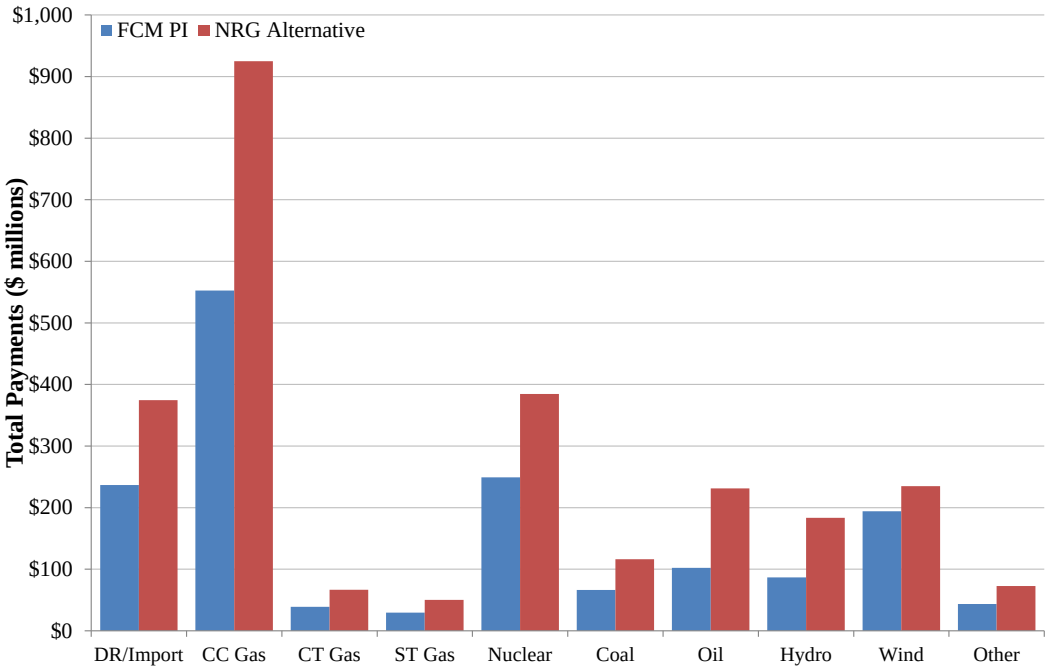


Figure 17: Total Payments Under FCM PI and NRG Alternative by Fuel Type, Actual Reserve Shortages Greater Than Expected Reserve Shortages



Second, under the NRG Alternative, all resources receive higher payments as the level of reserve shortages increases. By contrast, payments under FCM PI can increase or decrease with a higher level of reserve shortages depending on whether the resource is a high or low performer. For example, payments to nuclear resources, with performance levels typically above the balancing ratio, increase from $218 million to $249 million as reserve shortage levels increase (from Low to High). By contrast payments to oil resources decline from $163 to $102 as reserve shortage levels increase (from Low to High).

Figures 15 to 17 unmask some important differences in payment volatility between the two alternatives that are relevant for individual resources. Figure 18 shows the payments made under FCM PI and the NRG Alternative to illustrative units under varying levels of reserve shortages. The figures (calculated for Historical conditions) show that for individual resources, the implications of uncertainty in reserve shortages vary significantly depending on the resource's performance. For high performing units (90-100%), payments vary little under FCM PI, whereas they vary by nearly a factor of three under the NRG Alternative. For average performing units (60-70% performance), variation is still less under FCM PI than the NRG Alternative, although the degree of variation is of the same order of magnitude. However, for low performing resources (10-20%), variation is greater under FCM PI, and the resource faces the risk of negative net FCM payments. Thus, while FCM PI results in less financial risk for high performing resources, financial risk is greater for low performing resources relative to the NRG Alternative.

C. Analysis of the NRG Alternative: EFOR-based mechanism

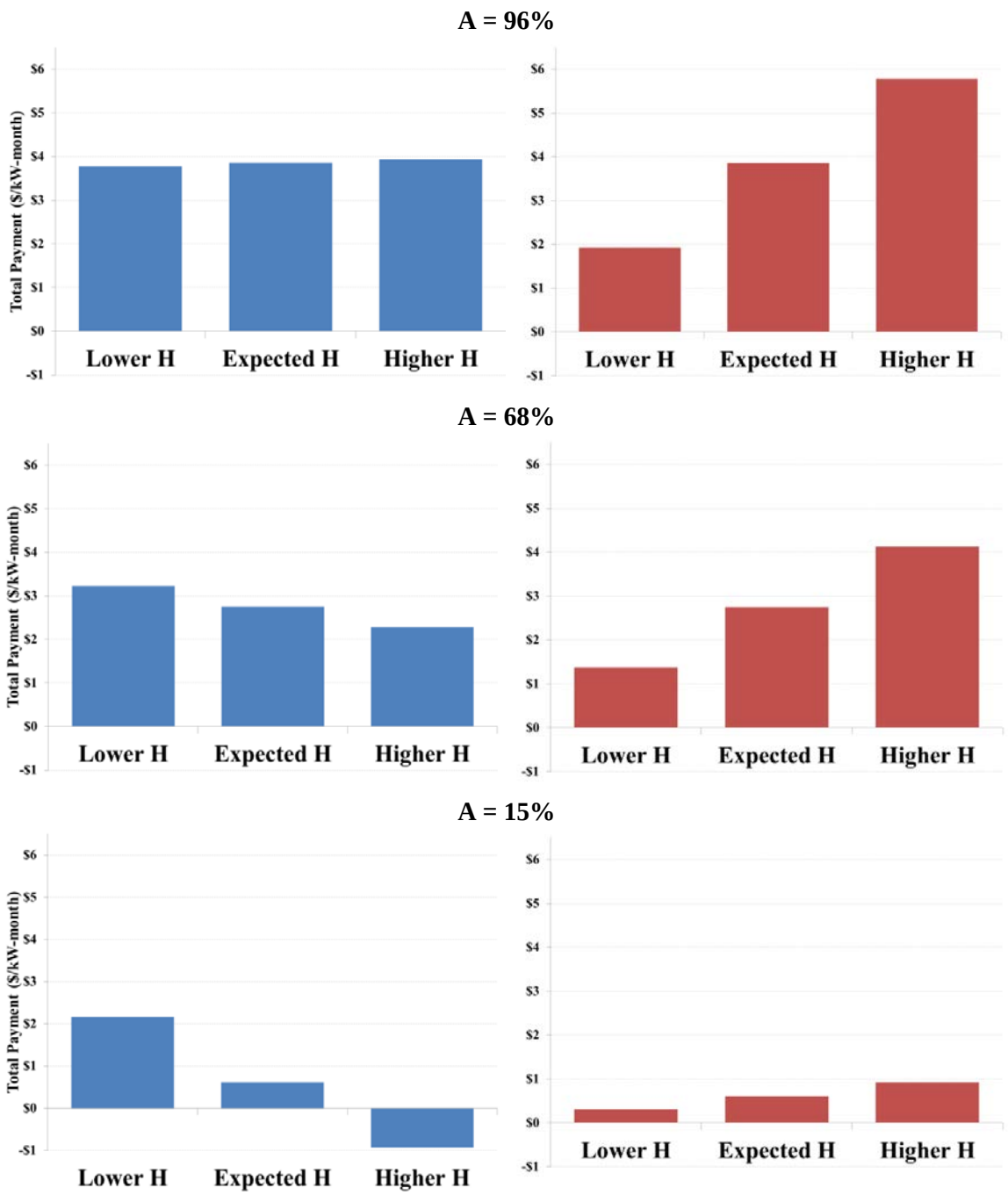
The introduction of the EFOR-based mechanism (in addition to the $5,455 RCPF increase and the elimination of the PER Adjustments) could have implications for both reliability and market outcomes. From a reliability standpoint, the introduction of EFOR-based incentives for availability in addition to the increase in RCPFs of $5,455 per MWh would further enhance the incentives to improve performance. The incremental incentives would be limited to actions that improved *availability*, but would not affect other sorts of operational performance. Our analysis does not consider any quantitative benefits that would arise from these additional incentives.

In terms of potential market outcomes, impacts would depend strongly on assumptions about expected future performance. The EFOR-based mechanism could affect resource offers depending on the expectations of each market participant regarding future resource availability compared to the benchmark against which each resource's availability is measured.

Under the NRG Alternative, benchmarks would be set at the individual resource level based on historical availability. Under this rule, the most reasonable assumption about a market participant's expectation about future availability is that it will reflect past historical availability. However, if resource benchmarks are also based on historical availability, then market participants' expectations about future availability would equal the benchmark availability. Consequently, market participants would not expect to win or lose as a consequence of the rule, and would not adjust their FCM offers, leaving FCA prices unchanged.

If benchmarks were set based on broader resource categories, then resources would find it optimal to adjust their offers upward or downward depending on whether their past availability was higher or lower than their category average. We have not quantitatively evaluated such a proposal.

Figure 18: Payments to Illustrative Individual Units Under FCM PI and the NRG Alternative



VIII. CONCLUSIONS

The assessment of ISO-NE's FCM PI proposal has identified a range of changes to reliability, costs and payments by load. The assessment identifies many types of potential impacts and analyzes these through quantitative estimates and qualitative assessments.

These results indicate that FCM PI would likely result in improvements to reliability through several mechanisms, including: increases in the quantity of resources participating in the ISO-NE markets; investments to improve resource performance, including investments to develop dual fuel capability at gas-dependent resources; and changes to the mix of resources that remain in the ISO-NE fleet and are used to satisfy the region's Installed Capacity Requirement. Reliability benefits would likely be greatest in summer peak load periods (from surplus capacity) and in winter months, particularly during periods of high gas demand (from surplus capacity and dual fuel investments).

FCM PI would result in a variety of cost impacts, including changes to production costs, new investments to improve performance, and potential delays in the timing of when new generation resources are required to meet the ICR. Our analysis does not quantitatively estimate the net impact of these various effects.

The results indicate that FCM PI would likely raise FCA prices under most circumstances when prices clear below the cost of new entry (under current market rules). However, FCM PI would likely lower offers from new entry due to the incremental revenues provided under FCM PI, particularly as these resources are likely to (and under FCM PI have incentives to) be high performing resources. Consequently, in the long-run, FCM PI could lower FCA prices as the market nears an equilibrium in which new generation resources are required. Increases in FCM payments under the equilibrium scenarios would reflect a 5% to 10% increase in 2012 wholesale energy payments.

The key element of the NRG Alternative – the $5,455 increase in RCPF values – would provide comparable reliability benefits and expected costs, but have different implications for the financial risk born by suppliers and load given the variation in aggregate payments under the NRG Alternative compared to FCM PI. FCM PI would reduce variation in total FCM payments, which would be not exceed the prices established in the FCA. Under the NRG Alternative, FCM payments would vary depending on system conditions (the level of reserve shortages, and loads during these shortages) during the commitment period.

APPENDIX A: METHODOLOGICAL APPROACH AND DATA ASSUMPTIONS

A. Going-Forward Costs

Going-forward costs are calculated using the following formula:

$$Offer(FCM) = \frac{GFC + RF}{Capacity * 12} = \frac{FC + I - Q*\left(P - VC - HR*P_{Fuel}\right) + RF}{Capacity * 12}$$

Fixed costs (*FC*) and investments (*I*) are offset by the remainder of the equation, reflecting net energy and ancillary services market revenues, where *Q* is the quantity of output sold, *P* is the average energy market price, *VC* is the non-fuel variable costs, *HR* is the unit's heat rate, and P_{Fuel} is the fuel price. *RF* is the risk factor. *Capacity* reflects the resources Summer Qualified Capacity, the quantity (in MW) of each resource's nameplate capacity that is eligible to bid into the FCA (for the summer months). The individual elements of the above formula are calculated using the following data and assumptions.

Fixed Costs

Fixed O&M costs for each unit are reported in SNL Financial for 2011. These values are adjusted to reflect a $/kW-year cost and applied to each unit's Summer Qualified Capacity as reported in FCA 7. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type. For imputed fixed costs, an additional random noise factor of 0-1% is added, to avoid a situation where multiple units have the same GFC. Costs for certain resources were adjusted in light of resource- or region-specific information about costs from a variety of sources.

Investment Costs

Investment costs are broken into two components: costs to install and operate dual-fuel fired capability and costs to install and operate equipment for environmental compliance. Other investments needed for resources to continue operations are not considered. Appendix C provides detail on the methodology, data, and assumptions used for dual-fuel investment decisions.

The need for environmental compliance equipment installation is based on Analysis Group's review of prior ISO-NE analyses of which generators may face CWA Section §316(b) regulations. The analysis assumes that 50% of the overall capacity potentially at risk actually faces additional Section §316(b) requirements, including all coal units, the two oldest nuclear plants, and the oldest oil units. In total, 19 generators are assumed to face additional environmental investments to continue operation.

Fossil fuel units facing compliance costs are assessed a 1.3% penalty to heat rate and a 3.4% penalty to MW capacity. For nuclear generators, there is a 1.5% penalty to heat rate and 1.0% penalty to MW capacity. Depreciation of investment costs is based on the useful life remaining of the asset, using

ISO-NE Market Rule guidance and the Offer Review Trigger Price (ORTP) study performed by Shaw Consultants International, Inc.[64] In addition, a depreciation tax shield is assumed on investment costs, of:

$$Corporate\ Tax\ Rate * \left(\frac{Upfront\ Costs}{5\ years}\right).$$

A discount rate of 5.67% is used for calculating investment costs, representing the Weighted Average Cost of Capital (WACC) methodology provided in Shaw Consultants' ORTP study, updated to reflect current market rates.

Variable Costs

Variable O&M costs for each unit are reported in SNL Financial for 2011. These values are adjusted to reflect a $/MWh cost and applied to each unit's average of 2010-2012 actual net generation as reported by ISO-NE. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type.

Fuel expenditures are calculated using unit heat rates and fuel costs. Unit heat rates are based on SNL Financial data for 2011. Values for units that do not have reported data in SNL are imputed based on category averages for similar units based on unit size, vintage, and fuel type.

Natural gas prices are based on NYMEX Henry Hub natural gas futures for 2018-2019, and are then adjusted to account for a basis differential reflecting the difference in prices between Henry Hub and New England hub prices over the last three years. Oil and coal price forecasts are delivered fuel prices to electricity generators in the New England region from EIA's 2013 Annual Energy Outlook. Nuclear fuel prices reflect the reported unit prices from SNL for 2011, with no anticipated change.

Revenues

LMPs are estimated based on a regression of unit-level average annual LMPs on year-end natural gas prices. This specification is consistent with the assumption that gas-fired resources are the marginal units during most hours in recent years. A separate regression is run for each technology/fuel type, with unit-level fixed effects. The results of these regressions are used to forecast expected average prices for each unit for the 2018/2019 commitment year. Average LMP estimates are calculated using the technology/fuel-specific parameters for gas prices, forecast gas prices, and each unit's individual fixed effect. Through this approach, both fuel-level and unit-level heterogeneity are captured in the LMP model. ISO-NE LMP data from 2007-2012 are used in the regression model.

Ancillary service payments are collected from ISO-NE data for NCPC payments, regulation payments, and real-time reserve payments. The 2018-2019 ancillary payments per MWh for each unit are assumed to be the average of actual payments per MWh over 2010-2012.

[64] While new ORTP values developed by Brattle Group and Sargent & Lundy are used, the financial assumptions used in assessing capital investments based on the prior Shaw ORTP study.

Non-Reported Revenues

All cogeneration plants, and plants running on biomass, hydro, solar, fuel cells, or wind are assumed to have a GFC equal to zero. This is based on the expectation that these plants will have significant non-energy-market revenues or credits that are not captured in the data sources used.

Other Inputs

The inflation index used was the Federal Reserve Board's prediction of long-run PCE inflation, 2.0%.[65] Details on the risk factor methodology and calculation can be found in the main text of the report in Section V.F.

Going-Forward Costs for New Entry

New unit going-forward cost estimates are taken from the study of Offer Review Trigger Prices (ORTP) performed by the Brattle Group and Sargent & Lundy.[66] The model only considers new entry for combined cycle and combustion turbine resources, although the study evaluates other resource types.

B. Operational Performance

Data used to estimate operational performance *A* and balancing ratio *BR* is as follows:

1. Average Historical Conditions: Estimates reflect performance during all system reserve shortages that occurred during the period 2010 to 2012.[67]
2. Peak (Summer) Conditions: Estimates reflect performance during all system reserve shortages that occurred during the months of June, July and August during the period 2010 to 2012.
3. Winter Peak Conditions: Estimates reflect performance during all hours when the balancing ratio exceeded 0.6 during winter months in the years 2010 to 2012.[68]

[65] Federal Reserve Board, "Economic Projections of Federal Reserve Board Members and Federal Reserve Board Presidents, March 2013," March 20, 2013. Available at: http://www.federalreserve.gov/monetarypolicy/files /fomcprojtabl20130320.pdf.
[66] Brattle Group, "ISO-NE Offer Review Trigger Prices 2013 Study, Final Results," presented to the NEPOOL Markets Committee, September 10, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps /mrkts_comm/mrkts/mtrls/2013/sep10112013/a02_the_brattle_group_presentation_09_10_13.ppt.
[67] System reserve shortages considered include shortages under the current RCPFs of $500 per MWh for TMOR. These include actual reserve shortages from June to December 2012, when $500 TMR RCPFs were in effect, and reserve shortages identified in simulations performed by ISO-NE for the period January 2010 through May 2012. These data are reported in ISO-NE, "Reserve Constraint Penalty Factor Activation Data, October 2006 - December 2012," March 5, 2013. Available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls /2013/mar11122013/a14_iso_rcpf_activation_data_03_05_13.xlsx.
[68] Across units, performance during system reserve shortages in winter months was highly variable. Consequently, performance during high load periods, as reflected by the balancing ratio, was used in lieu of performance during reserve shortages.

Performance is measured as the ratio of total output and operating reserves (*MW*) supplied over all of the reserve shortages (*RS*) (during the relevant time period) divided by the product of the total qualified capacity (*SCC*) and the duration of the reserve shortages (*H*) – that is:

$$A = \frac{\sum_{RS} MW}{SCC * H}$$

Performance is measured over the resource's entire eligible capacity.

The balancing ratio equals load plus reserves divided by ICR. The average balancing ratio equals the sum of the loads during all reserve shortages divided by the product of the ICR times the number of reserve shortages hours – that is:

$$BR = \frac{\sum_{RS} L}{ICR * H}$$

C. Demand Response, Imports, and Renewables

Demand response (DR) is assumed to bid into the FCM PI model in the same amounts as FCA 7. Two categories of DR exist in the model:

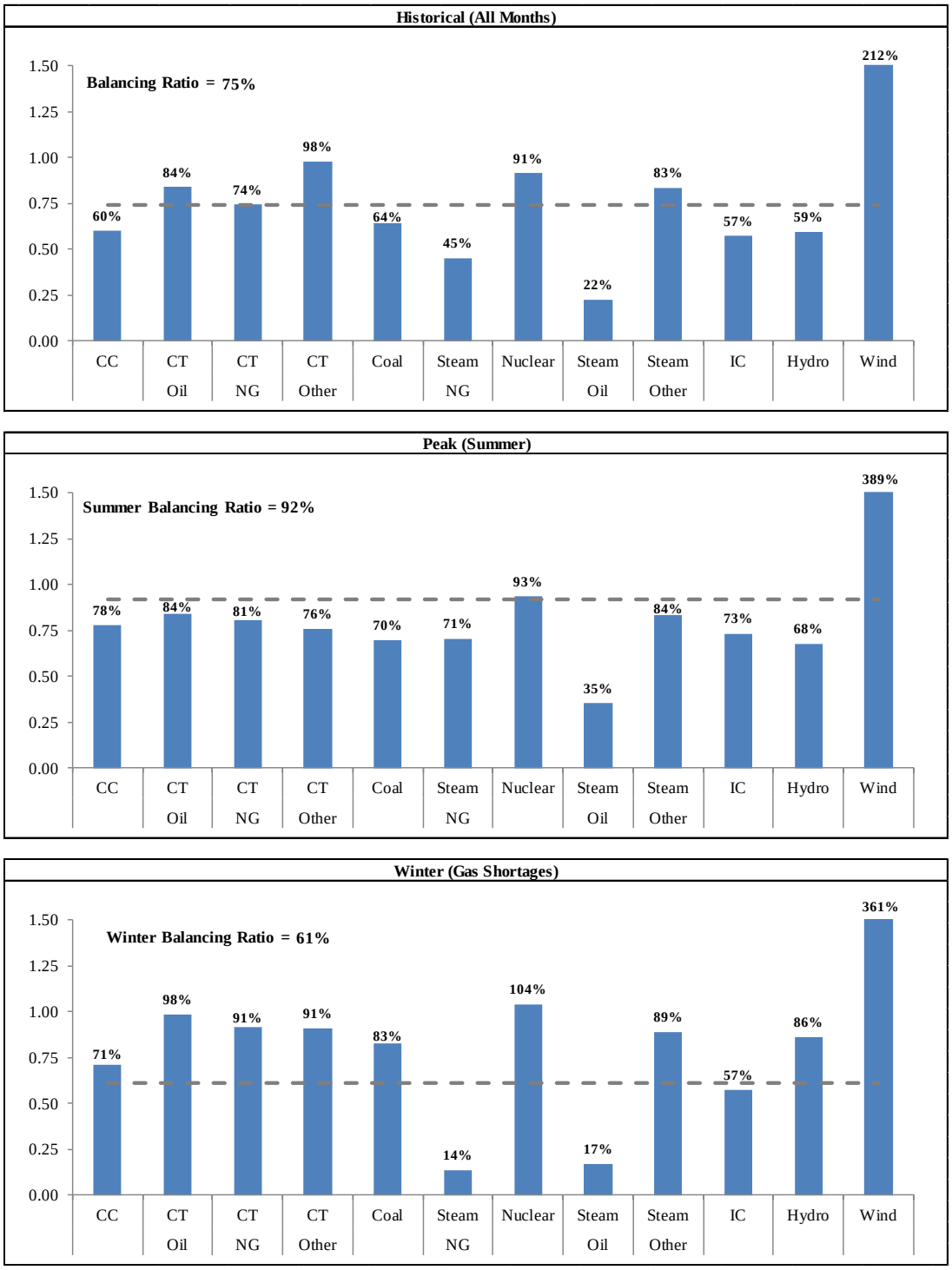
1. Passive DR: 1,850 MW of supply is assumed to be fixed given existing utility-operated energy efficiency programs. These resources are "price takers" in the model – that is, they will accept any price.
2. Active DR: Lacking detailed information on the supply of DR at various prices, the aggregate supply of DR is assumed to grow linearly between several known price/quantity pairs from FCA 7 (i.e., the quantity supplied at each price in the descending clock auction). Starting at bids of $14.00, 856 MW of DR delists linearly in 50 cent increments down to $0.50. The remaining 917 MW of DR is assumed fixed (i.e., resources are price takers down to a very low price).

Imports are treated similarly to active DR in the FCM PI model. The 1,830 MW of imports with capacity supply obligations in FCA 7 are assumed to linearly delist in 450 MW and $1.00 increments starting at $4.00, with the last 30 MW bidding in at $0.10.

Sufficient renewables are added to the fleet to meet state RPS standards in 2018-2019. Based on the most recent ISO New England Regional System Plan[69], 1,142 MW of onshore wind is added beyond what has already cleared in FCA 7 to achieve these requirements. This capacity total reflects the quantity of renewables eligible for the FCM, using a 31% capacity factor.

[69] ISO New England, "Regional System Plan", November 2, 2012.

Figure A1: Average Unit Performance by Resource Category



[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] Summer SCC, generation type, and primary fuel type from CELT Reports. Operating data from ISO-NE.

Table A1
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
All Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	Mean	Standard Deviation	Minimum	Maximum	Aggregate Class Performance
Combined Cycle	0.60	1.20	0.00	12.40	0.67
Gas Turbine/Oil	0.84	0.46	0.00	1.92	0.93
Gas Turbine/Natural Gas	0.74	0.45	0.00	1.30	0.84
Gas Turbine/Other	0.98	0.37	0.00	1.55	0.94
Steam/Coal	0.64	0.43	0.00	1.07	0.89
Steam/Natural Gas	0.45	0.37	0.00	1.06	0.60
Steam/Nuclear	0.91	0.26	0.00	1.18	1.02
Steam/Oil	0.22	0.40	0.00	1.25	0.28
Steam/Other	0.83	0.40	0.00	2.73	0.99
Internal Combustion Engine	0.57	0.52	0.00	2.58	0.64
Hydro	0.59	2.19	0.00	30.65	0.78
Wind Turbine	2.12	2.60	0.00	10.02	3.28

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012.

Table A2
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
Summer Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	**Mean**	**Standard Deviation**	**Minimum**	**Maximum**	**Aggregate Class Performance**
Combined Cycle	0.78	1.05	0.00	10.61	0.86
Gas Turbine/Oil	0.84	0.38	0.00	1.92	0.93
Gas Turbine/Natural Gas	0.81	0.34	0.00	1.16	0.92
Gas Turbine/Other	0.76	0.33	0.00	1.22	0.72
Steam/Coal	0.70	0.35	0.00	1.07	0.99
Steam/Natural Gas	0.71	0.25	0.00	1.06	0.91
Steam/Nuclear	0.93	0.14	0.66	1.18	1.04
Steam/Oil	0.35	0.44	0.00	1.25	0.43
Steam/Other	0.84	0.36	0.00	2.36	1.03
Internal Combustion Engine	0.73	0.42	0.00	1.65	0.77
Hydro	0.68	1.48	0.00	16.77	0.90
Wind Turbine	3.89	2.30	0.00	10.02	4.60

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012. Data are limited to reserve events during June, July, and August.

Table A3
Unit and Class Performance During System Reserve Shortage Events
Summary Statistics by Generation/Primary Fuel Type
Winter Months January 2010 - December 2012

	Unit Performance				
Generation/Primary Fuel Type	Mean	Standard Deviation	Minimum	Maximum	Aggregate Class Performance
Combined Cycle	0.71	1.51	0.00	11.90	0.72
Gas Turbine/Oil	0.98	0.45	0.00	1.71	1.00
Gas Turbine/Natural Gas	0.91	0.51	0.00	1.37	0.89
Gas Turbine/Other	0.91	0.51	0.00	1.45	0.90
Steam/Coal	0.83	0.29	0.00	1.07	0.97
Steam/Natural Gas	0.14	0.37	0.00	1.08	0.16
Steam/Nuclear	1.04	0.10	0.45	1.18	1.04
Steam/Oil	0.17	0.37	0.00	1.11	0.20
Steam/Other	0.89	0.41	0.00	2.50	0.98
Internal Combustion Engine	0.57	0.51	-0.14	2.19	0.57
Hydro	0.86	1.96	0.00	14.45	0.88
Wind Turbine	3.42	3.32	0.00	10.83	3.73

Notes:
[1] "Unit Performance" is calculated for each unit and event as a unit's average output during the event divided by its summer seasonal claimed capability (summer SCC). The summer SCC used is from the most recent year with available data. Mean unit performance is weighted by summer SCC.
[2] "Aggregate Class Performance" is calculated as total class output divided by total class summer SCC.
[3] Summer SCC, generation type, and primary fuel type from CELT Reports. For each unit, data comes from the most recent year with available data.
[4] The system RCPF value equaled $100 until June 1, 2012, at which point it was increased to $500. ISO-NE used a simulation to determine when reserve events would have occurred with a system RCPF value of $500 for the period from January 2010 - May 2012. The data from this simulation was used together with data on actual reserve events for the period from June 2012 - December 2012 to calculate unit performance and aggregate class performance for the period from January 2010 - December 2012. Data are limited to periods events during December, January, and February when the balancing ratio exceeded 0.6.

APPENDIX B: DETAILED SCENARIO RESULTS

Table B1: Resource Mix and Average Performance With and Without FCM PI, Historical: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,769	100%	1,739	100%
Renewables	4,705	83%	0	NA
Nuclear	4,628	102%	0	NA
CC Gas	12,470	72%	315	48%
Coal	1,591	73%	543	85%
CT or ST Gas	1,520	72%	122	65%
Oil	4,862	44%	1,786	11%
Other	1,071	87%	0	NA
Total	34,615		4,506	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	83%	0	NA
Nuclear	4,628	102%	0	NA
CC Gas	12,470	72%	315	48%
Coal	1,591	73%	543	85%
CT or ST Gas	1,520	72%	122	65%
Oil	5,601	39%	1,047	27%
Other	1,071	87%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	459	0.0%	-459	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	0	0.0%	0	0.0%
Coal	0	0.0%	0	0.0%
CT or ST Gas	0	0.0%	0	0.0%
Oil	-739	5%	739	-16%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B2: Resource Mix and Average Performance With and Without FCM PI, Historical: Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,258	100%	1,250	100%
Renewables	4,705	91%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	72%	315	47%
Coal	1,703	75%	431	86%
CT or ST Gas	1,499	61%	143	48%
Oil	4,171	40%	2,478	13%
Other	1,070	88%	0	15%
Total	34,504		4,617	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	91%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	72%	315	47%
Coal	1,591	74%	543	89%
CT or ST Gas	1,520	60%	122	52%
Oil	5,601	34%	1,047	21%
Other	1,071	88%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	948	0.0%	-948	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	0	0.0%	0	0.0%
Coal	113	2%	-113	-3%
CT or ST Gas	-21	0.5%	21	-4%
Oil	-1,430	6%	1,430	-8%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B3: Resource Mix and Average Performance With and Without FCM PI, Historical: High Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,705	93%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,442	74%	343	50%
Coal	2,039	78%	95	82%
CT or ST Gas	1,499	61%	143	43%
Oil	3,416	41%	3,232	15%
Other	1,070	88%	0	15%
Total	34,516		4,605	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	93%	0	NA
Nuclear	4,628	104%	0	NA
CC Gas	12,470	74%	315	52%
Coal	1,591	74%	543	90%
CT or ST Gas	1,520	61%	122	48%
Oil	5,601	32%	1,047	19%
Other	1,071	88%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	-28	0.1%	28	-3%
Coal	448	4%	-448	-8%
CT or ST Gas	-21	0.6%	21	-5%
Oil	-2,185	9%	2,185	-4%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B4: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: No Gas Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,717	100%	791	100%
Renewables	4,698	112%	7	4%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	91%	74	22%
Coal	1,703	86%	431	90%
CT or ST Gas	1,642	89%	0	NA
Oil	4,366	66%	2,282	14%
Other	1,070	91%	0	15%
Total	35,536		3,585	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	112%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	92%	315	70%
Coal	1,591	85%	543	93%
CT or ST Gas	1,520	89%	122	91%
Oil	5,601	54%	1,047	39%
Other	1,071	91%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,407	0.0%	-1,407	0.0%
Renewables	-7	0.2%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.1%	-241	-48%
Coal	113	1.3%	-113	-3%
CT or ST Gas	122	0.1%	-122	NA
Oil	-1,235	12%	1,235	-25%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B5: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,917	100%	591	100%
Renewables	4,698	108%	7	27%
Nuclear	4,628	105%	0	NA
CC Gas	12,712	85%	74	36%
Coal	2,039	84%	95	87%
CT or ST Gas	1,642	77%	0	NA
Oil	4,185	58%	2,463	13%
Other	1,070	90%	0	15%
Total	35,890		3,231	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	108%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	85%	315	63%
Coal	1,591	81%	543	93%
CT or ST Gas	1,520	77%	122	75%
Oil	5,601	46%	1,047	32%
Other	1,071	90%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,607	0.0%	-1,607	0.0%
Renewables	-7	0.1%	7	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.3%	-241	-27%
Coal	448	3%	-448	-6%
CT or ST Gas	122	-0.1%	-122	NA
Oil	-1,416	12%	1,416	-18%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

Table B6: Resource Mix and Average Performance With and Without FCM PI, Equilibrium: High Gas Shortage Scenario

Results With FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	4,976	100%	532	100%
Renewables	4,705	106%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,712	84%	74	44%
Coal	2,039	83%	95	88%
CT or ST Gas	1,642	73%	0	NA
Oil	4,201	51%	2,447	13%
Other	1,070	90%	0	15%
Total	35,972		3,149	

Results Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	3,310	100%	2,198	100%
Renewables	4,705	106%	0	NA
Nuclear	4,628	105%	0	NA
CC Gas	12,470	84%	315	63%
Coal	1,591	80%	543	93%
CT or ST Gas	1,520	73%	122	66%
Oil	5,601	42%	1,047	27%
Other	1,071	89%	0	NA
Total	34,896		4,226	

Difference Between With and Without FCM PI

	Cleared Units/In Energy Market		Non-Economic Units	
	Total MW	Average Performance	Total MW	Average Performance
DR/Import	1,666	0.0%	-1,666	0.0%
Renewables	0	0.0%	0	NA
Nuclear	0	0.0%	0	NA
CC Gas	241	-0.3%	-241	-18%
Coal	448	3%	-448	-5%
CT or ST Gas	122	-0.5%	-122	NA
Oil	-1,400	9%	1,400	-14%
Other	0	0.0%	0	NA

Notes:
[1] Total MW Cleared Units/In Energy Market includes economic capacity above the ICR.
[2] Non-economic units include units with neither a capacity supply obligation nor negative going forward costs (including performance incentives).
[3] DR: Demand Response, CC: Combined Cycle, CT: Combustion Turbine ST: Steam Turbine.

APPENDIX C: ASSESSMENT OF ALTERNATIVE TECHNICAL OPTIONS FOR SECURING FUEL SUPPLY

This appendix provides qualitative and quantitative background information on categories of potential costs associated with new infrastructure alternatives to address risks of natural gas fuel curtailment, or "gas dependence" risks. This information is used to identify the least-cost approach to addressing gas-dependency risks. This assessment considers the direct cost of these options, but does not consider indirect economic impacts, such as net revenues gained from increased output in the energy market, or changes in fuel costs.

The assessment relies on various studies, reports, and analyses conducted by third parties and available in the public domain, related to natural gas and dual fuel infrastructure options that could emerge from market rule changes, along with estimates developed by Analysis Group based on information and data provided by ISO-NE or contained in these studies and reports. The list of studies reviewed is presented at the end of this memo.

There are a number of potential technical options that resources can take to address gas dependence risks. Our assessment considers the following options:[70]

- Increases in dual-fuel capability or operations
  - From existing units with dual fuel capability that is currently mothballed or underutilized
  - From newly developed dual fuel capability at existing gas plants
- Storage/transportation arrangements tied to existing LNG facilities
- New in-region LNG storage
- New natural gas interstate pipeline capacity

The identification of the least-cost approach to mitigate gas dependence reflects the cost-effectiveness of each option to resource owners. This assessment also considers (1) feasibility and the timeline for development, and (2) operational characteristics to ensure that the resource owners would have sufficient time to implement the technical option for the commitment period, that there are not regulatory, technical or practical barriers to deploying the option, and that the option addresses gas dependence risks with reasonable certainty. In the sections that follow, information and data are presented for each of these factors, and for each of the options identified. Specifically, we review:

1. *Costs* – life-cycle costs, including upfront costs and annual operating costs.[71] Options are compared based on their annualized cost (dollars per kW-month), reflecting assumptions about the discounting of each option's upfront costs. The cost estimates reflect implementation of the option at generic resources based on data provided by ISO-NE and publicly available information

[70] It should be noted that there may be additional or alternative outcomes of market rule changes focused on natural gas dependence that are not identified or evaluated in this memo.

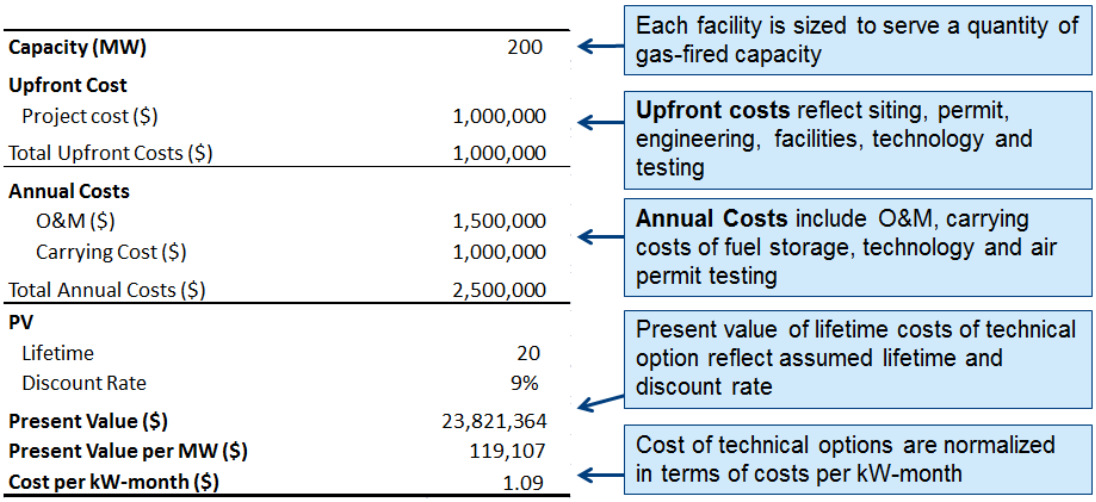
[71] In addition to these infrastructure development and operational costs, the integration of such new infrastructure would likely have an impact (positive or negative) on *system costs* over time. Such impacts could arise, for example, from changes in system unit commitment and dispatch in some or all hours of the year given the integration of new resources, and/or changes in system transmission costs. These system cost impacts are not reviewed in this analysis.

on recent development projects. Unless noted below, the estimates do not reflect resource-specific factors that would lead actual costs to vary from these estimates. Figure C1 describes how categories of costs are identified and normalized to allow for comparison.

2. *Development timeline/feasibility* – the time required between conceptualization and commercialization for the options reviewed varies widely. The analysis presents qualitative assessments of development feasibility and barriers to implementation that would affect when specific alternatives would be available to influence reliability and market outcomes.

3. *Operational characteristics* – not all options reviewed provide equal assurance of fuel delivery or generation availability, and so they present different implications for resource availability that may or may not affect market valuation. For example, options differ in their (1) ability to ensure fuel delivery for prolonged or frequent curtailments, (2) ability to support reserve-quality resources, and (3) ability to withstand interstate natural gas pipeline contingencies. The analysis presents qualitative assessments of operational constraints that would affect how specific alternatives would influence reliability and market outcomes.

Figure C1: Analytic Approach to Estimating Costs of Options to Address Gas Dependence



7In the sections that follow, we summarize results for each of the infrastructure options identified above. Table C1 summarizes the assessment of options to mitigate gas dependency and is equivalent to Table 3.

Table C1: Comparison of Options for Firming Gas-Dependent Resource Fuel Supply

Technology Option		Cost	Other Factors
Dual Fuel	Current Dual Fuel Capable	• $5,700 per MW	• Time to recommission or install is relatively brief • Long refill times may limit effectiveness over long curtailments • Operations limits and risks when switching to alternate fuels • Requires environmental permitting
	Under- or Unutilized Dual Fuel Capability	• $6,500 per MW (annualized, reflecting capital cost and annual expenditures)	
	No Dual Fuel Capability	• $15,000 per MW (annualized, reflecting capital cost and annual expenditures)	
Service from Existing LNG Facilities (Canaport, DOMAC)		• Not estimated – cost would reflect (1) foregone opportunity to sell LNG in higher-value markets; (2) carrying cost; (3) operating cost; and (4) transportation charge. • Rate would be subject to negotiation	• Could be subject to deliverability constraints without firm service (esp. for Canaport, requiring transport over Maritimes pipeline)
New LNG Storage		• $29,700 per MW (annualized, reflecting capital cost and annual expenditures)	• Long refill times may limit effectiveness over long curtailments
New Pipeline Capacity		• $9,700 to $32,700 per MW for upfront costs • Rates for firm service would exceed these annualized costs	• Requires purchase of firm service • Time lag between commitments for firm service and new service availability • Reduces transport costs during periods of elevated prices (when basis differential exceeds tariff rate)

Dual-Fuel Capability

All natural gas-fired units are capable – in theory – of dual fuel (DF) operation. However, they can differ significantly in the amount of work that would be required to establish operational DF capability and in the costs that would be incurred to establish and use DF capability. Existing facilities fall into three basic categories:

1. *Facilities that currently have DF capability* – such units require *on-going* costs to (a) actively maintain alternate fuel burners, including burner and air permit testing, and (b) maintain sufficient fuel supply for an adequate period of operation (from the perspective of reliability needs under natural gas curtailment or contingency circumstances). These annual on-going costs are estimated at roughly $1.5 million for a 260 MW facility, or $5,700 per MW. Absent market incentives to maintain this capability and a means to recover these on-going costs, DF capability has been, or likely will be, decommissioned.

2. *Facilities with decommissioned DF capability* – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs including modest technical upgrades, as needed, to bring alternate fuel burners back to operational status, as well as testing to obtain or reinstitute air permits, and to ensure burner operability. The extent of these technical upgrades likely varies across units in the ISO-NE fleet given the type of equipment and turbines, and time period since mothballing. The annualized cost of recommissioning and maintaining DF capability is roughly $2 million for a 260 MW facility, or about $6,500 per MW.
3. *Facilities with no DF capability* – such units require the same on-going costs as category 1 units, once operational. However, these units would also incur up-front costs involving major technical upgrades to add alternate fuel burners and fuel storage capability, including testing of new burners and acquiring necessary permits. The annualized cost of developing and maintaining DF capability is are estimated at roughly $4 million for a 260 megawatt (MW) unit, or about $15,000 per MW.

Table C2 presents a summary of the cost estimates and assumptions used to develop these estimates, including up-front costs, annual costs, and present value cost per kW-month. Cost estimates reflect multiple data sources, including publicly available data and data provided by ISO-NE. Results range from approximately $5,700 per MW-year for units with DF capability, to $15,000 per MW-year for units with no DF capability, including levelized capital costs of installing new infrastructure.

Table C2. Cost and Technical Assumptions Regarding Dual Fuel Capability

		Dual Fuel	
	Dual Fuel Capable	Under- or Unutilized Dual Fuel Capability	No Dual Fuel Capability
Capacity (MW)	260	260	260
Upfront Costs			
Unit Cost ($/MW)		3,600	81,000
Total Development Cost ($)		936,000	21,060,000
Testing ($)		979,050	979,050
Total Upfront Cost ($)	0	1,915,050	22,039,050
Annual Costs			
O&M ($)	200,000	200,000	200,000
Annual Testing ($)	979,050	979,050	979,050
Fuel Carrying Cost ($)	307,862	307,862	307,862
Days Fuel Supply	3	3	3
Fuel Cost ($/MMBtu)	22.8	22.8	22.8
Total Annual Costs ($)	1,486,912	1,486,912	1,486,912
Lifetime (Years)	20	20	20
Discount Rate	9%	9%	9%
Present Value ($)	13,573,340	15,488,390	35,612,390
Present Value per MW ($)	52,205	59,571	136,971
Annualized Cost per MW ($)	5,719	6,526	15,005

There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to DF capability, and differences between DF options, including the following:

- The actions needed to re-commission DF capability at units with mothballed or unused capability can likely be performed relatively quickly – burner upgrades are typically fairly limited in scope; there are relatively few barriers to securing sufficient fuel supply (other than cleaning unused storage tanks and securing cost recovery for fuel carrying costs); and minimum testing time is needed to maintain burner operability and permit status. There is more than sufficient time for resources to implement these technical changes in time for a commitment period three years ahead.
- Actions to install DF capability at units that do not have it are more involved and would require additional time – including development, permitting, and construction activities. However, there is more than sufficient time for resources to implement these technical changes prior to a commitment period three years ahead.
- In some cases there are or would be variations in output and risk of outage when actively switching from gas- to oil-firing. Some units – in particular those burning heavy fuel oil as a secondary fuel, need to power down before switching, and thus would provide less flexibility than units that can switch on the fly. In addition, there is an increased risk of outage with switching, particularly when alternate fuels are used infrequently.
- It is anticipated that regulatory limits on oil firing to address air quality concerns would generally allow for sufficient operability of DF units to cover electric system reliability needs. While some units may only be allowed to operate on oil when gas is unavailable, for most units, environmental permits typically set operational limits based on the annual number of hours operated (based on continuous operation at full output).
- Storage capacity (relative to burn at continuous full output) and storage refilling methods and rates can be an important element of maintaining resource availability, particularly during winter cold-snap conditions. DF units can have very different capacities and refill rates.
- Generally speaking, facilities served by oil pipelines or rail would be able to maintain burn if needed, and/or refill relatively quickly. But most facilities are served by truck refills, which can require days or weeks to refill to storage representing three days of continuous output.[72] For example, assuming tanker truck capacity of 9,000 gallons (generally on the high end) and representative heat rates, it would take 20 trucks per day to support continuous output of 130 MW.

[72] Three days of continuous output was chosen only to construct a representative calculation. Market performance obligations and/or reliability needs could require less than three days of continuous output.

New and Existing LNG Storage Capability

There are two options tied to liquefied natural gas that have been identified as opportunities to firm up natural gas fuel supply to natural gas-fired generating facilities in New England: (1) the construction of new land-based LNG storage facilities with liquefaction capability dedicated to providing backup gas fuel supply to power plants,[73] and (2) new services associated with spare capacity – to the extent it exists – at the two major LNG terminals serving the region (Distrigas of Massachusetts Corp, or DOMAC, located in Boston, and Canaport, located in Canada).

New LNG Storage Capacity

Estimated costs of new LNG storage capacity reflect the costs of three recently-sited facilities of roughly equal storage capacity. These facilities offered a combination of size, performance (vaporization and liquefaction), and cost that would be technically appropriate for providing backup fuel supply for gas-fired generators.

Table C3: Cost and Technical Assumptions Regarding New LNG Storage

Capacity	
LNG Volume (cubic meters)	60,000
NG Energy Capacity (MMBtu)	1,262,400
Flow capabilities	
Maximum vaporization rate (MMBtu / day)	91,300
Max MW per Day (given vaporization rate)	543
Maximum liquefaction rate (MMBtu / day)	6,333
Max MW Refill per Day (given liquefaction rate)	38
Variable Operating Costs	
Liquefaction cost ($ / MMBtu)	1.6
Storage and vaporization cost ($ / MMBtu)	0.4
Backup Fuel Supply Capability	
MW-Days of Backup Fuel Supply Stored	7,514
Max MW per Day (full output, given liquefaction rate)	543
Days to Refill (Liquefy) Sufficient Supply for Max MW per Day	14
Assumed Heat rate (Btu / kwh)	7,000

[73] With respect to new LNG storage, we focus on on-land facilities with liquefaction capability similar in size to many peak-shaving LNG storage facilities in existence today. We do not review facilities without liquefaction, as refill rates for storage without liquefaction are estimated to be too slow to provide a reliable back-up fuel supply. We also do not review new large-scale LNG terminals given the demonstrated and likely barriers to the siting of such facilities within New England.

The cost of a new LNG storage facility includes up-front development costs, annual operating costs, and the carrying cost of the stored fuel. Our estimates are based on the three facilities reviewed, sized to a generic facility with (a) a vaporization rate sufficient to provide backup fuel supply for approximately 540 MW of capacity; (b) 60,000 cubic meters (cm) of storage, equivalent to roughly 14 days of operation at the assumed vaporization rate; (c) a liquefaction rate that would be sufficient to refill enough supply to operate the facility (540 MW) for one day, in 14 days. Technical assumptions based on these three facilities are reported in Table C3.

Based on the recently-completed facilities, up-front costs range from $1,850 to $2,450 per cm of storage, amounting to approximately $128 million for the generic facility, including siting, permitting, engineering, and capital costs. Variable costs include fuel carrying costs and operating costs related to liquefaction, storage and regasification. This translates to a cost on the order of approximately $30,000 per MW-year, as shown in Table C4.

Table C4: Estimated Cost of New LNG Storage

Capacity (MW)	543
Upfront Cost	
Project cost ($)	127,666,667
Cost per cubic meter	2,128
Annual Costs	
O&M ($)	1,500,000
Carrying Cost ($)	633,920
Initial Fuel Cost (including liquefaction) ($)	7,043,561
Total Annual Costs ($)	2,133,920
PV	
Lifetime	20
Discount Rate	9%
Present Value ($)	147,146,257
Present Value per MW ($)	270,988
Annualized Cost per MW ($)	29,686

There are a number of factors related to timing, deployment, and operational characteristics that are important to consider with respect to LNG storage capability, including the following:

- Siting and development of a LNG storage facility could require multiple years, even under relatively easy siting conditions. Storage facilities of this size are modest-sized industrial facilities, so in some cases and/or locations opposition to siting at the local level could further lengthen the development timeline.
- The mix of liquefaction and vaporization rates introduces certain constraints on the market value of such facilities, and also on their reliability benefit. At the assumed (and achievable) vaporization rate, it would take between 7 and 20 days to fully discharge the tank. However, the liquefaction rate limits the ability to refill the tank after discharge. Specifically, it could take more than 190 days to fully refill the tank after discharge. Consequently, such a facility could

provide backup fuel for an extended curtailment (or multiple shorter curtailments), but that backup capability could be significantly limited for subsequent curtailments after full discharge.

Existing LNG Facilities

With respect to the existing DOMAC and Canaport facilities, it has been suggested that backup fuel supply to electric generators could be provided through arrangements to essentially store fuel and inject it into the pipelines upon request by electric generators from these two facilities.[74] Reliance on such services would require excess storage and regasification capacity at the terminal in question, and delivery service on Algonquin or Tennessee to the gas-fired generator's connection point on the pipelines. In addition, for Canaport service there would need to be delivery service on the Maritimes and Northeast pipeline. The stored gas, and the capacity to inject and deliver it, would need to be available as and when needed by the gas generator.

In this case, there are essentially no up-front costs. All services would be on existing facilities to the extent capacity exists. An estimate of annual costs can be derived by estimating (1) the opportunity cost of storing LNG instead of selling it in higher-value markets (i.e., Europe); (2) the carrying cost reflecting interest on the value of stored fuel; (3) the operating cost required to cool and store LNG at the facilities (including any lost fuel due to "boil off") and (4) if firm service is required to meet reliability requirements, a transportation charge for moving gas from storage to delivery point.

We have not attempted to estimate the type and cost of pipeline transportation charges, given the uncertainty around the type of service and rate that would be charged within the constraints of existing pipeline capacity. We have also not attempted to estimate the cost associated with service from existing LNG facilities due to uncertainty about the avoidable variable costs of storing incremental quantities of LNG supplies for use by gas-fired generators, and uncertainty about the rates the LNG facilities would charge for storage and release service for gas-fired generators. These rates would be subject to negotiations between generators and existing LNG facilities, which would reflect many factors, including the next-best options available to generators to storage and release service from an existing LNG facilities (such as foregoing service or developing dual fuel capability). Public information provided by existing LNG facilities on illustrative costs of such service suggests that this service would be more expensive than incremental development of dual fuel capability.[75] To the extent that resources can obtain service at terms that are less costly than dual fuel capability, the estimates of the quantity of incremental resources that address fuel dependency risks as a result of FCM PI would tend to be understated.

[74] In theory, these same services could be supplied by the offshore Neptune and Northeast Gateway terminals, through tankers "parked" at the intake pipes, or from existing local gas distribution company (LDC) peak shaving storage capacity. However, we did not review this separately given the potentially prohibitive costs of using tankers (on top of the other costs that would be faced by Canaport or DOMAC), and given the dedication of LDC storage facilities to serve natural gas LDC customers on peak.

[75] For example, see the illustrative terms and conditions for Call Option Service from the Canaport Facility provided by Repsol. Vince Morrisette, Repsol, "Gas Supply Peaking Option from Canaport LNG," ISO-NE Markets Committee, May 13, 2013.

New Interstate Pipeline Capacity

Relatively little firm service is available on the primary pipelines serving New England, so additional firm natural gas supply will likely require the construction of additional pipeline capacity. Increased natural gas pipeline capacity could support the transport of additional fuel supplies to the region, and so would reduce the risk of curtailment to gas-fired generators, relative to current market conditions. Additional pipeline capacity to provide firm gas supply can be achieved through various changes to the interstate pipeline system to relieve pipeline congestion or add incremental capacity, ranging from new compressor stations along existing pipe, to looping, to the construction of new pipelines from key gas sources (e.g., the Marcellus Shale region). The cost of various changes are difficult to identify absent engineering studies, and depend on the extent to which lower-cost technical changes to expand the capacity of the existing pipeline assets have already been exhausted.

The range of potential upfront costs to increase pipeline capacity from Marcellus and other lower-cost natural gas reserve regions is wide, and depends on the location of constraints being relieved, and/or the overall size and route of the project. Figure C2 provides estimates of the underlying capital costs of recently developed pipelines in the New England region in terms of the dollars per MW of firm service to gas-fired electricity generators. In addition to up-front costs, annual costs are incurred for operations and maintenance on the pipeline system. This estimate, based on an assumed increase in pipeline capacity of nearly 400,000 dekatherms per day, is approximately $1.17/kW-mth of equivalent electrical generating capacity.

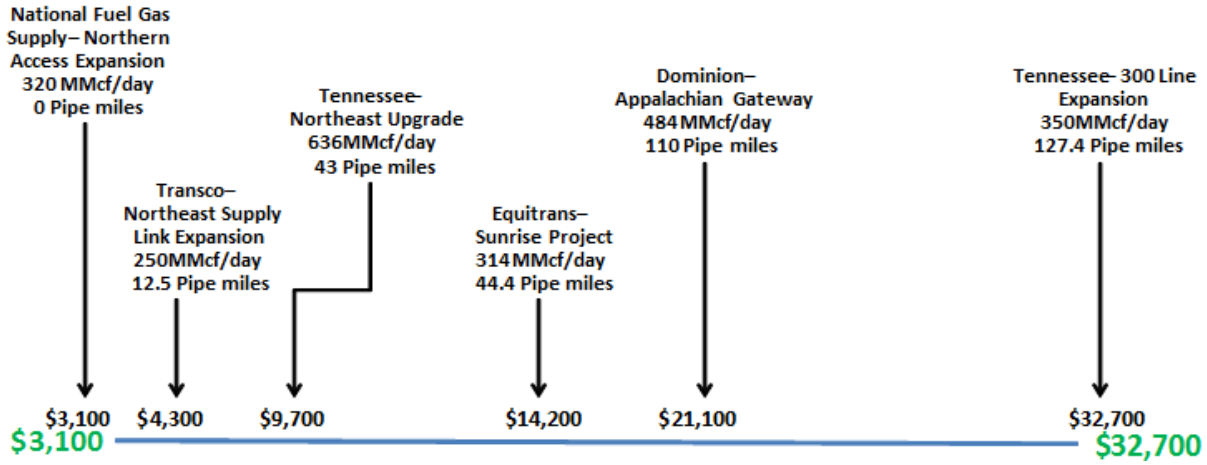
Ignoring the expansion projects, the annualized cost of upfront capital investments ranges from $9,700 per MW to $32,700 per MW (reflecting generation at a heat rate of 7,000 BTU per kw). These costs are comparable to those estimated by Black and Veach in a recent study for the New England States Committee on Electricity (NESCOE).[76] Total costs would account for additional factors such as annual operating expenditures.

Costs in Figure C2 do not reflect the rates that would be charged to generators for firm service. These rates would be higher than the costs reflected in these tables due to a variety of factors such as annual expenditures included in rates, differences in discount rates, and delays between when costs are incurred and when cost recovery begins from pipeline construction. Cost estimates also do not reflect potential reduction in gas transportation costs during periods of tight gas supply, particularly when the basis differential exceeds the tariff rate, or the ability of new pipeline to lower power system costs during such periods when supply from such regions would otherwise be constrained.

Assuming actual project costs would be toward the upper end of costs represented in Figure C2, and considering differences between estimates of annualized upfront costs and actual rates charged for firm service, we conclude that firm service on new pipelines is likely to be a more costly option for market participants to address gas dependency risks. To the extent that resources can obtain firm service at rates that are less costly than dual fuel capability, the estimates of the quantity of incremental resources that address fuel dependency risks as a result of FCM PI would tend to be understated.

[76] Black & Veatch, "New England Natural Gas Infrastructure and Electric Generation: Constraints and Solution", prepared for the New England States Committee on Electricity, April 16, 2013.

Figure C2: Capital Costs of Recent Northeast Pipeline Projects



There are a number factors related to timing, deployment, and operational characteristics that are important to consider with respect to the reliability and economic value of increasing pipeline capacity, including the following:

- The timeline for new pipeline capacity siting, permitting, and construction is on the order of several years. Consequently, this is not an option that can provide meaningful power system reliability benefits for at least several years.
- Under current FERC rules and past practices for funding new pipeline capacity, new projects typically will not go forward without up-front financial commitments from customers to take firm delivery service for all – or most – of the new capacity. Entering into such long-term financial commitments for natural gas transportation is challenging for electric generators under current market conditions.
- Current pipeline capacity firm commitments are held almost entirely by natural gas local distribution companies (LDCs) for the benefit of natural gas ratepayers, and with the guarantee that such capacity will be used to meet the need of LDC end-use customers for heating and process needs as necessary, particularly at the time of winter peak conditions. This means that while substantial amounts of such capacity may be released to secondary markets for use by electric generators throughout the year, it cannot be counted on during winter peak or cold-snap conditions.

List of Sources Reviewed for Appendix C

Sources of information relied on for the Dual Fuel section include the following:

- ESS Group, "Dual-Fuel Generating Capacity and Environmental Constraints Analysis," Interim Report, prepared for ISO-NE, April 1, 2005.
- Conversations with ISO-NE staff.
- Settlement between NYISO and TransCanada, Ravenswood for recovery of on-going costs of maintaining dual fuel capability, April 2011.
- PJM Cost of New Entry (CONE), incremental cost for dual fuel capability on new generation units, 2011.
- Handy-Whitman Index of Public Utility Construction Costs.
- Analysis Group estimates based on these reports, and on data provided by ISO-NE.

Sources of information relied on for the New Interstate Pipeline section include the following:

- INGAA publication #17742 (sourced from North American Midstream Infrastructure Through 2035 – A Secure Energy Future, ICF International for INGAA, June 28, 2011).
- "2012 Worldwide Pipeline Construction Report," Pipeline & Gas Journal, January 2012.
- "Pipeline Costs in Shale Gas Regions," Ziff Energy Group, June 29, 2011; "Natural Gas Under Siege," Ziff Energy Group, April 2012.
- "Gas and Electric Infrastructure Interdependency Analysis," Prepared for MISO by EnVision Energy Solutions, February 2012.
- "Jobs & Economic Benefits of Midstream Infrastructure Development, US Economic Impacts Through 2035," Black & Veatch for INGAA, February 15, 2012.
- Black & Veach, "New England Natural Gas Infrastructure and Electric Generation: Constraints and Solution", prepared for the New England States Committee on Electricity, April 16, 2013.

Sources of information relied on for the LNG Storage section include the following:

- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009.
- UGI LNG company website: http://www.ugilng.com/
- "LNG Facility Brings Positive Economic Change to Former Manufacturing Center," Pipeline & Gas Journal, November 2009.
- "LNG Peakshaving Facility, Connecticut, USA," CB&I company website, http://www.cbi.com/markets/project-profiles/lng-peakshaving-facility-connecticut-usa/
- "Mt. Hayes Liquefied Natural Gas Storage Facility, Terasen Gas (Vancouver Island) Inc.," Stakeholder Workshop for the CPCN Application, June 27, 2007.

- "Mt. Hayes LNG Storage Facility – In the Matter of an Application by Terasen Gas (Vancouver Island) In. for a Certificate of Public Convenience and Necessity," Submitted to British Columbia Utilities Commission, June 5, 2007".
- "West Coast LNG Projects and Proposals," California Energy Commission, Sept. 2011.
- "CB&I Awarded Contract for Temple LNG Expansion Project," Pipeline & Gas Journal, December 2009.
- Repsol, "A Potential LNG Solution for Maintaining Pipeline Deliverability During Peak Demand Periods," ISO NE / NGA Meeting, April 12, 2012.
- Vince Morrisette, Repsol, "Gas Supply Peaking Option from Canaport LNG," ISO-NE Markets Committee, May 13, 2013.
- EIA, "World LNG Shipping Capacity Expanding," Report #DOE/EIA-0637, 2003.
- Massachusetts gas utility resource plans and forecasts.
- Analysis Group estimates.

Attachment I-1h

The ISO's blacklined Tariff sheets effective June 1, 2014

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:

Actual Load is the consumption at the Retail Delivery Point for the hour.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of 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.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. The daily bid Blocks in the price-based Real-Time bid will be multiplied by the number of hours in the day 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 risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

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 generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand 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 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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 CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a

Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision 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 compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

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 under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's 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 the day); (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 (for Capacity Commitment Periods commencing on or after June 1, 2017, 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.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on January 17, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22 and Schedule 23 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 Clearing Price Floor is described in Section III.13.2.7.

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, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 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 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 is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on January 17, 2014.

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 Requirement is described in Section III.13.7.3.1 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-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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.

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.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A 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.

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 power year, 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 in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of 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 Generating Capacity 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.

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.

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 value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

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 Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation 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 Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time

Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

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 Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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 the pumping load associated with pumped storage generators) 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 the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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 or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response 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.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start 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 time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation 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) is the Dispatch Rate expressed in megawatts.

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 Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource's or contract's Supply Offer or Demand Bid 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 Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and 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 Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or below the Dynamic De-List Bid Threshold~~prices of $1.00/kW-month or lower~~, 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 Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to 68 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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 generation amount, in MWs, that a generating unit 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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II 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 hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

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 and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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, the Capacity Requirement 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.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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 by 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, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 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 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.

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.

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 Generator means a generating unit that the ISO may dispatch within the hour 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) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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.

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 Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as 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 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 $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance

with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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 generator that has been registered 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 Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

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.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) 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 generation 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.

Insufficient Competition is defined in Section III.13.2.8.2 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures" or the "Small Generator Interconnection Procedures" pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

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 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.

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.

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 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.

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 or Demand Bids 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 generating resources 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.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand

Response Event Hours to other hours and reduce the amount of capacity needed, 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, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service

with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local 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 the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

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 or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered

demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

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 a 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 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 Value of the Demand 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 Value for an Existing Demand Resource is not over-

stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand 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, which includes 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 a Demand Resource supplier 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 Demand Resource suppliers 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 Value of the 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 a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all 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.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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 Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

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 as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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 Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a

resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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.

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.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

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 generating unit that must be paid to Market Participants with an Ownership Share in the unit 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 generating unit 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.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

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-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-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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.

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 generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and 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 between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand 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 generating unit asset or Load Asset, where such unit or load 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.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 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 II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

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.

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(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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 Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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 or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

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.

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.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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.

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 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)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when

deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, 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(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) 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 Price Response Program is the program described in Appendix E 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.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation 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 adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of 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.5.6.1 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 an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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.

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, for Capacity Commitment Periods commencing on or after June 1, 2017, 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 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.

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 generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the

Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand 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.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii)

for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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 generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand 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 risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

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. 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.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 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. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day 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, or Schedule 23 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.

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 the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

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) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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 O&M Payment is the annual compensation calculated under either Section 5.1 or 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 Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

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 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 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.

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 Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource 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 Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. 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.

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III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load 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.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors 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 generator 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 generation 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. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, 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. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. 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 locational 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 most recent power flow solution produced by the State Estimator, 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 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of 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.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal 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 most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section

III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, 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 generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy 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; (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 generation 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.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. 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.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding 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 zero for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to zero for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal 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 and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, 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 bid 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; (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 generation 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 generation. The 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 Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, 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 generation at its Economic Maximum Limit, 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 $1,000/MWh;

(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 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 generation, 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 generation, 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 generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation 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 $0/MWh and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation 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 generation; and

(iii) If power balance not achieved in step (ii), set LMP values to zero and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

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 for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load 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 and Reserve Zones and add or subtract Reliability Regions, Load 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. 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 determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, 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 generating Resources and Dispatchable Asset Related Demand Resources 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 create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation

Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource's output necessary to create the additional Operating Reserve or local TMOR from the generating Resource's expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		$250/MWh
System TMOR	minimum TMOR	$500/MWh
	Replacement Reserve	$250/MWh
System TMNSR		$850/MWh
System TMSR		$50/MWh

The RCPFs 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 every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding 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 to be used in settlements.

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 hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as

practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post

final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.1.2.2.4.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The

$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.
For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.
For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project

Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website.

A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff.

A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option,

exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail

to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource

shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation,

then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource's summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section

III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period

associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation~~opt out of the capacity market~~ at prices at or above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~ during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not

result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation~~opt out of the capacity market~~ permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~ are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~ are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing

Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if: (1) at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

(a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of summer Qualified Capacity of all Existing Capacity Resources will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~ to determine whether the bid is consistent with: (1) the Existing Generating Capacity Resource's net ~~risk-adjusted~~ going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2~~1~~); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5~~2~~). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the

Internal Market Monitor to make such determinations. ~~Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary.~~ The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs, ~~and~~ the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions,

and reasonable opportunity costs~~net risk-adjusted going forward and opportunity costs~~, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, ~~I~~if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward and opportunity costs~~, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk- adjusted going forward costs and opportunity costs~~ as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward costs and opportunity costs~~. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described

in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

~~(a)~~(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward and opportunity costs~~, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold~~$1.00/kW-month~~. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold~~$1.00/kW-month~~.

~~(b)~~(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in

Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward and opportunity costs~~, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward costs and opportunity costs~~ as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward costs and opportunity costs~~ as determined by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward costs and opportunity costs~~. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~.

III.13.1.2.3.2.1.2. Net ~~Risk-Adjusted~~ Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~, or Permanent De-List Bid above the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~ shall be considered consistent with the Existing Generating Capacity Resource's net ~~risk-adjusted~~ going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{\left[GFC - IMR - PER\right] \times InfIndex}{CQ_{Summer}, kw \times 12, months}$$

$$\frac{\left(\left[GFC / AA\right] + \left[RF\right] + \left[IMR - PER\right]\right) \times InfIndex}{\left(CQ_{Summer}, kw\right) \times \left(12, months\right)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be

incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

$CQ_{Summer}kW$ = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

~~RF = risk factor, in dollars. This value shall be calculated using the following formula:~~

~~RF = [(RPC x EFORd) + (P x (Forward Capacity Auction Starting Price – AFCAP) x 12,months)] x $CQ_{Summer}kW$~~

~~Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.~~

~~EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.~~

~~RPC = replacement power costs rate, in dollars/kW. As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit's daily price to the resource's Real-Time nodal price. For each hour that the resource's nodal price exceeds the PER Proxy Unit's daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit's daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.~~

~~P = Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period. This estimate shall be no greater than the~~

~~EFORd of the resource for the corresponding period used in quantifying going forward costs, and in no case greater than 0.40. The Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.~~

~~AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward Capacity Auction clearing prices in the resource's Capacity Zone.~~

~~AA = availability adjustment. AA = (1 – EFORd)~~

~~Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.~~

~~EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.~~

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid),this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for

each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland~~1 Year Constant Maturity Treasury Rate~~ at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5~~3~~. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold~~$1.00/kW-month~~, or Permanent De-List Bid above the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~ has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid~~support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1~~, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. ~~Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost.~~ Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification. ~~The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).~~

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer

Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{CostOfCapital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:
Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. ~~Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).~~ Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor's review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net ~~risk-adjusted~~ going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package

submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	**Maine**
HQ Phase I/II External Node	**Rest-of-Pool**
Highgate External Node	**Rest-of-Pool**
NY-NE AC External Node	**Rest-of-Pool**
Cross Sound Cable External Node	**CT**

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in

Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	**MW**	**Contract End Date**
NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is

located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-

Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of

overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be

located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource

Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the

relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail

regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after

the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c)

and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~ or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including

the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs

incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in yer "X", where X is any year after 2015.

New Capacity Show of Interest Submission Window	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Purchased in Each Forward Capacity Auction.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price

associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a "New Capacity Offer") indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \ldots \quad \ldots & , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource's summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of

that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold~~$1.00/kW-month~~, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~. Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold ~~$1.00/kW-month~~ (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold~~$1.00/kW-month~~) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5,

and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the "Total System Capacity") shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones

modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone's Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface's approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone's Local Sourcing Requirement; or

(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two

conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**. For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone's Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources

and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient

Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but

the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. For de-list bids, this review and update will follow

ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Permanent De-List Bid as accepted for the Forward Capacity Auction. Cost-of-service agreements must be filed with and approved by the Commission, and

cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-

service rates for the unit in question or has accepted subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by ISO New England**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(c), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]

III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that

price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone's Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource's location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9 Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.

The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.

If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.

In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.

III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, "New Capacity Required" shall mean the Capacity Zone's Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, "New Capacity Required" shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone's Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the

Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant's total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. For purposes of this Section III.13.2.8.2, a~~A~~ Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant's potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor's

determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids from resources associated with pivotal Lead Market Participants as described in Section III.13.1.2.3.2 based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs~~net risk-adjusted going forward costs and opportunity costs~~ as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be

conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3. [Reserved.]

III.13.8.4. [Reserved.]

Attachment I-1i

The ISO's clean Tariff sheets effective June 1, 2014

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:

Actual Load is the consumption at the Retail Delivery Point for the hour.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of 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.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. The daily bid Blocks in the price-based Real-Time bid will be multiplied by the number of hours in the day 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 risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

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 generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand 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 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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 CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a

Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision 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 compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

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 under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's 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 the day); (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 (for Capacity Commitment Periods commencing on or after June 1, 2017, 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.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on January 17, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22 and Schedule 23 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 Clearing Price Floor is described in Section III.13.2.7.

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, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 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 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 is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on January 17, 2014.

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 Requirement is described in Section III.13.7.3.1 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-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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.

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.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A 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.

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 power year, 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 in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of 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 Generating Capacity 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.

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.

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 value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

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 Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation 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 Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time

Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

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 Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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 the pumping load associated with pumped storage generators) 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 the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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 or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response 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.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start 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 time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation 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) is the Dispatch Rate expressed in megawatts.

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 Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource's or contract's Supply Offer or Demand Bid 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 Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and 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 Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or 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 Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to 68 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related

Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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 generation amount, in MWs, that a generating unit 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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II 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 hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

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 and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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, the Capacity Requirement 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.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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 by 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, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 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 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.

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.

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 Generator means a generating unit that the ISO may dispatch within the hour 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) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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.

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 Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as 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 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 $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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 generator that has been registered 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 Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

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.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) 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 generation 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.

Insufficient Competition is defined in Section III.13.2.8.2 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures" or the "Small Generator Interconnection Procedures" pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

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 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.

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.

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 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.

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 or Demand Bids 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 generating resources 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.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, 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, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local 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 the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

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 or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss

Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered

demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

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 a 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 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 Value of the Demand 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 Value for an Existing Demand Resource is not over-

stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand 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, which includes 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 a Demand Resource supplier 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 Demand Resource suppliers 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 Value of the 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 a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all 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.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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 Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

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 as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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 Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a

resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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.

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.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

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 generating unit that must be paid to Market Participants with an Ownership Share in the unit 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 generating unit 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.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

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-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-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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.

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 generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and 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 between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand 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 generating unit asset or Load Asset, where such unit or load 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.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 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 II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

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.

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(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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 Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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 or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

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.

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.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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.

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 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)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when

deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, 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(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) 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 Price Response Program is the program described in Appendix E 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.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation 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 adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of 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.5.6.1 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 an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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.

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, for Capacity Commitment Periods commencing on or after June 1, 2017, 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 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.

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 generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the

Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand 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.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii)

for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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 generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand 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 risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

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. 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.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 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. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day 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, or Schedule 23 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.

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 the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

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) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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 O&M Payment is the annual compensation calculated under either Section 5.1 or 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 Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

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 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 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.

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 Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource 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 Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. 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.

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III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load 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.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors 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 generator 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 generation 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. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, 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. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. 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 locational 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 most recent power flow solution produced by the State Estimator, 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 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of 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.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal 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 most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section

III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, 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 generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy 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; (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 generation 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.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. 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.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding 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 zero for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to zero for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal 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 and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, 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 bid 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; (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 generation 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 generation. The 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 Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, 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 generation at its Economic Maximum Limit, 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 $1,000/MWh;

(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 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 generation, 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 generation, 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 generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation 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 $0/MWh and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation 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 generation; and

(iii) If power balance not achieved in step (ii), set LMP values to zero and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

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 for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load 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 and Reserve Zones and add or subtract Reliability Regions, Load 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. 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 determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, 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 generating Resources and Dispatchable Asset Related Demand Resources 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 create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation

Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource's output necessary to create the additional Operating Reserve or local TMOR from the generating Resource's expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		$250/MWh
System TMOR	minimum TMOR	$500/MWh
	Replacement Reserve	$250/MWh
System TMNSR		$850/MWh
System TMSR		$50/MWh

The RCPFs 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 every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding 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 to be used in settlements.

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 hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as

practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post

final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.1.2.2.4.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The

$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.
For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.
For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project

Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website.

A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff.

A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option,

exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail

to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource

shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation,

then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource's summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section

III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period

associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.A Dynamic De-List Bid Threshold.

The Dynamic De-List Bid Threshold beginning with the ninth Forward Capacity Auction (for the Capacity Commitment Period beginning on June 1, 2018) shall be $3.94/kW-month. The Dynamic De-List Bid Threshold shall be recalculated no less often than once every three years. When the Dynamic De-List Bid Threshold is recalculated, the Internal Market Monitor will review the results of the recalculation with stakeholders and the new Dynamic De-List Bid Threshold shall be filed with the Commission under Section 205 of the Federal Power Act prior to the Existing Capacity Qualification Deadline for the associated Forward Capacity Auction.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to specify a price below which it would not accept a Capacity Supply Obligation at prices at or above the Dynamic De-List Bid Threshold during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being

less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to specify a price below which it would not accept a Capacity Supply Obligation permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above the Dynamic De-List Bid Threshold are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing

Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

For purposes of this Section III.13.1.2.3.2, a Static De-List Bid, Permanent De-List Bid, or Export Bid shall be associated with a pivotal supplier if: (1) at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the New England Control Area minus the Installed Capacity Requirement (net of HQICCs) is less than or equal to the greater of:

(a) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 200 MW;

or (2) where the bid is associated with a resource in an import-constrained Capacity Zone, if at the Forward Capacity Auction Starting Price, the total amount of summer Qualified Capacity of all Existing Capacity Resources in the import-constrained Capacity Zone minus the Local Sourcing Requirement for the import-constrained Capacity Zone is less than or equal to the greater of:

(a) the amount of capacity from all Existing Capacity Resources in the import-constrained Capacity Zone controlled by the Lead Market Participant for the resource submitting the bid multiplied by 1.1; and

(b) the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource submitting the bid plus 100 MW.

In making this determination, the total amount of summer Qualified Capacity of all Existing Capacity Resources will be reduced by an amount equal to the total of all pending Non-Price Retirement Requests and Permanent De-List Bids other than those submitted by the Lead Market Participant for the resource being evaluated, and the amount of capacity from all of the Existing Capacity Resources controlled by the Lead Market Participant for the resource will include any capacity subject to a pending Non-Price Retirement Request or Permanent De-List Bid. The determination whether a Lead Market Participant is pivotal will be included in the qualification determination notification described in Section III.13.1.2.4. If the applicable Installed Capacity Requirement (net of HQICCs) and Local Sourcing Requirement are not finalized at the time that the Internal Market Monitor must make this determination, then the Internal Market Monitor shall use the best available estimates of those values available at that time, and shall publish those estimated values to the ISO website no later than the date that the qualification determination notifications are issued.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above the Dynamic De-List Bid Threshold, and Permanent De-List Bids Above the Dynamic De-List Bid Threshold.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above the Dynamic De-List Bid Threshold, and each Permanent De-List Bid above the Dynamic De-List Bid Threshold to determine whether the bid is consistent with: (1) the Existing Generating Capacity Resource's net going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.2); (2) reasonable expectations about the resource's Capacity Performance Payments (as determined pursuant to Section III.13.1.2.3.2.1.3); (3) reasonable risk premium assumptions (as determined pursuant to Section III.13.1.2.3.2.1.4); and (4) the resource's reasonable opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.5). Sufficient documentation and information about each of these bid components must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to

the accuracy of the reported costs, the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and the reasonableness of the expectations and assumptions regarding Capacity Performance Payments and risk premiums, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant (including information about the the other existing or potential new resources controlled by the Lead Market Participant) after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate. The Internal Market Monitor shall review all relevant information (including data, studies, and assumptions) to determine whether the bid is consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. In making this determination, the Internal Market Monitor shall consider, among other things, industry standards, market conditions (including published indices and projections), resource-specific characteristics and conditions, portfolio size, and consistency of assumptions across that portfolio.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

(a) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(b) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

(c) In the case of a Permanent De-List Bid or an Export Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due

consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1(c), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold .

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be not pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold.

Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(b) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold.

(c) In the case of a Static De-List Bid from a resource associated with a Lead Market Participant that is found to be pivotal by the Internal Market Monitor pursuant to the determination described in Section III.13.1.2.3.2, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net going forward costs, reasonable

expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor and greater than the Dynamic De-List Bid Threshold . Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below the Dynamic De-List Bid Threshold .

III.13.1.2.3.2.1.2. Net Going Forward Costs.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall report net going forward costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. A Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold , or Permanent De-List Bid above the Dynamic De-List Bid Threshold shall be considered consistent with the Existing Generating Capacity Resource's net going forward costs based on a review of the data submitted in the following formula. To the extent possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{\left[GFC - \ IMR - PER \ \right] \times InfIndex}{CQ_{Summer}, kw \ \times \ 12, months}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

CQ_{Summer}kW = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid),this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of

a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 4-Year expected inflation number published by the Federal Reserve Bank of Cleveland at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Expected Capacity Performance Payments.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing the expected Capacity Performance Payments for the resource. This documentation must include expectations regarding the applicable Capacity Balancing Ratio, the number of hours of reserve deficiency, and the resource's performance during reserve deficiencies.

III.13.1.2.3.2.1.4. Risk Premium.

The Lead Market Participant for an Existing Generating Capacity Resource that submits a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold that is to be reviewed by the Internal Market Monitor shall also provide documentation separately detailing any risk premium included in the bid. This documentation should

address all components of physical and financial risk reflected in the bid, including, for example, catastrophic events, a higher than expected amount of reserve deficiencies, and performing scheduled maintenance during reserve deficiencies. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net going forward costs described in Section III.13.1.2.3.2.1.2 may be included in this risk premium component. In support of the resource's risk premium, the Lead Market Participant may also submit an affidavit from a corporate officer attesting that the risk premium submitted is the minimum necessary to ensure that the overall level of risk associated with the resource's participation in the Forward Capacity Market is consistent with the participant's corporate risk management practices.

III.13.1.2.3.2.1.5. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above the Dynamic De-List Bid Threshold, or Permanent De-List Bid above the Dynamic De-List Bid Threshold has additional opportunity costs that are not reflected in the net going forward costs, expected Capacity Performance Payments, or risk premium components of the bid, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification.

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{Cost\ Of\ Capital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid including a determination whether the Lead Market Participant is pivotal as described in Section III.13.1.2.3.2 and indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor's review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward

Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	**Maine**
HQ Phase I/II External Node	**Rest-of-Pool**
Highgate External Node	**Rest-of-Pool**
NY-NE AC External Node	**Rest-of-Pool**
Cross Sound Cable External Node	**CT**

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous

Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed.

For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	**MW**	**Contract End Date**
NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or controlled directly by the Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or

curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand

Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New

England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the

monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation

by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form. A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5

Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is

separately metered and its output is added to the metered load as measured at the Retail Delivery Point. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project

Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and

Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO

determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a

Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail

regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after

the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c)

and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above the Dynamic De-List Bid Threshold or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including

the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs

incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in yer "X", where X is any year after 2015.

New Capacity Show of Interest Submission Window	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Purchased in Each Forward Capacity Auction.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price

associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a "New Capacity Offer") indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \ldots \quad \ldots & , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource's summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of

that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below the Dynamic De-List Bid Threshold, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below the Dynamic De-List Bid Threshold . Such a bid shall be defined by the submission of one to five prices, each less than the Dynamic De-List Bid Threshold (or the Start-of-Round Price, if lower than the Dynamic De-List Bid Threshold) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same

manner as Static De-List Bids as described in Section III.13.2.3.2(b). Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the "Total System Capacity") shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones

modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone's Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface's approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone's Local Sourcing Requirement; or

(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two

conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**. For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone's Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources

and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient

Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but

the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. For de-list bids, this review and update will follow

ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Permanent De-List Bid as accepted for the Forward Capacity Auction. Cost-of-service agreements must be filed with and approved by the Commission, and

cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-

service rates for the unit in question or has accepted subject to refund while the rate is reviewed. In no event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by ISO New England**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(c), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]

III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that

price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone's Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource's location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9 Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.

The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.

If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.

In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.

III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, "New Capacity Required" shall mean the Capacity Zone's Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, "New Capacity Required" shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone's Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the

Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant's total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. For purposes of this Section III.13.2.8.2, a Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant's potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor's

determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids from resources associated with pivotal Lead Market Participants as described in Section III.13.1.2.3.2 based on the Internal Market Monitor review and the resource's net going forward costs, reasonable expectations about the resource's Capacity Performance Payments, reasonable risk premium assumptions, and reasonable opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the

Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3. **[Reserved.]**

III.13.8.4. **[Reserved.]**

Attachment I-1j

List of New England Governors and Utility Regulatory Agencies

New England Governors, State Utility Regulators and Related Agencies

Maine

The Honorable Paul LePage
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Kathleen.Newman@maine.gov

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018
Maine.puc@maine.gov

New Hampshire

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Meredith.Hatfield@nh.gov

New Hampshire Public Utilities Commission
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Vermont

The Honorable Peter Shumlin
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Vermont Department of Public Service
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Massachusetts

The Honorable Deval Patrick
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Massachusetts Department of Public Utilities
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Rhode Island

The Honorable Lincoln Chafee
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Rhode Island Public Utilities Commission
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Connecticut

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ATTACHMENT N-1a

Transmittal letter on behalf of NEPOOL

NEW ENGLAND POWER POOL

January 17, 2014

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

Re: ISO New England Inc. and New England Power Pool, Docket No. ER14-___-000;
NEPOOL Proposed Revisions to Market Rule 1 of the ISO-NE Tariff

Dear Secretary Bose:

The New England Power Pool ("NEPOOL")[1] Participants Committee[2] hereby submits for inclusion in a joint filing with ISO New England Inc. ("ISO-NE") NEPOOL-approved revisions to the Market Rules to add two incremental capacity and energy/reserve market changes. These changes are designed specifically to complement and enhance a myriad of performance incentive-related changes already implemented or pending in the New England energy and operating reserve markets. NEPOOL's proposed Market Rule revisions (the "NEPOOL Proposal") are an alternative and preferred set of revisions to Market Rule changes proposed by ISO-NE (the "ISO-NE Proposal"), which seeks to implement an entirely new and unproven Forward Capacity Market ("FCM") economic construct as separately described by ISO-NE in its transmittal letter and supporting materials.

[1] Capitalized terms not defined herein have the meanings ascribed thereto in the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO-NE Transmission, Markets and Services Tariff (the "ISO-NE Tariff"). Section III of the ISO-NE Tariff is referred to as "Market Rule 1."

[2] NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 430 members. The Participants include all of the electric utilities rendering or receiving services under the ISO-NE Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers, developers, end users, and independent transmission company and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission in *ISO New England Inc. et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, NEPOOL provides the sole Participant Process for advisory voting on ISO-NE matters and the selection of ISO-NE Board members, except for input from state regulatory authorities and as otherwise may be provided in the ISO-NE Tariff, TOA and the Market Participant Services Agreement included in the ISO-NE Tariff.

Both proposals seek to further address existing reliability, investment and resource performance challenges in New England. However, the two proposals offer fundamentally different approaches. ISO-NE seeks in the ISO-NE Proposal to redefine capacity as a very different product where payments are affected dramatically by whether a resource is providing energy and/or operating reserves in Real-Time three years hence. In so doing, ISO-NE seeks to fundamentally change the nature of the capacity market construct in New England through its new and untested "pay-for-performance" mechanism. ISO-NE's proposal abandons longstanding capacity market principles in New England and the other RTO markets and converts the FCM from a market designed to ensure long-term resource adequacy to one that is driven primarily by prospective and largely unpredictable actual production. Resources that are not producing energy or reserves at the time of a "Capacity Scarcity Condition" for any reason will be subject to significant penalties, even if that scarcity condition occurs during very low load conditions, or is caused by transmission outages or even by errors in ISO-NE's load forecasting. In contrast, the NEPOOL Proposal, building upon a series of Market Rule changes that either have been made or are pending, proposes moderate but important changes that would enhance the current market design and achieve the objective of improving the performance incentives for resources in the ISO-NE electricity markets.

In addition to this transmittal letter, NEPOOL also offers the following in support of its proposal:[3]

- Attachment N-1b -- Testimony of Peter D. Fuller, Director of Regulatory Affairs, NRG Energy Inc., East Region, on behalf of NEPOOL (the "Fuller Testimony");
- Attachment N-1c -- Testimony of Calvin A. Bowie, Manager - NEPOOL and ISO Relations, Northeast Utilities, on behalf of NEPOOL (the "Bowie Testimony");
- Attachment N-1d -- Testimony of Brian E. Forshaw, Chief Regulatory and Risk Officer, Connecticut Municipal Electric Energy Cooperative, on behalf of NEPOOL (the "Forshaw Testimony");
- Attachment N-1e -- Testimony of Elin S. Katz, Consumer Counsel, Connecticut Office of Consumer Counsel, on behalf of NEPOOL (the "Katz Testimony");
- Attachment N-1f -- Affidavit and Report of Richard D. Tabors, Ph.D., on behalf of NEPOOL;
- Attachment N-1g -- Summary of NEPOOL Stakeholder Process;

[3] NEPOOL Participants register their individual positions through votes on NEPOOL matters and, if they wish, through further explanations of their views during the stakeholder process. NEPOOL's positions are defined by the voting results. The affidavits/testimony reflect the views of their respective companies and do not reflect in all instances the positions or opinions of all NEPOOL Participants.

- Attachment N-1h -- A tabulation of the NEPOOL votes taken on the NEPOOL and ISO-NE Proposals at the December 6, 2013 NEPOOL Participants Committee meeting;
- Attachment N-1i -- Blacklined Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective June 1, 2014;
- Attachment N-1j -- Clean Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective June 1, 2014;
- Attachment N-2b -- Blacklined Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective June 1, 2018; and
- Attachment N-2c -- Clean Tariff sheets containing NEPOOL's proposed revisions to the Tariff to become effective June 1, 2018.

I. JUMP BALL STANDARD

The governance arrangements negotiated and approved in order for ISO-NE to assume the role of the regional transmission organization in New England provide for a "jump ball" filing under Section 11.1.5 of the Participants Agreement when ISO-NE and NEPOOL approve alternative proposed changes to the Market Rules. Section 11.1.5 requires ISO-NE to make a "jump ball" filing when NEPOOL supports by at least a 60% Vote of the Participants Committee a Market Rule change that is different than an ISO-NE proposed Market Rule change. In a "jump ball" filing, the NEPOOL proposal is filed at the same time and on the same footing as ISO-NE's proposal (i.e., under Section 205 of the Federal Power Act). The Commission is not constrained by the requirement that it must accept the ISO-NE proposal if it is demonstrated to be just and reasonable, but rather is given the latitude to "adopt any or all of [ISO-NE]'s Market Rule proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable."[4]

[4] Participants Agreement at Section 11.1.5. Section 11.1.5 of the Participants Agreement provides in its entirety as follows:

> If the Participants Committee vote relating to an [ISO-NE] Market Rule proposal results in the approval by the Participants Committee by a Participants Vote equal to or greater than 60% of a Market Rule proposal that is different from the one proposed by [ISO-NE], including, but not limited to, a Governance Participant proposal, [ISO-NE] shall, as part of any required Section 205 filing, describe the alternate Market Rule proposal in detail sufficient to permit reasonable review by the Commission, explain [ISO-NE]'s reasons for not adopting the proposal, and provide an explanation as to why [ISO-NE] believes its own proposal is superior to the proposal approved by the Participants Committee. The Commission will not be required to consider whether the then-existing filed rate is unlawful, and may adopt any or all of [ISO-NE]'s Market Rule

Thus, the jump ball provision expands the more limited authority of the Commission that constrains its actions in response to a more traditional filing under Section 205. In a Section 205 filing where ISO-NE and NEPOOL are in agreement, the Commission "plays 'an essentially passive and reactive' role"[5] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[6] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable – and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[7] The filed proposal "need not be the only reasonable methodology, or even the most accurate."[8] As a result, in a more typical Section 205 filing, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept the proposal reflected in the Section 205 filing if it is just and reasonable.[9] Here, however, if the Commission finds both proposals to be just and reasonable, the Commission has the latitude to choose between the NEPOOL and ISO-NE proposals based on what it views to be the preferable proposal, and is not bound to conclude that one proposal is unjust and unreasonable before it can consider the second proposal.[10] If there are any additional proposals filed by intervenors though, those proposals cannot be accepted unless the Commission first concludes that neither the NEPOOL Proposal nor the ISO-NE Proposal is just and reasonable and preferable.[11]

II. COMMUNICATIONS AND CORRESPONDENCE

Communications and correspondence regarding this proceeding should be sent to the individuals listed below:

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proposal or the alternate Market Rule proposal as it finds, in its discretion, to be just and reasonable and preferable.

[5] *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) (*quoting City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

[6] *Id.* at 9.

[7] *Cities of Bethany, et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

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

[9] *Cf. Southern California Edison Co., et al.*, 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 Cities of Bethany*, 727 F.2d at 1136)).

[10] *See* Participants Agreement at Section 11.1.5: "The Commission . . . may adopt any or all of ISO's Market Rule Proposal or the Alternate Market Rule Proposal as it finds, in its discretion, to be just and reasonable and preferable."

[11] *Cf. Southern California Edison Co., et al,* 73 FERC ¶ 61,219 at 61,608 n.73 (1995).

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III. NEPOOL PROCESS LEADING TO NEPOOL PROPOSAL

As required by the Participant Processes,[12] there has been a very deliberate and complete exploration and discussions among the ISO-NE, Market Participants and State regulators of market changes to improve the incentives and performance of resources, especially at times when they are most needed. Beginning with the issuance of ISO-NE's October 2012 white paper, entitled "FCM Performance Incentives" (referred to herein as the "FCM PI White Paper"),[13] ISO-NE led NEPOOL Participants and the States for over a year in discussions to explain its FCM "performances incentives" proposal and received feedback on that proposal. Prior to consideration by the Participants Committee, ISO-NE's proposal was reviewed and deliberated over the course of 15 Markets Committee meetings spanning a full year. Throughout the stakeholder process, NEPOOL Participants reacted and responded to ISO-NE's technical analysis and sought to explore alternative approaches.[14]

As the stakeholder process unfolded, Market Participants raised a host of concerns with the ISO-NE Proposal. Initial support for ISO-NE's conceptual proposal gradually eroded and almost completely disappeared as the commercial and market implications of an untested economic approach became understood and the ISO-NE Proposal's inflexibility in addressing broadly held concerns became apparent. In an effort to remedy their concerns with the ISO-NE Proposal during the final voting in the NEPOOL process, members offered numerous amendments and alternatives to the ISO-NE Proposal, all of which ISO-NE rejected.

One such effort was undertaken by NRG Energy, Inc. ("NRG") to develop a viable alternative to the ISO-NE Proposal that could: (1) achieve consensus, (2) reflect a preferred

[12] *See generally* Participants Agreement, *available at* http://nepool.com/uploads/Op-PA.pdf.

[13] *See* ISO-NE Strategic Planning Initiative white paper entitled "FCM Performance Incentives" (dated October 2012) at p. 3, *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/fcm_performance_white_paper.pdf. NEPOOL stakeholders had no input into the development of the FCM PI White Paper.

[14] Attachment N-1g provides a more detailed description of that involved process.

approach to address evolving regional challenges, and (3) better complement and enhance other market initiatives. Beginning as early as November 2012, NRG began to discuss an alternative approach to ISO-NE's FCM "performance incentives" proposal with the NEPOOL Markets Committee, ultimately developing and presenting proposed Tariff language reflecting the NRG alternative at the October 8-9, October 29 and November 13-14, 2013 Markets Committee meetings. While no proposal (neither the ISO-NE Proposal or an alternative) passed at the Markets Committee, Market Participants and State regulators continued to seek an alternative approach to the ISO-NE Proposal that addressed very broadly held regional concerns. Based on the feedback received from interested stakeholders, NRG revised its alternative proposal largely to remove and vote separately key features of its proposal but also to address some concerns that were motivating opposition to its alternative proposal.[15]

At the December 6, 2013 Participants Committee meeting, Market Participants coalesced around NRG's proposed alternative that was grounded in the current market design and enhanced the financial incentives to resources at times of high stress on the system by proposing targeted, incremental changes to the current markets (referred to herein as the "NEPOOL Proposal"). NEPOOL approved the NEPOOL Proposal by an 80.28% Vote of the Participants Committee,[16] while the ISO-NE Proposal received a Vote of only 10.28% in favor, with only 5.5[17] members supporting the ISO-NE Proposal. The voting results are tabulated in Attachment N-1h.

In considering the alternative proposals, the Commission should note that the NEPOOL vote in support of those changes, even over the objection of ISO-NE, exceeded 80%. This fact alone provides compelling evidence that the just and reasonable NEPOOL Proposal is preferable in the marketplace to the unsupported and untested ISO-NE Proposal. The votes of NEPOOL Participants on this matter were well considered and were informed by the extensive experiences and concerns of those who participate in New England's Forward Capacity Market, both suppliers and consumers.

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[15] NRG broke its larger, initial proposal into three separate amendments for NEPOOL consideration at the December 6, 2013 Participants Committee meeting.

[16] As explained in New England's response to Order No. 719, the Participants Committee is the Participant body that provides the final input by NEPOOL on changes to the Tariff, Manuals, Operating Procedures and other New England matters. New England's governance arrangements have been established to recognize that some Participants may be unable to participate fully and with the benefit of full management feedback until after the Technical Committees have completed their deliberations and made their recommendations. For that reason, all recommendations from the Technical Committee are considered by the Participants Committee (absent delegation to another representative of NEPOOL), but it is final Participants Committee action that defines NEPOOL's organizational position. (*see* Filing of ISO New England and New England Power Pool in Response to Order No. 719, Docket No. ER09-1051, filed Apr. 28, 2009.)

[17] The vote of the Generation Sector Group Seat was split evenly in support of and opposed to the ISO-NE Proposal, resulting in that vote being cast "0.5" in favor and the overall number of votes in favor not being a whole number.

IV. THE NEPOOL PROPOSAL IS JUST AND REASONABLE

Both ISO-NE and NEPOOL generally agree that new incentives should be provided in the New England electricity markets to improve the performance of resources when most needed and to attract new investment. This identified need is being largely driven by a concern that the current markets are not providing sufficient incentives to influence market behavior so that it will address New England's evolving strategic risks,[18] including challenges associated with the region's increased reliance on natural gas-fired generation.

As noted, ISO-NE has a very different vision of how to address its concerns compared to the changes supported by the Market Participants. ISO-NE proposes new incentives in the Forward Capacity Market by fundamentally modifying the current concept of what a capacity market is intended to achieve by making a resource's FCM compensation heavily dependent on resource output during short, unpredictable five-minute intervals of operating reserve scarcity, with little to no connection to the *adequacy* of the quantity of resources purchased in the Forward Capacity Auction.[19] Alternatively, the NEPOOL Proposal adds two incremental, but significant capacity and energy/reserve market changes to improve economic and performance incentives in the markets. Unlike ISO-NE's proposal, NEPOOL's proposed changes complement, and provide enhancements to, a number of other market changes that have either already been made, are pending implementation, or are planned to be explored in the near-term through the stakeholder processes.[20] The Tariff changes to implement the NEPOOL Proposal are contained in Sections I.2.2, III.2.7A and III.13.7 to Market Rule 1. As described further herein, NEPOOL supports addressing the real-time price formation and operational incentives identified by ISO-NE in its October 2012 FCM PI White Paper[21] in the Real-Time markets for Energy and Ancillary Services. Further, NEPOOL supports improving the FCM by making incremental changes, rather than fundamentally redefining the capacity product procured in the FCM.

A. Background: Relationship Between the Capacity Market and Shortage Pricing

Early in 2013, several New England generators asked Dr. David Patton, ISO-NE's External Market Monitor, to respond to a series of questions concerning ISO-NE's proposal.[22] In

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[18] *See* ISO-NE's Strategic Planning – Risk Summary, June 14, 2011, *available at* http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/4_spd_risk_summary_may_2011.pdf.

[19] Fuller Testimony at p. 2.

[20] Bowie Testimony at pp. 4-5.

[21] *See* FCM PI White Paper.

[22] Memo from Dominion, Entergy, NextEra, PSEG and TransCanada to David B. Patton, Ph.D., Potomac Economics (dated Dec. 21, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_nepool_mp_memo_12_21_12.doc.

his letter dated February 19, 2013, Dr. Patton provided his opinions on ISO-NE's proposal and the areas addressed by the questions.[23] One question asked Dr. Patton to opine on the differences between shortage pricing in Real-Time and ISO-NE's proposed "performance incentives" proposal. Dr. Patton explained that, if it is true that the markets do not provide adequate incentives for units to be available during shortages in Real-Time, then it would be because: (1) Real-Time prices during shortages are too low (i.e., RCPF values are too low)[24] and/or (2) ISO-NE takes reliability actions that eliminate efficient Real-Time pricing to reflect actual shortages.[25]

Citing Dr. Patton's response, ISO-NE explained thereafter that increasing the energy price in Real-Time could provide similar incentives to the incentives that may be provided for resources under its "performance incentives" proposal and concluded that "the incentives created by high prices during scarcity conditions are an effective means to motivate resource performance and availability."[26] ISO-NE went on to explain that one way to create these enhanced incentives in the New England markets is to set higher Reserve Constraint Penalty Factor ("RCPF") values during periods when there are shortages of operating reserves.[27]

In other words, in the opinions of Dr. Patton and ISO-NE, *higher RCPF values and the 'PI' approach would have similar effects on suppliers' incentives with respect to Real-Time performance and availability*.[28] Importantly though, while the higher RCPF values have a similar effect to ISO-NE's proposed approach, the risks associated with each approach differ greatly. While ISO-NE agrees with Dr. Patton's central observation that "the FCM Performance Incentives design is comparable, with respect to suppliers' incentives, to increasing Real-Time

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[23] David B. Patton, Ph.D., Potomac Economics (dated Feb. 19, 2013), *Questions on ISO New England Performance Incentives Proposal* ("Patton Letter"), *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_potomac_economics_memo_02_19_13.pdf.

[24] Patton Letter at p. 4. "The value (the RCPF) of 30-minute reserves is now $500/MWh. Hence, energy prices during modest shortages would be expected to range from $500 to $1000/MWh."

[25] *Id.* "If high-cost actions are taken outside the market to prevent a shortage, the prices will reflect neither the shortage nor the high-cost action." Dr. Patton stated that the "Real-Time price may not always fully reflect the value of energy due to the effects of the ISO's reliability actions or the fact that the value of reserves (i.e., the demand curve values that set price during shortages) is not set high enough to reflect the full expected value of foregone consumption."

[26] ISO-NE memorandum from Robert Ethier, Ph.D., Vice President, Market Development to NEPOOL Markets Committee (dated Mar. 15, 2013) at p. 1, *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_iso_memo_03_15_13.pdf.

[27] *Id.*

[28] *Id.* at p. 2. ISO-NE admits that "RCPF values serve several purposes, including facilitating automatic (Real-Time) redispatch of generation resources to avoid reserve shortages."

energy and reserve prices during reserve shortages" (or setting higher RCPF values),[29] through penalties and payments in the long-term capacity market the ISO-NE Proposal seeks instead to effectively mimic such incentives. In doing so, the ISO-NE Proposal strays from a more conventional shortage pricing structure and seeks fundamental changes to New England's capacity market, radically departing from the intended design of the FCM and all other North American electric market designs.

NEPOOL through its alternative proposal takes the more direct and broadly-supported approach of improving the incentives in the Real-Time, hourly markets by setting higher RCPF values during periods of reserve deficiencies. In addition, while retaining the fundamental structure for FCM, the NEPOOL Proposal improves the 'availability' metric in the FCM by replacing the current mechanism that only measures resource availability during random Shortage Events with an EFORp construct that would measure capacity resources' availability during high peak hours in the summer and winter months, corresponding to the hours when the system peak demand is most likely to approach, or even exceed, the forecasted peak load upon which the Installed Capacity Requirement is based.

B. Energy/Ancillary Market Changes

As indicated, to help address economic and operational inefficiencies in the Real-Time energy and reserve markets, the NEPOOL Proposal revises Tariff provisions to change the current RCPF system-wide value for Thirty-Minute Operating Reserves ("TMOR") and Ten-Minute Non-Spinning Reserves ("TMNSR") (the "RCPF Changes"). Specifically, the RCPF Changes will increase the current system-wide RCPF values for the TMOR product from $500/MWh to $1,000/MWh and for the TMNSR product from $850/MWh to $1,500/MWh.[30] These increases, reflected in Section III.2.7A of the Tariff, would ensure that all resources offered in the energy market are available to the dispatch software to: (1) maintain adequate reserves on the system; (2) allow resulting prices to provide a better indication of scarcity conditions; and (3) provide increased real-time incentives for availability and production in direct and immediate response to regional energy and reserve needs. These signals also provide a direct response to the concerns that ISO-NE identified in its October 2012 FCM PI White Paper and subsequent materials.[31]

The RCPFs serve as a price cap for the Real-Time price of each reserve product and there are separate RCPF values for each reserve product and for system-wide and local requirements.[32] As explained by ISO-NE's External Market Monitor:

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[29] *Id.*

[30] Fuller Testimony at pp. 6-7.

[31] Fuller Testimony at pp. 10-11; *see also* FCM PI White Paper.

[32] Fuller Testimony at p. 6. ISO-NE maintains reserve requirements for the following reserve products: Ten Minute Spinning Reserves ("TMSR"), Ten Minute Non-Spinning Reserves ("TMNSR"), and TMOR, and for each respective reserve product, there is a separate RCPF value. The TMSR RCPF is

> The RCPF levels are "important because they determine how the Real-Time market responds under tight operating conditions. If RCPFs are not sufficiently high, the model may not schedule all available resources to meet the reliability requirements and Real-Time clearing prices may not adequately reflect the market conditions when this occurs. In such cases, the operator will likely intervene to maintain reserves and significantly affect market clearing prices in the process. Hence, it is important to evaluate the RCPF levels periodically to determine whether modifications are warranted."[33]

The use of RCPFs to set efficient prices during operating reserve shortages has been endorsed by the Commission.[34]

The NEPOOL Proposal reflects the overwhelmingly preferred direction by Market Participants to enhance performance incentives in the New England markets by focusing on changes to address Real-Time price formation issues in the hourly markets (energy/reserve markets), rather than to "mimic" such Real-Time incentives with a fundamentally-modified capacity market product as proposed by ISO-NE. The new RCPF levels proposed by NEPOOL represent a positive step in this direction as they would establish more efficient price signals to the marketplace during reserve shortages, providing increased incentives for Real-Time availability and production in response to ISO-NE's energy and reserve needs during high stress conditions, driving better consumption, production and hedging decisions, and creating transparent and appropriate market and dispatch incentives to both load and supply.[35]

The higher RCPF levels will also: (1) ensure that all Demand Response resources (and all resources with offer prices above $500/MWh) would be fully available to ISO-NE for Real-Time dispatch in order to maintain operating reserve levels; (2) attract more reserve resources to the market, which will be especially important as intermittent resources are further integrated into the system; (3) better incent Market Participants to schedule in the Day-Ahead Energy Market and pursue other hedging activities with commercial counter-parties to limit and manage their

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$50/MWh, the TMNSR RCPF is $850/MWh, the system TMOR RCPF is $500/MWh, and the local TMOR RCPF is $250/MWh (*See* Section III.2.7A of current ISO-NE Tariff).

[33] 2011 Assessment of the ISO New England Electricity Markets, prepared by the External Market Monitor for ISO-NE (Potomac Economics), dated June 2012, at p. 68, *available at* http://www.potomaceconomics.com/uploads/isone_reports/ISONE_2011_EMMU_Report_Final_June_2012.pdf; *see also generally* Fuller Testimony.

[34] *Wholesale Competition in Regions with Organized Elec. Markets*, Order No. 719, 73 Fed. Reg. p. 64,100 (Oct., 2008), FERC Stats. & Regs. ¶ 31,281 (2008) (Order No. 719); *see also ISO New England Inc. and New England Power Pool*, Docket No. ER12-1314-000 (May 21, 2012) (unpublished letter order accepting revisions to increase the system-wide Reserve Constraint Penalty Factor for Thirty-Minute Operating Reserves).

[35] Fuller Testimony at pp. 7-8; Forshaw Testimony at pp. 7-8; Katz Testimony at pp. 6-7.

exposure to Real-Time prices; and (4) decrease the amount of total Net Commitment Period Compensation ("NCPC") incurred.[36]

C. FCM Changes

1. Overview of FCM

ISO-NE and New England stakeholders have been working over the last several years to improve the current FCM to better achieve the resource adequacy objectives intended for that Market. Under the FCM, ISO-NE conducts periodic auctions for the capacity it requires to satisfy the Net Installed Capacity Requirement or Net ICR. The ICR is set approximately three and a half years in advance of the applicable Capacity Commitment Period and defines the amount of capacity resources to be purchased in the Forward Capacity Auction ("FCA") for that Capacity Commitment Period. Recognizing that no resource is available 100% of the time, the calculation of ICR includes assumptions of availability based on actual historic performance of all existing resources. Existing Capacity Resources are deemed to be in the auction as a price taker unless they submit a price-based de-list bid or seek to retire from the market altogether. New Capacity Resources offer in the FCA to provide capacity based upon long-run average costs and are subject to Offer Review Trigger Prices. Resources that clear in the FCA receive Capacity Supply Obligations ("CSOs").[37]

One of the fundamental issues in this proceeding is the nature of the obligations that would be held by resources as a consequence of taking on a CSO. Under the current arrangements, CSOs are to be paid the price at which capacity cleared in the applicable Forward Capacity Auction (or reconfiguration auction or the bilateral transaction prices), with that amount subject to two potential reductions. The first is a deduction for Peak Energy Rents, which are not at issue here. The second deduction, which *is* at issue in this proceeding, is a deduction that occurs if a resource is not available (as "available" is defined in the Tariff) during a Shortage Event.[38] In this proceeding, both NEPOOL and ISO-NE propose to replace the Shortage Event mechanism for measuring the 'performance' or availability of capacity resources with a newly proposed metric. As described further in their respective filings and supporting materials, the two entities propose markedly different approaches for this performance mechanism. An overview of NEPOOL's proposed capacity resource availability metric is described below with further detail provided in supporting testimony and reflected in NEPOOL-approved Tariff language.

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[36] Fuller Testimony at pp. 8-10.

[37] *See generally* Section III.13 to Market Rule 1 (the "Forward Capacity Market Rules").

[38] The definition of "Shortage Event" was recently expanded to include more circumstances than previously defined. *See ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,095 (Nov. 1, 2013).

2. Description and Rationale for FCM Changes

The NEPOOL Proposal replaces the Shortage Event mechanism with a new performance mechanism, based on an "EFORp" metric. Instead of measuring performance only during Shortage Events (i.e, random reserve deficiency events when RCPFs are triggered), NEPOOL's proposed mechanism would measure performance based on availability during all "EFORp Hours."[39] EFORp Hours would be defined as four afternoon hours on summer weekdays and two evening hours on winter weekdays,[40] corresponding to hours when system load is expected to be highest, suggesting that the adequacy of overall supply would be most critical.[41]

The Commission has already approved evaluation metrics that measure resource availability during pre-defined peak hours, including in California, PJM Interconnection, Inc. ("PJM"), and New York.[42] As an example, a group of stakeholders in California advocated for the adoption of an EFORp performance metric because it would "provide … incentive to maximize availability during peak hours."[43] The Commission later accepted a reiteration of this proposal, finding that performance standards that evaluate a supplier's capacity payments based on past performance during certain hours was just and reasonable.[44] In PJM, the Commission has found that region's EFORp performance metric to be a just and reasonable way to evaluate performance in a capacity market.[45] Accordingly, the Commission has not only approved the concept of measuring the performance of capacity resources based on defined peak-hour periods, as NEPOOL is currently proposing, but specific programs in other RTOs across the country.

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[39] *See* Section III.13.7.1.1.3; Fuller Testimony at pp. 11-13.

[40] "EFORp Hours" are defined as "the hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January." *See* Fuller Testimony at p. 13. This definition matches the current tariff definition of "Demand Resource On-Peak Hours" in Section I of the ISO-NE Tariff.

[41] Fuller Testimony at pp. 13, 18-19. NEPOOL recognizes that there also are other times in Real-Time operations when energy and reserve production are critical to reliability. Its proposed changes address these concerns directly as well through improved Real-Time prices.

[42] *See, e.g., California Independent System Operator Corporation ("CAISO")*, 127 FERC ¶ 61,298 (2009) (June 2009 Order); *PJM Interconnection, LLC ("PJM")*, 126 FERC ¶ 61,275 (2009) (March 2009 Order); *New York Independent System Operator, Inc. ("NYISO")*, 145 FERC ¶ 61,192 (2013) (December 2013 Order).

[43] *Proposal for forward capacity market in California*, submitted by FPL Energy Project Management, NRG Energy, Inc., Reliant Energy, Inc., San Diego Gas & Electric Company, Southern California Edison Company (Aug. 3, 2007, at p. 8, *available at* http://www.caiso.com/1c32/1c32ba981c0e0.pdf.

[44] June 2009 Order at P 25.

[45] *PES v. PJM*, 128 FERC ¶ 61,051 (2009) (July 2009 Order).

As an incentive to make capacity resources available during these critical peak-hour periods, NEPOOL's proposed EFORp construct at the end of each Capacity Commitment Period would impose charges or provide credits to resources based on their availability in all EFORp Hours during that Capacity Commitment Period. Using the current definition of availability as set forth in Section III.13.7.1.1.3, NEPOOL's proposed EFORp construct would calculate an availability score for each capacity resource for each EFORp Hour.[46] ISO-NE would then accumulate and average the hourly scores to calculate an annual "EFORp Hour Availability Score" for each capacity resource.[47] The EFORp Hour Availability Score during any Capacity Commitment Period would be compared to the resource's average EFORp Hour Availability Score during the historical 5-year period used to establish ICR.[48] Based on that Score, the resource would be paid or charged deviations at 150% of the FCA Clearing Price, subject to annual caps.[49] ISO-NE would aggregate all credits to be paid to resources with better-than-historic Availability Scores, and all charges to be collected from resources with worse-than-historic Availability Scores. The net of charges and credits would be refunded or charged to load based on the Capacity Load Obligation of each Load Serving Entity. Beyond the changes described herein, all other currently effective FCM provisions would remain in place (including the Peak Energy Rent provisions).[50] The mechanics of NEPOOL's proposed EFORp construct are more fully detailed in the redlined Tariff language as well as in the Fuller Testimony, which are included as attachments to this transmittal letter.[51]

Since the EFORp Hours correspond to hours when system load is expected to be highest, and thus the adequacy of overall supply would be most critical, the proposed mechanism provides a meaningful incremental incentive for all capacity resources to be highly available during such hours.[52] It also calibrates the overall cost of capacity experienced by load to the amount of availability delivered by capacity resources.[53] If the overall availability of capacity resources during EFORp Hours is higher than during the historical period used in establishing the ICR, while the amount of purchased capacity remains unchanged, capacity resources would be effectively delivering higher reliability than reflected in the ICR, which load would pay for

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[46] Fuller Testimony at p. 14.

[47] *Id*.

[48] *Id*. As described further in this filing letter, the total amount of MW of resources required to be procured in the FCA, to satisfy the system's adequacy requirements of the Net ICR, is based on the forecasted load for the future Capacity Commitment Period and the historic availability of the existing fleet of resources.

[49] *See* NEPOOL-proposed Section III.13.7.2.7.1.2 (Attachments N-2b and N-2c); *see also* Fuller Testimony at p. 14-15.

[50] Fuller Testimony at p. 18.

[51] *See* NEPOOL-approved Tariff sheets (Attachments N-2b and N-2c); Fuller Testimony at pp. 11-18.

[52] Fuller Testimony at p. 18.

[53] *Id*.

with a small surcharge (i.e., reflecting a higher overall capacity price). Likewise, if there is a lower overall availability, again the total purchased capacity would be unchanged but load would not have received all the reliability it paid for and would receive a credit to reflect the lowered availability (i.e., effectively a lower overall capacity price).[54]

In summary, NEPOOL's proposed EFORp metric is designed to complement the RCPF changes discussed above, to measure the availability of resources that have committed to provide resource adequacy in a pre-defined set of hours each year when resource adequacy is most at risk. With the capability to assess whether resources with CSOs are available at expected levels during critical peak periods, the proposed mechanism ultimately enhances the incentive for all resources with CSOs, whether scheduled in the Day-Ahead Market or not, to be available to ISO-NE for commitment and dispatch (consistent with their physical characteristics and capabilities) when they are most likely to be needed and provides load with greater assurance that their payments for capacity will help maintain peak-hour period reliability.[55]

V. THE NEPOOL PROPOSAL IS PREFERABLE TO THE ISO-NE PROPOSAL

While NEPOOL Participants generally agree with ISO-NE that the existing market pricing signals need to be stronger and that more economic incentives need to be provided to improve the performance of resources when they are most needed, virtually all of NEPOOL views the ISO-NE Proposal, as considered by the Participants Committee, as the wrong approach to try to achieve that objective.[56] The NEPOOL Proposal reflects a preferred approach that better addresses the concerns that are motivating changes to the New England markets through incremental change to the reserve and capacity markets rather than a major and unnecessary redefinition of the FCM product.[57]

A. Dr. Richard Tabors, NEPOOL's Consultant, Has Identified Fundamental Flaws With The Construct of the ISO-NE Proposal

At NEPOOL's request, Richard D. Tabors has reviewed the ISO-NE Proposal and provided his assessment in a report (the "Tabors Report"), which is included as part of Attachment N-1f to this transmittal letter. Dr. Tabors explains through a number of examples why he concludes that the ISO-NE Proposal has fundamental flaws, is inconsistent with market design principles that characterize an efficient and competitive market, and results in unjust and unreasonable outcomes.[58]

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[54] *Id*. at p. 17.

[55] *Id*. at pp. 18-19.

[56] *See* Forshaw Testimony at pp. 4-7.

[57] *Id.* at pp. 4-6.

[58] *See generally* Tabors Report.

The Tabors Report identifies the following flaws with ISO-NE's proposal: [59]

- First, the ISO-NE Proposal assumes that a CSO's forward financial position is only a share of the system's energy and reserve requirements during a "Capacity Scarcity Condition". Dr. Tabors walks through a series of examples that produce results demonstrating that this assumption is arbitrary, unjustified and inconsistent with sound capacity market design.[60]

- Second, the outcome of the ISO-NE Proposal would yield incremental financial rewards to generators for doing nothing more than what they were committed to do given their CSOs, as well substantial penalties to generators in some cases for performing precisely as reflected in their operating parameters, leading to a "massive redistribution of revenues among generators."[61]

- Third, the ISO-NE Proposal causes redistribution of revenues in a way that has little relation to cost causation. As Dr. Tabors observes, when a "Capacity Scarcity Condition" is experienced, a generator would receive or be penalized approximately an equivalent amount whether the scarcity is 1 kW, 1 MW or 100 MW.[62]

In the opinion of Dr. Tabors, and as supported by specific illustrative examples in the Tabors Report, the ISO-NE Proposal would not achieve ISO-NE's stated objectives, would result in compensation to generators in excess of what an efficient market would provide, would make and extract "performance payments" for reasons that are inconsistent with the realities of actual system operations and decision-making, and would favor certain resources over other types of resources.[63] In his view, implementation of the ISO-NE Proposal as constructed would result in payments and penalties that would not be just or reasonable.

B. The NEPOOL Proposal Focuses Change Where It Is Needed In The Hourly Markets, While Keeping FCM Consistent With Its Original Intent As A Resource Adequacy Market

The energy and ancillary reserve markets, not the capacity market, is the better place to make Market Rule changes to ensure the energy and operating reserve production by resources when needed.[64] The ISO-NE Proposal, however, seeks a fundamental and unnecessary

[59] *Id*.

[60] *Id.* at pp. 7-8.

[61] *Id*.

[62] *Id*. at p. 8.

[63] *See generally* Tabors Report.

[64] *See generally* Bowie Testimony; Forshaw Testimony at pp. 4, 7-8; Tabors Report at p. 2.

redefinition of the capacity product such that it would transform FCM into an operational performance market for capacity resources rather than the resource adequacy capacity market it was intended to be.[65] As described in this Section V, the NEPOOL Proposal instead seeks to build upon and emphasize changes already underway in the energy and reserve markets and to avoid a major and unnecessary redesign of the capacity product.

1. FCM As A Resource Adequacy Market

Dating back to the contemplation of accepting ISO-NE's proposed locational installed capacity ("LICAP') mechanism, and litigation stemming from that proposal, the Commission expressed a need to find a mechanism to "provide adequate assurances that necessary electric generation capacity or reliability would be provided."[66] Following oral argument, and without an alternative to LICAP, the Commission noted its concern about resource adequacy in New England – and the need for a capacity market to address this concern effectively.[67] As the Commission stated: "[a] capacity market mechanism should both provide adequate revenues to appropriately compensate (and keep in service where needed for reliability) existing capacity resources and provide incentive for the development of new infrastructure in areas where it is most needed."[68]

In furtherance of those goals, the Commission approved as just and reasonable, a Settlement Agreement that established the FCM. The new FCM focused on resource adequacy by establishing capacity auctions where "[t]he amount of capacity procured will be that amount required to maintain the installed capacity requirement".[69] As accepted by the Commission as just and reasonable, Market Rule 1 requires ISO-NE to:

> determine the Installed Capacity Requirement[70] such that the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance *with this resource adequacy planning criterion* shall be evaluated probabilistically, such that the Loss of Load Expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year.[71]

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[65] *Id*.; Katz Testimony at pp. 2-4.

[66] *Devon Power LLC*, 115 FERC ¶ 61,340 (2006) ("June 16 Order").

[67] *Devon Power LLC*, 113 FERC ¶ 61,075 (2005) ("October 2005 Order").

[68] *Devon Power LLC*, 107 FERC ¶ 61,240 (2004) ("June 2 Order").

[69] June 16 Order at P 17.

[70] "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.

[71] *See* ISO-NE Market Rule 1, Calculation of Capacity Requirements, § III.12.1 (emphasis added).

Further, the ISO-NE Tariff defines a "Capacity Supply Obligation" as 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."[72]

In the end, the final Settlement Agreement approved by the Commission was a culmination of different design elements with one goal: to design an FCM that "integrates elements of these [alternative] market designs and is intended to help assure resource adequacy and reliability for New England at just and reasonable rates."[73]

2. Capacity Markets in Other RTOs

Consistent with the FCM in New England, the definition of capacity as a resource adequacy product has also been accepted by the Commission as just and reasonable in other RTO/ISO centralized capacity markets.[74] PJM uses such a definition of capacity for its market.[75] Consistent with this resource adequacy approach to capacity, Section 1.3, or Definition and Purpose of Reliability Pricing Model, unequivocally declares that "[t]he Reliability Pricing Model is the PJM resource adequacy construct that ensures that adequate Capacity Resources … will be made available to provide reliable service to loads within the PJM Region."[76] Further, Section 2.1 of the PJM Capacity Market Manual, entitled Overview of Resource Adequacy, states that the "purpose of PJM RPM resource adequacy is to determine the amount of capacity resources that can be required to serve the forecast load that satisfies the PJM reliability criterion."[77] Similarly, the New York Independent System Operator ("NYISO") also uses a resource adequacy construct in its capacity market.[78] NYISO's capacity market has a standard for resource adequacy that requires system planners to calculate an installed capacity requirement in MW for the Capability Year.[79] The Commission has also approved as just and

[72] *See* Section I.2.2 (Definitions) of ISO-NE Tariff.

[73] *Explanatory Statement in Support of Settlement Agreement of Settling Parties*, Docket Nos. ER03-563-000, -030, and -055 (Mar. 6, 2006).

[74] *See* ISO-NE Market Rule 1, Standard Market Design, § III.13.1.1; PJM, Manual 18 PJM Capacity Market, § 1.2.2; NYISO, Manual 4: Installed Capacity Manual, § 4.2.2.

[75] *PJM Interconnection*, LLC, 137 FERC ¶ 61,108 (2011).

[76] PJM, Manual 18 PJM Capacity Market, § 1.2.

[77] *Id*. at § 2.1.

[78] NYISO, Manual 4: Installed Capacity Manual, §§ 2.3, 2.4. Like New England, NYISO's resource adequacy standard (or "NPCC Resource Adequacy Standard") requires "the probability of disconnecting firm Load due to a Resource deficiency (Loss of Load Expectancy, or "LOLE") to be, on the average, no more than once in ten years after due allowance for: Scheduled and forced outages and scheduled and forced deratings; Assistance over interconnections with neighboring Control Areas and regions; and Capacity and/or Load relief from available operating procedures."

[79] *Id.*

reasonable a proposal by the California Independent System Operator Corporation ("CAISO"), declaring that CAISO's proposed capacity construct comported with the standard capacity product, or resource adequacy.[80]

The Commission recently reinforced the resource adequacy nature of the capacity product in RTOs across the nation.[81] In a report issued in preparation for the September 25, 2013 Commission Technical Conference on Centralized Capacity Markets in RTOs/ISOs (the "September Technical Conference"), Commission Staff explained that the capacity product currently consists of: "[r]esources available to generate energy or reduce load when needed"[82] and that the function of a capacity product is to "meet the planning reserve margin at just and reasonable rates."[83] The Commission has expressed that the current product in New England, NYISO, and PJM does so.[84] Put another way, the capacity product is a basic product, "*intended simply to meet the planning reserve margin*."[85]

During the Commission's September Technical Conference, panelists described the current capacity product as: "a single capacity product focused on meeting basic resource adequacy requirements, with any operational attributes needed to meet system requirements procured in the energy and ancillary services markets."[86] Consistent with this view, the Commission has made it clear that short-term operating reserve concerns do *not* currently fit within the generally accepted capacity definition. Put succinctly: "[w]hile the centralized capacity markets include a locational component to account for transmission constraints and ensure that capacity is available and deliverable to load, *other operational considerations are generally not considered when defining what types of capacity the market will procure*."[87] In fact, one of the topics of the September Technical Conference was to evaluate whether capacity products should be modified to reflect various operational characteristics.[88] Thus, there is no question that current capacity product definitions and markets, already approved as just and reasonable, focus primarily on resource adequacy – not Real-Time production of energy or operating reserves.

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[80] *See, e.g., CAISO*, 127 FERC ¶ 61,298 (2009); *CAISO*, 141 FERC ¶ 61,135 (2012).

[81] *Centralized Capacity Market Design Elements, Commission Staff Report*, in FERC Docket No. AD13-7-000 (Aug. 23, 2013) ("Commission Staff Report"). The Commission Staff Report noted that "all three eastern RTO/ISO centralized capacity markets define the capacity product in a generic way, generally allowing resources available to generate energy or reduce load when needed to compete solely on price to become a capacity resource." Commission Staff Report at p. 15.

[82] Commission Staff Report at p. 15.

[83] *Id.*

[84] *Id.*

[85] *Id.* at p. 18.

[86] *Notice Allowing Post-Technical Conference Comments*, Docket No. AD13-7-000 (2013).

[87] Commission Staff Report at p. 16 (emphasis added).

[88] *Id.*; *Notice Allowing Post-Technical Conference Comments*, Docket No. AD13-7-000 (2013).

3. ISO-NE's Proposal to Fundamentally Redefine the Capacity Product in New England is Inconsistent with Long-Standing Commission Precedent and Unnecessary

While NEPOOL's proposal based on the current resource adequacy capacity product is consistent with long-standing Commission precedent, the ISO-NE Proposal reflects a fundamental departure from such precedent. Notwithstanding the underlying basis for FCM and ICR, ISO-NE now proposes to make capacity payments heavily dependent on whether a resource actually produces energy or operating reserves in Real-Time during "Capacity Scarcity Conditions". Those scarcity conditions cannot be reasonably anticipated in advance. Nor can the performance of all but a handful of generators, as discussed below. As a result, the ISO-NE Proposal will effectively eliminate any ability of many resources reasonably to rely on capacity revenues to support investment.[89]

With implementation of reforms to the Energy and Ancillary Services markets —those made in the recent past, those approved and to be implemented, and those included in the NEPOOL Proposal — a redesigned capacity product as dramatic as ISO-NE is proposing is unnecessary and unjustified.[90] Those Energy and Ancillary Services market reforms include: modifications to the bidding/offer deadlines in the Day-Ahead Energy Market;[91] changes to permit bidders increased energy offer flexibility, including the opportunity to make hourly intra-day re-offers and to offer energy at negative prices;[92] modifications to permit the use of a Reserve Constraint Penalty Factor of $250/MWh for the replacement reserve requirement in place of normal supplemental commitment;[93] changes to authorize ISO-NE's procurement of additional ten-minute non-spinning reserves in the Forward Reserve Market;[94] changes to generating resource auditing requirements and procedures;[95] changes to the Forward Reserve Market incentives;[96] market mitigation modifications to allow dual-fuel units to take better

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[89] *See generally* Fuller Testimony.

[90] Bowie Testimony at pp. 4-5; Forshaw Testimony at pp. 4-6.

[91] *ISO New England Inc. and New England Power Pool*, 143 FERC ¶ 61,065 (Apr. 24, 2013).

[92] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,014 (Oct. 3, 2013).

[93] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1736-000 (Aug. 15, 2013) (unpublished letter order accepting revisions to establish a Reserve Constraint Penalty Factor for the Replacement Reserve Requirement).

[94] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-465-000 (Feb. 8, 2013) (unpublished letter order accepting revisions to Forward Reserve Market Rules to permit the procurement of additional Ten-Minute Non-Spinning Reserve).

[95] *ISO New England Inc. and New England Power Pool*, 142 FERC ¶ 61,024 (Jan. 9, 2013).

[96] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1733-000 (Aug. 15, 2013) (unpublished letter order accepting revisions concerning Forward Reserve Market incentives).

advantage of fuel switching capability;[97] and expanded authority for ISO-NE to communicate with natural gas pipeline operators.[98] And to the extent confusion over obligations under existing Tariff provisions was adversely affecting performance, that too has recently been addressed.[99] All of these changes combined with the additional changes in the NEPOOL Proposal, should be implemented and given a chance to address resource performance issues before the current capacity product is abandoned in favor of a new unproven concept that moves away from the resource adequacy construct.[100]

In fact, ISO-NE clearly acknowledges that the changes specified above are important market and operational improvements that will help to address strategic risks. ISO-NE recently informed stakeholders that it has decided not to move forward with a specific supplemental reliability program for Winter 2014-15 (or subsequent winter periods) precisely because of these significant operating and market enhancements, including changes to the Day-Ahead Energy Market schedule, the use of replacement reserves, increases in ten-minute reserve requirements, and improved auditing rules and additional changes that are pending implementation (i.e., the energy market offer flexibility and associated Net Commitment Period Compensation ("NCPC") payment changes).[101] As stated by ISO-NE at the November 2013 Markets Committee meeting, "ISO and Market Participants have limited experience with these changes and have not yet gone through an entire winter with the Winter 2013-14 changes in place."[102]

In sum, the NEPOOL Proposal takes a far more measured approach to ensuring performance of capacity resources when they are most needed.[103] The NEPOOL Proposal will allow analysis and careful adjustment of those improvements already underway in the energy and reserve markets while avoiding major disruption of an existing market. The NEPOOL Proposal treats installed capacity as it was intended, capacity available to meet the resource

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[97] *ISO New England Inc. and New England Power Pool*, Docket No. ER14-707-000 (Jan. 15, 2014) (unpublished letter order accepting relocation of dual-fuel switching provisions).

[98] *See* Pipeline Information-Sharing Changes, *ISO New England Inc. and New England Power Pool Participants Committee*, Docket No. ER14-970-000 (filed Jan. 10, 2014).

[99] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 144 FERC ¶ 61,157 (2013), *order on reh'g*, 145 FERC ¶ 61,206 (Dec. 6, 2013). Commission-issued clarifications in response to the NEPGA Complaint concerning the 'performance' obligations of resources with Capacity Supply Obligations.

[100] Bowie Testimony at pp. 4-6; Forshaw Testimony at pp. 7-8.

[101] *See* ISO-NE presentation to NEPOOL Markets Committee at its Nov. 13-14, 2013 meeting, "Winter 2014-15 Solutions Update", *available at* http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a11_iso_presentation_11_13_13.ppt.

[102] *Id*. at p. 2.

[103] Katz Testimony at p. 2, 5-8; Forshaw Testimony at p. 7; Tabors Report at pp. 2, 11-12.

adequacy criterion of loss of load no more than one day in ten years.[104] Real-Time performance and energy delivery issues are appropriately addressed through the Real-Time Energy and Ancillary Services markets, and the NEPOOL Proposal seeks to improve the financial incentives through more efficient price signals in those hourly markets.[105]

C. The NEPOOL Proposal Better Balances Risks with Rewards

ISO-NE's untested and unproven theoretical proposal will impose significantly increased risks on capacity suppliers and large additional expenses on electricity consumers in New England.[106] With increased risks of large penalties, especially on the many resources that are neither fast-start nor baseload capable units, the ISO-NE Proposal may also exacerbate reliability issues by hastening the retirement of units that would otherwise be available to ensure resource adequacy.[107] In the alternative NEPOOL Proposal, NEPOOL seeks incremental changes that complement and enhance other recently made or pending market initiatives, rather than fundamentally redefining the capacity product. In doing so, the NEPOOL Proposal better balances risks with rewards by respecting commercial realities over economic theory.

1. Increased Penalties and Higher Costs Under the ISO-NE Proposal

The ISO-NE Proposal would inappropriately impose penalties on capacity resources for failure to produce energy or operating reserves during a "Capacity Scarcity Condition" when the reason for non-performance is beyond the control of those resources.[108] As an example, under the ISO-NE Proposal, transmission outages that prevent a capacity resource from producing energy or operating reserves during a "Capacity Scarcity Condition" would result in FCM penalties.[109] Similarly, capacity resources could be exposed to penalties for non-delivery even when a resource is following ISO-NE dispatch instructions or an ISO-approved planned

[104] Fuller Testimony at p. 4 ("This [NEPOOL's] mechanism for measuring the availability of generating resources recognizes that the FCM is the market that was established to help ensure resource adequacy to meet the planning reliability criterion (i.e., the Installed Capacity Requirement or ICR). The ICR is based on projections of average resource availability, and not, as is inherent in the ISO-NE Proposal, the real-time production of energy or reserves.").

[105] *Id*. ("Increasing the value of these penalty factors will allow prices in the real-time energy and ancillary service markets to better reflect reserve scarcity when it occurs, leading to more efficient valuation of the products needed to balance supply and demand in real-time while protecting against contingency events. This in turn will lead to better incentives for real-time availability and performance of resources, and better information with which load-serving entities and end-use consumers of electricity can manage their consumption and commercial hedging activities."); Katz Testimony at pp. 6-8; Tabors Report at pp. 11-12.

[106] Katz Testimony at pp. 3-5, 6-8; Forshaw Testimony at pp. 6-7; Tabors Report at pp. 2, 10.

[107] Fuller Testimony at pp. 19-20; Forshaw Testimony at pp. 6-7.

[108] Bowie Testimony at pp. 6-7; Katz Testimony at pp. 3-5; Tabors Report at p. 9.

[109] Bowie Testimony at pp. 6-7; Tabors Report at p. 9.

maintenance outage.[110] These kinds of non-delivery are not avoidable through additional investment in equipment, and thus the penalties serve no purpose but to raise revenues to compensate other resources, whether they hold CSOs or not.[111]

The following are a few additional examples where a resource could be penalized in circumstances that are virtually impossible to predict or prepare for and/or for reasons beyond a resource's control:

- It is a hot summer day and a solar generating capacity resource has been providing energy to the system and performing as expected. Then just after sunset, a "Capacity Scarcity Condition" is triggered by, for example, a large baseload unit experiencing a forced outage or transformer malfunction, and that same solar resource that had performed well all day long is off-line after sunset. Despite providing useful support to the system during a very hot summer day, this solar generating unit would be penalized under the ISO-NE Proposal for a reason completely beyond its control. An analogous example would be a wind capacity resource that fails to generate during a "Capacity Scarcity Condition" because the winds just happen to not be blowing during the time that ISO-NE would be measuring its new definition of performance.

- Having received an ISO-approved planned maintenance schedule, a nuclear generating facility is off-line due to maintenance activities on a typical October afternoon. Suddenly, and without notice, a "Capacity Scarcity Condition" occurs due to a contingency somewhere on the system. Under the ISO-NE Proposal, capacity resources would be measured based on their delivery of energy or reserves during scarcity conditions. Even though that nuclear unit would have performed at 100% if it had been on-line, since it was undergoing an ISO-NE pre-approved maintenance outage at the time of the "Capacity Scarcity Condition", the resource is hit with large performance charges, notwithstanding that ISO-NE has approved it being off-line and had made other arrangements to ensure sufficient resources would be available to ensure Real-Time reliability.

- ISO-NE under-projects Day-Ahead energy needs resulting in Real-Time loads materially exceeding forecast. Under the ISO-NE Proposal, despite an inaccurate load forecast, certain capacity resources, whose operating parameters require a longer lead time to begin operations, without having

[110] Bowie Testimony at pp. 6-7, 9; Tabors Report at p. 9.

[111] *See generally* Tabors Report.

received a Day-Ahead commitment would still be subject to significant performance charges with all associated risk placed squarely on them.[112]

- ISO-NE dispatches a generator through the Operating Day and instructs it to shutdown as load begins declining. After that instructed shutdown has occurred, an operating resource experiences an unexpected outage, resulting in a "Capacity Scarcity Condition." The generator that followed ISO-NE's dispatch instructions will be penalized for not producing energy or operating reserves.[113]

The capacity resources subject to such unavoidable and virtually unhedgeable risks[114] will have no choice but to build a risk premium into their capacity offers, thereby raising the costs for all with only the hope of theoretical future benefits for the system. Additionally, penalizing capacity resources for not operating while on a planned maintenance outage for example will tend to create a perverse incentive for those resources to forestall or minimize planned maintenance, thereby putting into jeopardy system reliability.[115]

As indicated, because of the significant risk of increased, unpredictable and virtually unhedgeable penalties (and with no exemptions) new capacity suppliers subject to these increased risks under the ISO-NE Proposal are likely to build substantial risk premiums into their capacity offers[116], and existing capacity suppliers can be expected to de-list their resources to avoid receiving a CSO unless they receive a much higher capacity price.[117] These reactions will raise the cost of capacity for all 32,000MW plus of New England capacity resources. These expenses may prove to be entirely unnecessary because the performance issues that ISO-NE seeks to address are effectively addressed through reforms to the energy and ancillary services markets specified above.[118] More importantly, those reforms to the energy and ancillary service

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[112] One of the factors that caused a recent OP4 and Shortage Event on December 14, 2013 was an under-forecasting of load by over 600 MW. *See* "NEPOOL Participants Committee Report January 2014", Vamsi Chadalavada, Executive Vice President and Chief Operating Officer (Jan. 10, 2014), available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/jan102014/coo_report_jan_2014.pdf.) ISO-NE acknowledged that generator performance during that period was positive. Under the ISO-NE Proposal, thousands of MW of generating resources would have been subject to penalties during that event.

[113] Tabors Report at pp. 6-7.

[114] *Id*. at p. 9.

[115] Bowie Testimony at p. 6.

[116] Katz Testimony at pp. 3-4; Forshaw Testimony at pp. 6-7.

[117] *See generally* Fuller Testimony at pp. 19-20.

[118] Bowie Testimony at pp. 3-6. In addition to the market initiatives specified herein, at the January 14-15, 2014 NEPOOL Markets Committee meeting, ISO-NE and stakeholders commenced a

markets will better connect increased costs for load to the load that creates the greater demand. The ISO-NE Proposal does not result in that close tie between costs and beneficiaries.[119]

The NEPOOL Proposal does not contain the unreasonable penalties that would be imposed under the ISO-NE Proposal, thereby substantially reducing the risk premium that would be included in capacity offers to cover unpredictable risks.[120] Instead, the NEPOOL approach would make scarcity price signals more visible to both buyers and sellers, improving consumption incentives as well as production incentives, and creating a better environment for commercial contracting and hedging activities.[121] In addition, the NEPOOL Proposal maintains the character of the FCM product as a resource adequacy product, distinct from the Real-Time delivery of energy and/or operating reserves and in doing so each resource's FCM revenues are far less risky than under the ISO-NE Proposal, which will make it far less costly to maintain efficient existing capacity and to invest in new capacity in the region, and better sustain that investment over time.[122]

Further, there are no penalties for non-delivery due to transmission outages under the NEPOOL Proposal, which is appropriate because those outages are beyond the capacity resource's control.[123] There are no penalties for non-delivery due to ISO-approved planned maintenance, which is entirely appropriate given that the purpose of such maintenance is to help maintain reliability and is pre-approved by ISO-NE taking into consideration the reliability needs of the system in approving such unit outages.[124] Also, the NEPOOL Proposal does not penalize resources for following ISO-NE dispatch instructions, which again avoids sending the wrong signal to capacity resources that could be counterproductive to maintaining reliability.[125]

2. Unfair Treatment of Capacity Resources Under the ISO-NE Proposal

The ISO-NE Proposal does not treat all capacity resources comparably because it seeks to redefine capacity effectively as a product that can only be provided economically by baseload energy resources or fast-start peaking resources that can operate within 10 to 30 minutes of being called upon. Under ISO-NE's Proposal, when a "Capacity Scarcity Condition" is triggered, only resources that are producing energy and/or providing reserves at the time of and during the "Capacity Scarcity Condition" (as measured by ISO-NE in each five-minute interval) will be

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stakeholder process to explore the design and possible implementation of a sloped demand curve for the region's capacity market.

[119] Forshaw Testimony at pp. 6-7.

[120] Forshaw Testimony at pp. 6-7; Katz Testimony at pp. 6-8; Tabors Report at pp. 2, 11-12.

[121] Fuller Testimony at pp. 19; Katz Testimony at pp. 6-8.

[122] Fuller Testimony at pp. 19-20.

[123] Tabors Report at p. 9.

[124] *Id*.

[125] *Id*.

able to avoid significant penalties. In reality, the pool of capacity resources in New England includes thousands of MWs of valuable resources that are neither economically dispatched every single day, nor capable of providing fast starts. Many of these resources provide substantial reliability benefits to the region, but under the ISO-NE Proposal they could be perfectly maintained and respond perfectly to all ISO-NE dispatch instructions, yet still be subject to significant financial penalties because of ISO-NE's redefinition of the capacity product. While there is a need for baseload and fast-start resources, there is no economic rationale to procure that characteristic from every resource in an amount equal to the ICR.

Thus, if implemented, the ISO-NE Proposal is likely to hasten the retirement of units that would otherwise be available to ensure resource adequacy, which could exacerbate reliability problems, rather than solve them.[126] With respect to existing capacity resources, the elimination of the FCM floor price has already triggered a far higher level of active participation (i.e., the submittal of de-list bids and Non-Price Retirement Requests for FCA8) by existing resources, based on their economic outlook under the existing FCM construct.[127] The ISO-NE Proposal significantly ratchets up the risk of participation in the markets by existing capacity resources (and especially for legacy fossil units), increasing the likelihood of both priced de-list bids and Non-Price Retirement Requests as a risk-mitigation strategy.[128] With over 8,000MW "at risk" according to ISO-NE's 2012 retirement study, rather than solving reliability problems, the risky and untested ISO-NE Proposal will increase the reliability risk of retirements or the need for additional reliability-must run contracts which will increase existing problems with the FCM.[129] Reflecting a more measured and commercially-rational approach to addressing evolving regional challenges, the NEPOOL Proposal on the other hand avoids creating this problem.

VI. REQUESTED EFFECTIVE DATES

NEPOOL seeks the same effective dates for the NEPOOL Proposal as are sought by ISO-NE for its Proposal. Any changes to the Real-Time markets (i.e., the RCPF Changes), and changes needed to be understood at the time resources begin to submit qualification packages for the ninth Forward Capacity Auction ("FCA9"), are requested to become effective June 1, 2014. Changes that affect payments for resources that clear in FCA9 are requested to become effective on June 1, 2018. For all changes, NEPOOL joins ISO-NE in seeking a final Commission order on or before May 14, 2014.

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[126] Forshaw Testimony at p. 6-7.

[127] Fuller Testimony at p. 20; Forshaw Testimony at p. 6.

[128] Fuller Testimony at p. 20.

[129] *Id.*; *see also* ISO-NE's Strategic Transmission Analysis: Generation Retirements Study (dated Dec. 13, 2012), *available at* http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2012/dec132012/retirements_redacted.pdf.

Because 18 C.F.R. § 35.3(a)(1) requires tariff changes to become effective no more than 120 days after being filed with the Commission, NEPOOL requests waiver of that requirement and asks the Commission to accept both the June 1, 2014 and June 1, 2018 effective dates.

VII. 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.[130] However, the NEPOOL Proposal does not change a traditional "rate", and neither NEPOOL nor ISO-NE are a traditional investor-owned utility. In light of these circumstances, NEPOOL submits the following additional information in substantial compliance with relevant provisions of Section 35.13, and requests a waiver of Section 35.13 of the Commission's regulations to the extent the content or form deviates from the specific technical requirements of the regulations.

35.13(b)(1) – Materials included herewith are identified more specifically on pages 2-3 of this transmittal letter and the joint transmittal letter accompanying part 1 of this filing.

35.13(b)(2) – As set forth in Section VI above, NEPOOL requests that the changes to Section III.2 (i.e., the RCPF value changes) become effective June 1, 2014; the changes to Sections I.2.2. (Definitions) and III.13 (FCM changes), June 1, 2018.

35.13(b)(3) – Pursuant to Section 16.11(a)(iv) of the Second Restated NEPOOL Agreement and Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in Attachment I-1k. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in Attachment I-1k 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, IV and V of this transmittal letter.

35.13(b)(6) – As discussed in Section III of this transmittal letter and in more detail in Attachment N-1g, the changes to the Tariff reflect the results of the Participant Processes required by the Participants Agreement. The NEPOOL Proposal was approved by a NEPOOL Vote of 80.28%.

[130] 18 C.F.R. § 35.13 (2014).

35.13(b)(7) – NEPOOL has 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) – ISO-NE 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 NEPOOL Proposal's Tariff revisions filed herein.

VIII. CONCLUSION

For the reasons stated in this transmittal letter and in the attached testimony supporting this filing, the Commission should approve the NEPOOL Proposal, which is just and reasonable and preferable to the ISO-NE Proposal.

Respectfully submitted,

NEPOOL PARTICIPANTS COMMITTEE

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Dated: January 17, 2014

ATTACHMENT N-1b

Testimony of Peter D. Fuller,
Director of Regulatory Affairs,
NRG Energy Inc., East Region,
on behalf of NEPOOL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___000**
NEPOOL Participants Committee	**)**	

TESTIMONY OF PETER D. FULLER

Q. Please state your name, position and business address.

A. My name is Peter D. Fuller. I am Director of Regulatory & Market Affairs for NRG Energy, Inc.'s East Region ("NRG"). My business address is 104 Carnegie Center, Princeton, New Jersey, 08540.

Q. Please describe your professional experience and qualifications.

A. I hold a Bachelor of Science degree in Electrical Engineering from Bucknell University and a Master of Science in Electrical Engineering from Northeastern University. Since January 2008, I have held the position of Director, Regulatory & Market Affairs for NRG Energy Inc. In this position, I am responsible for NRG's state, regional and federal regulatory and policy activities in New England, including the company's interactions with the ISO New England wholesale markets as well as supporting the company's asset optimization and business development efforts in the region. Prior to joining NRG, I was Director of Market Affairs for Mirant Energy Trading from 2000-2007. I was a Vice-Chair of the New England Power Pool Participants Committee representing the Generation Sector from 2004 to 2013, and served as Chairman of the Participants Committee for 2006 to 2007. I currently serve as the Chair of the NEPOOL Budget & Finance Subcommittee. From 2005 to 2010, I served as Chairman of the New England Power Generators Association, the largest trade association representing independent power producers in New England. Prior to joining Mirant in 2000, I held a number of positions in power supply, planning and engineering with Eastern Utilities Associates. I have previously testified before the Massachusetts

Department of Public Utilities and the Connecticut Public Utilities Regulatory Authority.

Q. Can you please briefly describe the two alternate sets of Market Rule changes proposed by ISO-NE and NEPOOL, respectively, in this proceeding?

A. ISO New England Inc. ("ISO-NE") proposes to fundamentally modify the current FCM structure, and the basic concept of what a capacity market is intended to achieve, by making a resource's FCM compensation heavily dependent on resource output during short, unpredictable intervals of operating reserve scarcity, with little to no connection to the *adequacy* of the quantity of resources purchased in the Forward Capacity Auction (the "ISO-NE Proposal"). The ISO-NE Proposal would replace the existing "Shortage Event" penalty structure with a new 'performance incentive' mechanism, resulting in capacity payments to resources that would be the combination of two components: (1) a base capacity payment and (2) a performance payment or charge. The performance payment or charge would be entirely dependent upon the resource's delivery of energy or operating reserves during 'scarcity conditions,' and could be larger than the base payment.

NEPOOL seeks an alternative approach to the ISO-NE Proposal. At its December 6, 2013 Participants Committee meeting, NEPOOL approved an alternative set of revisions to the Market Rules that would maintain the FCM capacity product as a tool to ensure *resource adequacy*, and would place real-time performance incentive-related improvements directly into the energy and reserve markets. NEPOOL's proposed changes are intended to complement and enhance a number of other changes already made or currently pending in the energy and operating reserve markets. Specifically, NEPOOL proposes to (i) increase the values of the Reserve Constraint Penalty Factors ("RCPF") for Thirty-Minute Operating Reserves ("TMOR") and Ten-Minute Non-Spinning Reserves ("TMNSR") for the entire New England Control Area; and (ii) replace the current

"Shortage Event" mechanism for measuring the 'performance' of resources with Capacity Supply Obligations in the Forward Capacity Market with an 'EFORp' availability metric (collectively, the "NEPOOL Proposal").

Q. What is the purpose of your testimony?

A. My testimony describes the market design changes proposed under the NEPOOL Proposal and explains the reasons for proposing such changes. I also explain why the NEPOOL Proposal is better than the ISO-NE Proposal.

Q. In summary, why did NRG offer the NEPOOL Proposal?

A. Throughout stakeholder discussions over the past year, NEPOOL members and state representatives almost uniformly expressed concerns with the ISO-NE Proposal. Those concerns had been reflected in numerous presentations made by me and others to ISO-NE in the stakeholder process. I have included in *Attachment N1-b.1* to my testimony links to a number of my presentations on behalf of NRG that were circulated to and discussed with the NEPOOL Markets Committee during the past year that summarize NRG's concerns and the basic elements that comprise the NEPOOL Proposal. There were overwhelming concerns expressed by regional stakeholders, including many discussions concerning identified issues, blind spots and shortcomings of the ISO-NE Proposal, but ISO-NE nonetheless has proceeded with its proposal to address its concerns with the market. NRG's objective in the process was always on addressing ISO-NE's identified concerns with the market through a viable alternative to the ISO-NE Proposal that also was responsive to the overwhelming concerns with the ISO-NE Proposal and other, long-standing concerns NRG and others have with the markets. In the end, we were successful in achieving broad consensus through a preferred approach to address evolving regional challenges that actually considers, complements and enhances other market initiatives that have already been made or are pending.

Q. Please summarize the main elements of the NEPOOL Proposal.

A. The NEPOOL Proposal consists of two main elements. The first element would increase the RCPFs for the system-wide TMOR and TMNSR products. Increasing the value of these penalty factors will allow prices in the real-time energy and ancillary service markets to better reflect reserve scarcity when it occurs, leading to more efficient valuation of the products needed to balance supply and demand in real-time while protecting against contingency events. This in turn will lead to better incentives for real-time availability and performance of resources, and better information with which load-serving entities and end-use consumers of electricity can manage their consumption and commercial hedging activities.

The second element of the NEPOOL Proposal would institute a performance metric for generating capacity resources based on roughly 256 pre-defined summer hours and roughly 86 pre-defined winter hours, corresponding to hours when the demand on the system is most likely to be at or near the forecasted seasonal peaks for the year. This mechanism for measuring the availability of generating resources recognizes that the FCM is the market that was established to help ensure *resource adequacy* to meet the planning reliability criterion (i.e., the Installed Capacity Requirement or ICR). The ICR is based on *projections* of average resource availability, and not, as is inherent in the ISO-NE Proposal, the real-time production of energy or reserves. By using this refined performance metric, the NEPOOL Proposal will have a much lower risk profile associated with capacity market payments to generating resources than the ISO-NE Proposal. A lower risk profile will lead to a more stable investment climate, thereby advancing another recognized goal of the FCM which has been to provide a reliable and predictable revenue stream to encourage market investment in New England capacity when and where needed. To the extent this mechanism contributes to revenue stability, it will tend to lower the cost of investing, and should lead to lower overall capacity costs to consumers relative to the capacity costs that

would result from the ISO-NE Proposal, which places greater risk on resource owners.

Q. Provide an overview of ISO-NE's dispatch process in the Real-Time Energy and Reserve Markets.

A. As has already been explained in a joint ISO-NE/NEPOOL filing submitted in March 2012 in Docket No. ER12-1314-000, ISO-NE dispatches resources in the real-time energy market to provide energy and reserves to meet real-time demand for electricity and to maintain required quantities of the various reserve types system-wide and in pre-defined reserve zones. It accomplishes this task through a co-optimized market-clearing system that is part of the Unit Dispatch System ("UDS"). The system operators typically approve a new dispatch solution every 5 to 10 minutes (the "dispatch interval"). This co-optimization process produces dispatch quantities and real-time prices based on the submitted offer data and real-time operational constraints, including system and local reserve requirements and transmission constraints. When there is sufficient reserve supply and no re-dispatch for reserves, real-time reserve prices are zero. When resources are in merit to provide energy, but instead are re-dispatched or kept offline to provide reserves, positive real-time reserve prices will occur.

Q. What are Reserve Constraint Penalty Factors?

A. Reserve Constraint Penalty Factors ("RCPFs") serve as a cap for the real-time price of each reserve product. As the physical availability of reserves to meet the reserve requirement decreases, the cost of re-dispatching resources to maintain the reserve requirement increases. The co-optimized dispatch software will re-dispatch resources to maintain the required levels of reserves as long as the marginal cost of doing so is less than or equal to the applicable RCPF. Once the RCPF is reached, the co-optimizing software will not take further actions. At that point, ISO-NE system operators must intervene manually in the dispatch if there

are insufficient reserves available below the RCPF price, and these manual actions will necessarily result in uplift and price distortion.

Q. Please explain the relationships among the existing reserve products' RCPF values.

A. ISO-NE maintains reserve requirements for the following reserve products: local and system-wide TMOR, TMNSR, and system-wide Ten Minute Spinning Reserves ("TMSR"). For each respective reserve product, there is a separate RCPF value. As reflected in Section III.2.7A of the ISO-NE Tariff, the TMSR RCPF is $50/MWh, the local TMOR RCPF is $250/MWh, the system TMOR RCPF is $500/MWh, and the system TMNSR RCPF is $850/MWh.

Q. Please describe the relationship between real-time reserve prices and real-time energy prices.

A. The purpose of the co-optimization of energy and reserves in real-time is to reflect the fact that, at the margin, there is a trade-off in seeking to meet both the energy demands of the system and the requirements to hold some resources in reserve at all times. When the UDS software re-dispatches the system to maintain reserve levels, the incremental value of energy and reserves is equivalent, and this relationship is expressed by including the non-zero real-time price of reserves in the Locational Marginal Price ("LMP") for energy.

Q. Describe the proposed RCPF value changes.

A. The revision to the market rules in the NEPOOL Proposal would increase the system TMOR RCPF value from $500/MWh to $1000/MWh and the system TMNSR RCPF value from $850/MWh to $1500/MWh. The primary purpose of increasing the TMOR RCPF value is to enable the co-optimization software to access all available resources in attempting to meet the system-wide TMOR requirement (i.e., up to the allowable cap on energy offers of $1,000/MWh). Under the NEPOOL Proposal, the TMNSR RCPF value would be increased

above this cap, recognizing, as is already recognized in the currently established RPCFs, that there is a higher incremental value for TMNSR when the system is running short of that form of reserves.

Q. What pricing inefficiencies occur when the system TMOR and system TMNSR prices reach their respective RCPF values?

A. Once the RCPFs are hit, reserve prices are capped and the resulting price signals for the TMOR and TMNSR products, and thus for energy, fail to convey the true marginal cost of those products during the dispatch intervals when they are most valuable. As explained above, the UDS software normally co-optimizes the dispatch of resources on a least-cost basis to satisfy the energy and reserve needs of the system, producing real-time energy and reserve prices. When the system TMOR price reaches $500/MWh or when the system TMNSR price reaches $850/MWh, then further dispatch of reserves must be undertaken via manual actions of ISO-NE operators. These actions, by virtue of the fact that they come from resources with offer prices above the respective RCPFs, or because they are reserved for use only in high-stress conditions, are explicitly or implicitly more expensive than the RCPFs, and yet do not become visible in market prices because they are dispatched manually. When the existing RCPFs are capped below the allowable offer costs of dispatchable resources in the hourly markets, the real-time reserve prices do not always reflect the true cost of providing the TMOR or TMNSR products. Thus, when the RCPFs are triggered and reserve prices are capped, the costs associated with ISO-NE's manual actions to restore and maintain operating reserves are not transparent to the marketplace at precisely those times when reserves are most needed.

Q. What benefits are likely to result with such increases to the RCPF values for the system TMOR and system TMNSR requirements?

A. Increasing the system TMOR RCPF value to $1000/MWh and the system TMNSR RCPF value to $1500/MWh is a clear improvement to the status quo,

allowing the co-optimization software to access all resources offered into the real-time markets to meet the energy and reserve requirements of the system, and ensuring that the prices in those circumstances of greatest need rise to reflect that need. In so doing, the revised RCPFs will provide more efficient price signals to the marketplace during reserve shortages than are currently provided. These more efficient market signals will increase real-time incentives for availability and production in response to ISO-NE's energy and reserve needs during high stress conditions, which is a key concern ISO-NE identified in its initial white paper proposing its market reforms. Higher real-time prices will drive better consumption, production and hedging decisions, with the result being more transparent and appropriate market and dispatch incentives to both load and supply than currently provided when caps and uplift interfere with such signals. The higher RCPF levels will also: (1) ensure that all Demand Response resources (and all resources with offer prices above $500/MWh) would be fully available to ISO-NE for real-time dispatch in order to maintain operating reserve levels; (2) attract more reserve resources to the market, which will be especially important as intermittent resources are further integrated into the system; (3) better incent Market Participants to schedule in the Day-Ahead Energy Market and pursue other hedging activities with commercial counter-parties to limit and manage their exposure to real-time prices; and (4) decrease the amount of total Net Commitment Period Compensation ("NCPC") incurred.

Q. Please expand on each of these four points.

A. The first benefit is that the co-optimizing software will no longer be limited in its ability to use all of the resources offered in the real-time energy market to manage the system's energy and reserve needs, and to set prices based on the actual marginal cost of meeting those needs. ISO-NE filed, and the Commission recently approved, market rule changes that will fully integrate demand response resources into the energy markets, including requiring demand response resources with capacity obligations to offer their resources into the energy markets each day (*See* Docket No. ER12-1627). In that filing, at the behest of its Internal Market

Monitor, ISO-NE proposed and the Commission approved that demand response resources would not be subject to offer price mitigation in the energy markets, on the basis that all of a demand response resource's opportunity costs should be included in an economic offer, and that such opportunity costs could be very high and difficult for the IMM to estimate. As such, it is expected that some demand response resources will offer into the energy market at high prices, perhaps approaching the offer cap of $1000/MWh. Coupled with ISO-NE's stated intentions to ensure that such demand response resources can participate in the operating reserve markets to the extent they are capable, it is critically important that these resources be available to the co-optimization software. Even today, there are resources that offer into the energy market at prices greater than $500/MWh, and greater than $850/MWh, and the existing RCPFs exclude these resources from consideration in the co-optimization algorithm.

The second benefit is that more robust real-time prices for reserves will encourage additional resources to make their reserve capability available to the market, and may encourage new entry of resources specifically intended to participate in the real-time and Forward Reserve Markets. The Forward Reserve Market will also be strengthened as a result of the incrementally higher real-time reserve prices, since the forward market tends to reflect expectations of real-time reserve pricing. Both from an operational and an investment perspective, the increased RCPFs will encourage additional participation in the reserve markets. In addition to increasing competition in these markets and driving long-run efficiencies, this increased participation will be increasingly important as the region experiences growth in its supply of intermittent sources of renewable energy. This has been identified as one of ISO-NE's five major strategic challenges (*See* ISO-NE's Strategic Planning – Risk Summary, June 14, 2011, *available at*: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/4_spd_risk_summary_may_2011.pdf.).

A third benefit I referenced earlier is improved incentives for both load-servers and suppliers of energy and reserves to engage in efficient levels of hedging using available commercial vehicles, such as the Day-Ahead Energy Market as well as longer-term bilateral contracts to manage their exposure to real-time price volatility. The potential for real-time energy and reserve prices to be significantly higher than average prices increases the incentive for both sellers and buyers to seek out mechanisms to smooth out their anticipated revenue or cost, respectively.

Finally, the fourth benefit which I identified is that Net Commitment Period Compensation ("NCPC"), which reimburses generation resources for offered costs and fees that are not covered by market revenues based on clearing prices, should be reduced. To the extent real-time energy and reserve prices better reflect the actual marginal cost of meeting the system's energy and reserve needs, fewer resources should experience the revenue shortfalls that NCPC is designed to cover.

Q. Can you further explain why the new RCPF values will improve real-time price signals in the New England hourly markets and address the real-time market incentive problems identified by ISO-NE in its October 2012 White Paper?

A. Yes. In the opinion of my company as well as many others, the existing energy market prices do not fully capture the cost or value of maintaining energy and reserves at all times, and this under-pricing of scarcity affects long-term investment prospects as well as real-time operational incentives. ISO-NE acknowledges this problem/issue in its October 2012 white paper (*See* ISO-NE White Paper: FCM Performance Incentives, dated October 2012, *available at*: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/fcm_performance_white_paper.pdf.).

The NEPOOL Proposal will improve those price signals for the dispatch intervals in which the system would otherwise experience a TMOR or TMNSR deficiency and capped reserve prices under today's RCPF values. The new RCPF values for the TMOR product of $1000/MWh and for the TMNSR product of $1500/MWh will allow ISO-NE to more efficiently re-dispatch resources through the UDS system thereby enhancing the co-optimization of the energy and reserve markets. As a result, real-time energy and reserve prices will better reflect the incremental cost of the marginal resource that provides TMOR and TMNSR. This should significantly improve the accuracy of reserve price signals seen in the marketplace at times when reserves are most valuable, when TMOR or TMNSR reserves are scarce and their marginal cost exceeds $500/MWh and $850/MWh, respectively.

Q. Does the NEPOOL Proposal include any Market Rule changes to New England's Forward Capacity Market?

A. Yes. The other major element of the NEPOOL Proposal would be an incremental change to New England's Forward Capacity Market ("FCM") rules so that, going forward, it would measure "performance" of generating capacity resources based on their availability for ISO-NE commitment and dispatch in a pre-defined set of high load hours. This is in contrast to the current FCM, which measures "performance" only in "Shortage Events," which occur based on certain shortages of operating reserves that persist for at least thirty contiguous minutes. If there are no Shortage Events in a given year, each resource's capacity revenues for that year would be entirely divorced from its actual availability. Conversely, if there are Shortage Events, they can happen almost at random and a resource's capacity revenues can be materially impacted without any regard for how that resource actually performed during high load periods.

The NEPOOL Proposal also is distinct from the ISO-NE Proposal, which would measure "performance" during "scarcity conditions." Like Shortage Events, "scarcity conditions" would be based on shortages of operating reserves.

"Scarcity conditions," however, would be defined by the ISO-NE Proposal to occur in any *five-minute* dispatch interval, rather than being required to persist for at least thirty minutes to constitute a Shortage Event to be declared. In addition, the ISO-NE Proposal would measure "performance" of a resource as the MWh of energy or reserves actually provided during that five-minute interval, rather than measuring whether the resource had made itself available for ISO-NE in the day-ahead and real-time markets in accordance with the resource's physical characteristics. The NEPOOL Proposal for the FCM, in contrast, is designed to complement the RCPF changes discussed above, and to measure the availability of resources that have committed to provide resource adequacy in a pre-defined set of hours each year when resource adequacy is most at risk.

Q. What is the current definition of a system-wide Shortage Event?

A. Since the beginning of the FCM in June of 2010, ISO-NE has defined system-wide Shortage Events to occur when there is a shortage of ten-minute operating reserves for thirty or more contiguous minutes and the RCPF for the ten-minute requirement is binding. As of November 3, 2013, a system-wide Shortage Event can also be triggered in any Capacity Zone when the thirty-minute operating reserve requirement is binding or has been violated for thirty or more contiguous minutes.

Q. How is the performance of generating capacity resources currently measured during Shortage Events?

A. ISO-NE calculates an availability score for each resource with a Capacity Supply Obligation ("CSO") for each Shortage Event. Per the current FCM rules, a resource is deemed to be "available" if it is available for ISO-NE to commit and dispatch consistent with the resource's stated characteristics, and the resource has not experienced a forced outage (other than due to transmission limitations outside the control of the resource). Any resource that is unavailable during a Shortage Event will be penalized up to five percent of its annual FCM revenues,

or more if the Shortage Event persists for more than five hours (*See generally* Section III.13.7 of the current Tariff).

Q. Does the NEPOOL Proposal seek to replace the "Shortage Event" mechanism?

A. Yes. The NEPOOL Proposal would replace the current Shortage Event mechanism in the FCM with a new availability metric that would assess the availability of capacity resources across pre-defined peak hours during a given capacity commitment year (or Capacity Commitment Period) (referred to as an "EFORp" mechanism). Instead of measuring availability only during random reserve deficiency events when RCPFs are triggered (i.e., Shortage Events or scarcity conditions), NEPOOL's proposed mechanism would measure availability, using the same availability standards that exist in Section III.13.7.1.1.3 of the Tariff today, during high demand periods defined as "EFORp Hours."

Q. How are "EFORp Hours" defined?

A. EFORp Hours would be four afternoon hours on summer weekdays and two evening hours on winter weekdays. As specified in revised Section III.13.7.1.1.1 of the NEPOOL Proposal, "EFORp Hours" are defined as the hours ending 1400 through 1700, Monday through Friday on non-holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-holidays during the months of December and January. These are the same hours currently defined in the ISO-NE Tariff as "Demand Resource On-Peak Hours," and represent hours when the system is historically most at risk for high levels of demand approaching or exceeding the forecasted annual or seasonal peak.

Q. What is the "EFORp Hour Availability Score" and how is it calculated?

A. Using the current definition of "availability" as set forth in Section III.13.7.1.1.3 of the Tariff, and under NEPOOL's proposed EFORp construct, ISO-NE would calculate an availability score for each capacity resource for each EFORp Hour, which would represent the proportion of the resource's CSO megawatts that were available during the hour. ISO-NE would then accumulate and average the hourly scores to calculate an annual EFORp Hour Availability Score for each capacity resource.

Q. How are Availability Credits or Charges calculated under the EFORp construct?

A. The EFORp Hour Availability Score for a given Capacity Commitment Period would be compared to the capacity resource's average EFORp Hour Availability Score measured during the historical five-year period used to establish the Installed Capacity Requirement (or ICR). Deviations between the annual Score and the historical average would be paid or charged at 150% of the applicable zonal FCA Clearing Price, subject to annual caps (*See* NEPOOL-proposed Section III.13.7.2.7.1.2).

As an illustrative example, consider a 100MW resource that had an average EFORp Hour Availability Score of 90% in the five-year historical period used to establish existing unit availabilities in calculating the ICR. Further assume that, for a given Capacity Commitment Period, the resource takes on a CSO for its full 100MW of Qualified Capacity at the FCA Clearing Price of $5.00/kW-month. The resource's anticipated annual FCM revenues, prior to any adjustments, would be (100,000kW x $5.00/kW-month x 12 months = $6 million). Now assume that the resource's actual EFORp Hour Availability Score for this Capacity Commitment Period is 85%. The resource would be charged for the 5% deviation in the Score, in the amount of (85%-90%) x 100,000kW x $5.00/kW-month x 12 months x 150% = -$450,000, or 7.5% of the resource's annualized base FCM

revenue. Likewise, if the resource's actual EFORp Hour Availability Score for the year was 95%, it would receive an extra $450,000 in revenues.

Q. Is NEPOOL proposing any caps or other limitations on resources' revenues under this mechanism?

A. Yes, NEPOOL is proposing two such limitations. The first is an adaptation of the annual cap that exists in today's FCM, in which a capacity resource cannot lose more than its annualized FCM revenues. In order for that cap to bind, a capacity resource would have to have an actual EFORp Hour Availability Score for a given year less than 33.3% of its historical five-year average EFORp Hour Availability Score. For example, the 100MW resource in the example above, with a historical availability score of 90%, would need to have a Score of less than 30% in order for this cap to limit its lost revenues. This provides a wide bandwidth in which the marginal incentive for availability in the EFORp Hours would remain in place, encouraging resource owners that had poor availability in the early part of a summer to continue efforts to improve availability through the rest of the year.

The second is a limitation on the lost revenue that a resource could incur in the event of a Force Majeure event experienced by the resource, limiting such loss to no more than 20% of the annualized FCM revenues, subject to timely and accurate notification to ISO-NE of the existence of the Force Majeure and a diligent effort by the resource owner to bring the resource back into service following that Force Majeure event (*See* NEPOOL-proposed Section III.13.7.2.7.1.3(b)). The Force Majeure protection would also be prospective only, meaning that if the Force Majeure event occurred in the middle of a Capacity Commitment Period in which the resource owner had already incurred poor availability during EFORp Hours, the 20% limitation would not result in the resource owner 'clawing back' revenues already lost, and likewise, the 20% limitation would be pro-rated for the portion of the Capacity Commitment Period

remaining after the declaration of Force Majeure (*See* NEPOOL-proposed Section III.13.7.2.7.1.3).

Q. Please explain the rationale for the proposed limitation in the event of Force Majeure.

A. The proposed Force Majeure provision is based on several practical considerations reflecting the long-term nature of capacity market investments. Capacity resources are generally considered to have lifetimes in excess of twenty years or more. In order for competitive electricity markets to work, such resources need to be able to recover their long-run costs, on average and over time. In the event of a Force Majeure that results in a capacity resource being unavailable for an extended period, that resource would already be losing all of its energy and ancillary market revenues during the outage, impacting its near-term cash flow as well as its long-term economics. Without the proposed Force Majeure provision, the resources also would likely lose for an extended outage all of its capacity revenues as well, at exactly the time when it may be faced with significant incremental capital expenditures. The limitation on losing all of the capacity revenues under these circumstances is another way in which the NEPOOL Proposal is designed to limit risk while providing meaningful marginal incentives for availability. By putting reasonable bounds on the risk facing investors, the NEPOOL Proposal should encourage investment and keep costs as low as possible.

Q. Please describe the proposed changes to the "Poorly Performing Resources" provision of the Tariff.

A. The existing Tariff contains a provision, Section III.13.7.1.1.5, that can lead to a resource being declared ineligible to participate in the FCM if both of the following are true: in the most recent four consecutive Capacity Commitment Periods or the most recent four years in which the resource assumed a Capacity Supply Obligation: (a) the resource received three annual availability scores of

less than or equal to 40%; and (b) the resource has failed to be available in its entirety during ten or more Shortage Events during that same period. The NEPOOL Proposal would eliminate the second factor of this test, since Shortage Events would no longer exist, and would make the first factor more stringent by looking at two of the last three years/Capacity Commitment Periods rather than three of the last four. This change is intended to accelerate the process by which poorly performing resources are excluded from the capacity market, while still recognizing the long-term nature of capacity commitments and the yearly three-year look-ahead nature of the FCM design.

Q. How are credits and charges settled/allocated under the proposed availability metric?

A. Under the NEPOOL Proposal, ISO-NE would aggregate all annual credits to be paid to capacity resources with better-than-historic Availability Scores, and all charges to be collected from resources with worse-than-historic Availability Scores. Credits collected from 'under-performers' would be paid to 'over-performers.' Any residual would be credited or charged to Load-Serving Entities ("LSEs") based on each load entity's Capacity Load Obligation. This is a just and reasonable approach since the charges and credits are derived from the difference between actual resource availabilities and their availabilities during the historical time period used to determine the amount of capacity needed to satisfy the resource adequacy planning requirement, i.e., the ICR. To the extent that the aggregate availability of the capacity resources is better than in the assumed historical period, the region is getting marginally better performance and availability compared to the ICR and should pay effectively a higher price for higher reliability; and to the extent the aggregate availability is worse than historical, the region is getting less than what it bargained for in setting the ICR, and should be refunded some of the cost of capacity, so it effectively pays a lower price for the lower reliability.

Q. Does the NEPOOL Proposal contain any other changes to the current FCM rules?

A. No. Beyond the changes described herein, all other currently effective FCM provisions would remain in place (including the Peak Energy Rent provisions). As such, under the NEPOOL Proposal, the FCM would continue to be conducted on the basis of ICAP and Demand Resources and Intermittent Power Resources, which are not currently measured on the basis of Shortage Events, would continue to be measured in the same ways as they are under the current tariff.

Q. How does the proposed EFORp construct improve the current FCM design?

A. As already explained, the EFORp Hours correspond to hours when system load is expected to be highest, and thus the adequacy of overall supply would most likely be at risk. Accordingly, the proposed mechanism provides a meaningful incremental incentive for all capacity resources to be highly available during the peak load hours when system adequacy is most at risk, and also calibrates the overall cost of capacity experienced by load to the amount of availability delivered by capacity resources. If the overall availability of capacity resources during EFORp Hours is higher than during the historical period used in establishing the ICR, capacity resources are effectively delivering more than the minimum ICR, and this 'over-performance' is appropriately reflected in a marginally higher cost of capacity to the region. Likewise, lower overall availability, resulting in a credit to load, is consistent with a system that is delivering incrementally less reliability than was specified in the ICR. In sum, the proposed EFORp metric enhances the incentive for all resources with CSOs, whether scheduled in the day-ahead market or not, to be available to ISO-NE for commitment and dispatch (consistent with their physical characteristics and capabilities) during defined high-load hours in the summer and winter months, not just during unpredictable Shortage Events or scarcity conditions. With the capability to assess whether resources with CSOs are available at expected levels during critical peak periods, the proposed mechanism ultimately provides CSO

owners an added incentive to ensure their capacity resources are available when they are most likely to be needed and provides LSEs with greater assurance that their payments for capacity will help maintain peak-hour period reliability.

Q. Why is the NEPOOL Proposal better from your perspective than the ISO-NE Proposal?

A. At the most fundamental level, the NEPOOL Proposal is superior to the ISO-NE Proposal because the NEPOOL Proposal seeks to solve concerns with real-time performance by addressing the identified, and widely acknowledged, real-time market price formation problems in those markets directly. In contrast, the ISO-NE Proposal does nothing to address the underlying problem with real-time price formation and instead seeks effectively to substitute new real-time production based charges and payments in the capacity market for efficient real-time market price outcomes. The NEPOOL approach would make scarcity price signals more visible to both buyers and sellers, improving consumption incentives as well as production incentives, and creating a better environment for commercial contracting and hedging activities. Under the ISO-NE Proposal, real-time scarcity price signals to load would be dampened or non-existent, which may drive inefficient consumption and would provide an inappropriately large and comprehensive hedge that many load-servers and consumers would not choose if acting in their own commercial interests. The NEPOOL Proposal is based, in part, on a fundamental belief in commercial markets and that individual Market Participants can make better decisions in their own commercial best interests than a centralized regulatory mechanism.

In addition, the NEPOOL Proposal maintains the character of the FCM product as a *resource adequacy* product, distinct from the real-time delivery of energy and/or operating reserves. In doing so, each resource's FCM revenues are far less risky than under the ISO-NE Proposal. A more stable and reliable capacity revenue stream will facilitate new investment in capacity in the region, and better sustain that investment over time.

With respect to the existing fleet, the elimination of the FCM floor price has already triggered a far higher level of active efforts by existing resources to not take on CSOs (i.e., the submittal of de-list bids and Non-Price Retirement Requests in FCA8), based on their economic outlook under the existing FCM construct. The ISO-NE Proposal significantly ratchets up the risk of participation in the capacity market, especially by legacy fossil units, increasing the likelihood of both priced de-list bids and Non-Price Retirement Requests as a risk-mitigation strategy if the ISO-NE Proposal is implemented. With over 8,000MW already "at risk" under the existing FCM, according to ISO-NE's 2012 retirement study, the ISO-NE Proposal could increase the reliability risk of retirements or the need for additional reliability-must run contracts which will increase existing problems with the FCM.

The NEPOOL Proposal represents a moderate and rational path to a sustainable and efficient set of wholesale markets that is more amenable to efficient real-time incentives and performance outcomes, and that will better support an efficient level of investment in long-term capacity resources, and is far preferable to the risky and untested ISO-NE Proposal.

Q. Does this conclude your testimony?

A. Yes.

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

Peter D. Fuller

Executed on: 17 January, 2014

NRG Materials Provided to NEPOOL Markets Committee Materials Related to the ISO-NE and NEPOOL Proposals

Date	Document Title / Description	Internet Location
Nov 06, 2013	NRG Presentation 10-08-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14h_nrg_presentation_10_08_13.ppt
Nov 06, 2013	NRG MR 1 Redlined 10-03-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14h_nrg_mr_1_redlined_10_03_13_r1.doc
Oct 25, 2013	NRG MR 1 Redlined 10-03-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b7_nrg_mr_1_redlined_10_03_13_r1.doc
Oct 23, 2013	NRG Presentation 10-08-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b7_nrg_presentation_10_08_13.ppt
Oct 04, 2013	NRG Presentation 10-08-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c1_nrg_presentation_10_08_13.ppt
Oct 04, 2013	NRG MR 1 Redlined 10-03-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c1_nrg_mr_1_redlined_10_03_13.doc
Sep 18, 2013	NRG Presentation 09-20-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a1_nrg_presentation_09_20_13.ppt
Aug 06, 2013	NRG Presentation 08-07-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10d_nrg_presentation_08_07_13.ppt
May 08, 2013	NRG Presentation 05-14-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/may14152013/a04b_nrg_presentation_05_14_13.ppt

Date	Document Title / Description	Internet Location
Mar 06, 2013	NRG Presentation 03-12-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_nrg_presentation_03_12_13.ppt
Jan 24, 2013	NRG Presentation 01-29-13 *FCM - And Broader - Market Reforms - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b2_nrg_presentation_01_29_13.ppt
Jan 23, 2013	NRG Alternative Proposal 11-16-12 *FCM Performance Incentives - An Alternative Proposal - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b2_nrg_alternative_proposal_11_16_12.pdf
Jan 23, 2013	Group of Generators Presentation 01-29-13 *FCM Performance Incentives: Initial Areas of Focus - By Capital Power, Dominion, EquiPower, Entergy, Exelon, NextEra and NRG*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b3_generator_group_presentation_01_29_13.ppt
Nov 16, 2012	NRG Alternative Proposal 11-16-12 *FCM Performance Incentives*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_nrg_alternative_proposal_11_16_12_.pdf

ATTACHMENT N-1c

Testimony of Calvin A. Bowie,
Manager, ISO and NEPOOL Relations,
Northeast Utilities
on behalf of NEPOOL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___-000**
New England Power Pool	**)**	

TESTIMONY OF CALVIN A. BOWIE

Q. Please state your name and professional affiliation.

A. My name is Calvin A. Bowie. I am submitting this testimony in my capacity as the elected Participants Committee officer from the Transmission Sector of NEPOOL during the time period when the ISO-NE and NEPOOL Proposals were considered and acted upon through the Participant Processes. I was the elected Participants Committee officer from the Transmission Sector from 2007 through 2013. I was the Chairman of the NEPOOL Participants Committee during 2012 and 2013. I am currently the Manager of ISO and NEPOOL Relations for Northeast Utilities.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with the view of the majority of the NEPOOL Transmission Sector regarding the two market, performance incentive-related proposals ("PI" proposals) before the Commission in this "jump ball" filing.

Q. Who are the current members of the Transmission Sector in NEPOOL?

A. Bangor Hydro-Electric Company, Central Maine Power Company, New England Power Company (a subsidiary of National Grid), Northeast Utilities/NSTAR, The United Illuminating Company, and Vermont Electric Power Company, Inc.

Q. What involvement did the Transmission Sector have in the stakeholder process for the development of the PI proposal?

A. Members of the Transmission Sector were involved in all discussions of the PI proposals during the deliberations of the NEPOOL Markets Committee and Participants Committee and expressed their views during those meetings. In addition to this participation in stakeholder meetings the Transmission Sector met with the ISO-NE Board on June 25, 2013 and November 8, 2013, and conveyed its concerns with the ISO-NE proposal.

Q. What position did the Transmission Sector members take in voting at the Participants Committee on the PI proposals?

A. Among the Transmission Sector all of the members except National Grid opposed the ISO proposal and supported the NRG proposal that became the NEPOOL preferred alternative, and which I refer to herein as the "NEPOOL Proposal". For ease of reference in my testimony by using "Transmission Sector" I refer to the majority of the members of the Transmission Sector who oppose the ISO-NE proposal and support the NEPOOL Proposal.

Q. Why did the Transmission Sector not support the ISO proposal?

A. All members of the Transmission Sector agree that our customers could face reliability concerns and cost issues if sufficient resources are not available to meet their power needs. While all members of our sector support the ISO-NE's reliability goals, most believe the ISO-NE's FCM PI proposal has features that could be unnecessarily expensive, counterproductive and are too significant of a change from the current rules.

There are several reasons why the majority of the transmission owners did not support the ISO-NE proposal.

First, the Transmission Sector believes that the ISO-NE's FCM PI proposal would impose unnecessary expense on consumers by increasing the long-term fixed costs of installed capacity to meet the FCM PI requirements by introducing a substantial and unnecessary risk component into capacity pricing. This expense is unnecessary because it results from solutions to performance issues that are currently being addressed through reforms to the energy and reserves market specified below. Energy and reserve market reforms will better connect increased costs for load to the load that creates the greater demand, and are thus more compatible with the Commission's cost causation principles. The ISO's proposal does not result in that close tie between costs and beneficiaries.

Second, as we came to understand the ISO's proposal better, we viewed it as a solution to a performance problem that was better addressed through the energy and reserves markets rather than through the capacity market. The FCM is intended to be a market that ensures resource adequacy by procuring enough installed capacity to meet the Installed Capacity Requirement ("ICR") for the pertinent Capacity Commitment Period.

The ISO's proposal redefines capacity as a product that can be supplied best by baseload energy resources or fast-start peaking resources. Under ISO-NE's proposal, when a Capacity Scarcity Condition is triggered, only resources that are producing energy or reserves at the time of and during the pendency of the Capacity Scarcity Condition will be able to avoid significant penalties. In reality, the pool of capacity resources in New England includes thousands of megawatts of valuable resources that are neither economically dispatched as baseload resources, nor capable of providing fast-starts. Many of these resources provide substantial reliability benefits to the region, but under the ISO-NE proposal they could be perfectly maintained and respond perfectly to all ISO dispatch instructions, yet still be subject to significant financial penalties because of ISO-NE's redefinition of the capacity product. While there is a need for baseload and fast-start resources, there is not a need to procure such resources in an amount equal to the ICR. Indeed, to do so would be inefficient and unnecessarily expensive for consumers.

While the Transmission Sector does see a need for better performance of capacity resources when called upon, that need is partly being addressed through reforms already made or that are pending in the energy and reserve markets. Those energy and ancillary services market reforms include: modifications to the bidding/offer deadlines in the Day-Ahead Energy Market[1]; changes to permit bidders increased energy offer flexibility, including the opportunity to make hourly intra-day re-offers and to offer energy at negative prices[2]; modifications to permit the use of a Reserve Constraint Penalty Factor

[1] *ISO New England Inc. and New England Power Pool*, 143 FERC ¶ 61,065 (Apr. 24, 2013).

[2] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,014 (Oct. 3, 2013).

(RCPF) of $250/MWh for the replacement reserve requirement in place of normal supplemental commitment[3]; changes to authorize ISO-NE's procurement of additional ten-minute non-spinning reserves in the Forward Reserve Market[4]; changes to generating resource auditing requirements and procedures[5]; changes to the Forward Reserve Market incentives[6]; market mitigation modifications to allow dual-fuel units to take better advantage of fuel switching capability[7]; and expanded authority for ISO-NE to communicate with natural gas pipeline operators[8]. Additional enhancements in the Forward Capacity Market to improve 'performance incentives' of capacity resources include changes to the definition of Shortage Event triggers[9] and clarifications from the Commission in response to the NEPGA Complaint concerning the 'performance' obligations of resources with Capacity Supply Obligations.[10] All of these changes combined with the additional changes proposed in the NEPOOL Proposal, should be implemented and given a chance to address performance issues before major changes are

[3] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1736-000 (Aug. 15, 2013) (unpublished letter order accepting revisions to establish a Reserve Constraint Penalty Factor for the Replacement Reserve Requirement).

[4] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-465-000 (Feb. 8, 2013) (unpublished letter order accepting revisions to Forward Reserve Market Rules to permit the procurement of additional Ten-Minute Non-Spinning Reserve).

[5] *ISO New England Inc. and New England Power Pool*, 142 FERC ¶ 61,024 (Jan. 9, 2013).

[6] *ISO New England Inc. and New England Power Pool*, Docket No. ER13-1733-000 (Aug. 15, 2013) (unpublished letter order accepting revisions concerning Forward Reserve Market incentives).

[7] *ISO New England Inc. and New England Power Pool*, Docket No. ER14-707-000 (Jan. 15, 2014) (unpublished letter order accepting relocation of dual-fuel switching provisions).

[8] *See* Pipeline Information-Sharing Changes, *ISO New England Inc. and New England Power Pool Participants Committee*, Docket No. ER14-970-000 (filed Jan. 10, 2014).

[9] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,095 (Nov. 1, 2013).

[10] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 144 FERC ¶ 61,157 (2013), *order on reh'g*, 145 FERC ¶ 61,206 (Dec. 6, 2013).

made to the FCM, which is intended to ensure resource adequacy not operational performance.

Third, the Transmission Sector believes that the ISO-NE proposal would inappropriately impose penalties on capacity resources for failure to perform even when the reason for non-performance is beyond the control of those resources, or perversely when such resources are responding to ISO dispatch instructions in accordance with their physical operating characteristics. Under the ISO's proposal, transmission outages that result in capacity resources not being able to provide energy and/or reserves to the system would result in FCM penalties even if such transmission outages were fully outside the control of the capacity resource. Similarly, capacity resources could be exposed to penalties for non-performance even though following ISO dispatch instructions operate at a reduced output, or are on an ISO-approved planned maintenance schedule. These kinds of 'non-performance' are not avoidable through additional investment in equipment, and thus the penalties serve no purpose but to penalize. The capacity resources subject to such unavoidable and unhedgeable risks will have no choice but to build a risk premium into their capacity offers thereby raising the costs for all with only the hope of theoretical future benefits. Additionally, penalizing capacity resources for non-performance while on a planned maintenance outage will tend to create a perverse incentive for those resources to do maintenance outside of the ISO's schedule, or to minimize maintenance, thereby putting into jeopardy system reliability. Indeed, the incentive would be to not coordinate maintenance at all.

In actuality, the Transmission Sector is concerned that the ISO's proposal creates higher capacity prices (both for individual resources that will be compelled to hedge future penalties, and for all resources since the auction clearing prices will increase) without substantially incenting changes in behavior. Much of that behavior is outside of a resource owner's control (e.g. when a resource is on a planned outage, following dispatch instructions, or affected by a transmission outage). For an incentive to be valid, it must be tied to behavior changes that can and should be made in response to such incentive. ISO-NE's proposal fails to properly link incentives to behaviors.

Fourth, the Transmission Sector does not support the ISO's proposal because we do not have an adequate understanding of the financial implications to our customers and our companies of implementing FCM PI although, as indicated above, the implications appear to be increased costs without commensurate reliability benefits.

Finally, ISO-NE has repeatedly told stakeholders that the economic foundation of its proposal is to replicate the incentives that would arise in an uncapped energy-only market. Without debating the merits or flaws of an uncapped energy market, the Transmission Sector would point out that ISO-NE's proposal does not replicate the incentives of an uncapped energy market because the ISO-NE proposal includes out-of-pocket penalties in addition to the lost opportunity cost associated with non-delivery during scarcity conditions in an uncapped energy market. These out-of-pocket penalties are a critical distinction. As an example, if in an uncapped energy market a resource does not produce energy during a scarcity event where energy is priced at $1,500/MWh, it loses the opportunity to sell $1,500 energy. Under the ISO-NE proposal, an

underperforming resource would not only face a lost opportunity cost of $1,500/MWh, it would also pay a penalty of $2,000/MWh. Thus the total cost to the resource owner is $3,500/MWh, $2,000 of which is out-of-pocket in the form of penalties.

Q. Why does the Transmission Sector support the NEPOOL Proposal?

A. The Transmission Sector's support for the NEPOOL Proposal came about largely because it avoids some of the problems we saw with the ISO's FCM PI proposal, while providing a more incremental and targeted solution to ensuring the performance of capacity resources when most needed. The final NEPOOL Proposal did not get the same degree of scrutiny and input as did the ISO's proposal, although the basic framework was part of the discussions throughout the year-long stakeholder process. Nevertheless, the NEPOOL Alternative was acceptable to the Transmission Sector and is preferable to the ISO's proposal.

There are several reasons why this is the case. First, the NEPOOL Proposal focuses its reforms to enhance performance where they should be focused, in the energy and reserves markets. The NEPOOL Proposal treats installed capacity as it was intended, capacity available to meet the resource adequacy criterion of loss of load no more than one day in ten years. Short term performance and energy delivery issues are appropriately addressed through the short term energy and ancillary services markets, and that is what the NEPOOL Proposal does.

Second, by targeting its reforms in the energy and reserves markets, the NEPOOL Proposal targets costs of enhanced performance in a more accurate way both temporally

and locationally, primarily through real time reserve prices and LMPs created by the scarcity of reserves on the system. Because of its ability to better target costs of enhanced performance to the load that causes those costs, the NEPOOL Proposal is both more consistent with fundamental cost causation principles and more likely to include load in the solution to short-term reliability needs on the system as load sees price signals and responds accordingly.

Third, the NEPOOL Proposal provides additional performance incentives for capacity resources but does not contain the unreasonable penalties that would be imposed under the ISO's proposal. There would be no penalties for unavailability due to transmission outages, which is appropriate because those outages are beyond the capacity resource's control. There are no penalties for unavailability due to planned maintenance, which is entirely appropriate given that the purpose of such maintenance is to help maintain reliability. Also, the NEPOOL Proposal does not penalize resources for following ISO dispatch instructions, which again avoids sending the wrong signal to capacity resources that could be counterproductive to maintaining reliability.

Finally, the NEPOOL Proposal will allow for sound analysis of the reliability and financial effects of its incremental changes, so that the ISO, NEPOOL, the states and other stakeholders can determine what else, if anything is needed to be added or adjusted to ensure the performance of capacity resources in the New England markets.

For all of these reasons, the Transmission Sector opposes the ISO's proposal and supports the NEPOOL Proposal.

Q. Does that conclude your testimony?

A. Yes, it does.

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

Calvin A. Bowie

Executed on: January 17, 2014

ATTACHMENT N-1d

Testimony of Brian E. Forshaw,
Chief Regulatory and Risk Officer,
Connecticut Municipal Electric Energy Cooperative,
on behalf of NEPOOL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___-000**
New England Power Pool	**)**	

TESTIMONY OF BRIAN E. FORSHAW
NEPOOL PARTICIPANTS COMMITTEE
PUBLICLY OWNED ENTITY SECTOR VICE-CHAIR

I. BACKGROUND AND QUALIFICATIONS

Q. Please state your name and professional affiliation.

A. My name is Brian E. Forshaw. I am the Chief Regulatory and Risk Officer for the Connecticut Municipal Electric Energy Cooperative ("CMEEC"), a joint-action power supply agency organized pursuant to the Connecticut General Statutes to secure reliable and low cost power supplies for municipal electric utilities, where I have been employed for over 33 years. My place of business is 30 Stott Avenue, Norwich, Connecticut, 06360-1526.

Q. Please summarize your relevant professional background.

A. My primary responsibilities at CMEEC include representing CMEEC and other Publicly Owned Entities[1] in matters before the New England Power Pool ("NEPOOL") and before various State and Federal regulatory and legislative forums. Additional responsibilities at CMEEC have included overseeing all aspects of CMEEC power supply activities, including risk management, long-term resource planning, strategic planning and contract negotiations.

In my over 33 years at CMEEC, I have directly participated, on behalf of New England's consumer-owned power systems, in virtually all of the efforts undertaken by NEPOOL and ISO-NE to restructure and refine New England's wholesale electric markets. This

[1] Capitalized terms not defined in this Affidavit have the meanings ascribed thereto in NEPOOL's transmittal letter in this proceeding, the Second Restated NEPOOL Agreement, Participants Agreement, or the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff ("ISO-NE Tariff").

has included service on, among others, NEPOOL's Technical Committees and its Participants Committee. I am currently the elected representative of the Publicly Owned Entity Sector and serve as a Vice-Chair of the Participants Committee, an office I have held since 2002. I served as Chairman of the Participants Committee for 2008 to 2009. I believe that this direct experience gives me a unique perspective from which to assess and evaluate the Forward Capacity Market Performance Incentive ("FCM PI") proposals before the Commission in this "jump ball" filing.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with CMEEC's perspective, which also represents the perspective of those members of the Publicly Owned Entity Sector that carried the vote of the Publicly Owned Entity Sector, regarding the two FCM PI proposals before the Commission in this proceeding.

III. PUBLICLY OWNED ENTITY SECTOR PARTICIPATION IN THE STAKEHOLDER PROCEEDINGS PRECEDING THE FILING OF THE FCM PI PROPOSALS

Q. Who are the current members of NEPOOL's Publicly Owned Entity Sector?

A. Each of the 55 members of the Publicly Owned Entity Sector[2] is an Entity which is either a municipality or an agency thereof, or a body politic and public corporation created under the authority of one of the New England states, authorized to own, lease and operate electric generation, transmission or distribution facilities, or an electric cooperative, or an organization of any such entities. Publicly Owned Entities participate in New England's electric markets primarily to serve their needs, or the needs of its member municipal utilities, as the case may be.

[2] A comprehensive list of the 55 members of the Publicly Owned Entity Sector and the 57 companies they represent can be found on NEPOOL's website at http://nepool.com/uploads/C-Sector_Roster.pdf.

Q. What involvement did the Publicly Owned Entity Sector have in the stakeholder process for the development of the FCM PI proposals?

A. Members of the Publicly Owned Entity Sector were involved in all discussions of the FCM PI proposals that occurred at NEPOOL's Principal Committees and expressed their views during those meetings. In addition to this participation in stakeholder meetings, the Publicly Owned Entity Sector conveyed its concerns with the ISO-NE proposal during meetings held with members of the ISO-NE Board on June 25, 2013 and November 8, 2013.

Q. What position did Publicly Owned Entity members take in voting at the Participants Committee on the FCM PI proposals?

A. 38 members of the Publicly Owned Entity Sector were present for the Participants Committee votes on the FCM PI Proposals. All of those members opposed the ISO-NE Proposal. With respect to the NEPOOL Proposal, all members not abstaining voted to support the NEPOOL Proposal, with the Massachusetts Municipal Wholesale Electric Company ("MMWEC"), and each of the Participant members it represented, abstaining on the vote on the NEPOOL Proposal.[3] Accordingly, for purposes of this Affidavit, reference to Publicly Owned Entity Sector in the discussion of the Sector's position on the ISO-NE Proposal is indicative of the position of each of the 38 members. With respect to the Publicly Owned Entity Sector's position on the NEPOOL Proposal, this Affidavit will, as noted above, present CMEEC's specific perspective, as representative of the perspective of those Sector members that carried the Publicly Owned Entity Sector's votes on the two FCM PI proposals before the Commission in this proceeding.

[3] *See* NEPOOL transmittal letter, Attachment N-1h.

IV. PUBLICLY OWNED ENTITY SECTOR OPPOSITION TO THE ISO-NE PROPOSAL

Q. Why did the Publicly Owned Entity Sector not support the ISO-NE Proposal?

A. The bases for opposition by the Publicly Owned Entity Sector to the ISO-NE Proposal can be summarized as follows:

- ***The ISO-NE Proposal is Unnecessary at this Time.*** The ISO-NE Proposal is unnecessary at this time because the concerns it purports to address are already being addressed through other means. Before adopting yet another "solution," the Commission should ensure that the concerns that motivate the ISO-NE Proposal are not already being addressed. ISO-NE's Wholesale Markets Plan commits New England to a set (10-12) of major energy and operating reserve market enhancements over the next 2-3 years that are aimed at the same concerns offered to justify the ISO-NE Proposal.[4] Changes that are already in place or in the pipeline include:
  - Expanding the definition of shortage event to "incentivize" better resource performance;
  - Energy market supply offer flexibility to help generators better communicate to ISO-NE and recover actual fuel costs;
  - Increased operating reserve requirements to bolster system reliability;
  - Stiffer penalties for generators that fail to perform consistent with reserve commitments;
  - Stricter generator auditing requirements to help ensure capacity commitments match availability;
  - Modifying how constraints are treated in the unit commitment software for the Day-Ahead Energy Market to produce a Day-Ahead commitment

[4] The latest, updated ISO-NE Wholesale Markets Project Plan, which describes the key market initiatives underway and planned for the upcoming three years to ensure an efficient and reliable electricity system in New England, is available at: http://www.iso-ne.com/pubs/whlsle_mkt_pln/.

schedule that is more closely aligned with what will be needed in Real-Time.

- Day-Ahead Energy Market time shift to better align the electric market with the gas trading day;
- Sub-hourly generating resource energy settlement, which will make real-time generating resource incentives more precise and targeted to short periods of reserve scarcity (slated for 2015 implementation);
- Expanded communication between electric and natural gas markets;
- Clarification by the Commission about the obligations of generators with capacity market obligations to procure fuel to meet Day-Ahead and Real-Time Energy Market commitments, meaning that they cannot make an economic decision not to procure fuel, but can be excused only if fuel is not physically available;[5]
- ISO has included implementation of a downward-sloping demand curve in their latest Wholesale Markets Plan update; and
- It now appears that FCA8 may clear at a higher level than in prior auctions, providing a source of revenues for generators to meet their obligations on a going forward basis.

Importantly, many of the changes noted above appear to be achieving their desired result. For example, ISO-NE has indicated that it does not believe that there will be a need for a supplemental fuel procurement reliability program for the Winter 2014/2015 period or beyond.[6] While still early to form a firm

[5] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 144 FERC ¶ 61,157 (2013) (finding that "a capacity resource that fails to comply with dispatch instructions when it is physically available but has determined not to procure fuel or transportation due to economic considerations is in violation of the Tariff." *Id.* at P 58).

[6] *See* "Winter 2014-15 Solutions Update", ISO-NE presentation to NEPOOL Markets Committee (Nov. 13, 2013 meeting), available at: http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a11_iso_presentation_11_13_13.ppt.

conclusion, in his monthly report at the January 10, 2014 NEPOOL Participants Committee meeting, the ISO-NE Chief Operating Officer noted that recently it appears that a greater percentage of the Real-Time Load Obligation is being scheduled and clearing in the Day-Ahead Energy Market.[7]

- ***The ISO-NE Proposal Will Cost Consumers More Than the Value of any Offsetting Benefits.*** The ISO-NE Proposal will raise consumer costs without a concomitant increase in benefits. To the contrary, in fact, the ISO-NE Proposal is already adversely impacting the New England market. Reasons for those adverse impacts include:

  - The ISO-NE Proposal fails to address the challenges at the heart of the issues ISO-NE is purportedly seeking to resolve (i.e. longstanding problems in Energy and Operating Reserve Market pricing, as documented by ISO-NE's External Market Monitor and various stakeholders and ISO-NE's October 2012 Whitepaper;

  - The mere possibility that the ISO-NE Proposal will be implemented has already accelerated the exit of older, relatively less flexible (but nonetheless valuable) existing resources from the system, and appears to have been the reason for a number of potential new resources to withdraw from the qualification process for the eighth Forward Capacity Auction (FCA8); and

  - ISO-NE Proposal-induced Resource retirements have accelerated the date when new (and more expensive) Resources will be needed to clear the FCM,[8] increasing the likelihood that those Resources, or import

[7] See "NEPOOL Participants Committee Report January 2014", Vamsi Chadalavada, Executive Vice President and Chief Operating Officer (Jan. 10, 2014), available at: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2014/jan102014/coo_report_jan_2014.pdf.

[8] These retirement concerns exist today: 3,135 MW of existing Resources (generation and demand response ("DR") resources) submitted Non-Price Retirement ("NPR") requests for the FCA8 commitment period (2017/2018). As reported by the ISO-NE Chief Operating Officer at the April 2013 Participants Committee meeting, a total of 6,630 MW of new Resources submitted Show of Interest

transactions will set the FCA8 clearing price at a level substantially above the FCA7 clearing price of $3.15 per kW-mo. Given the level of Non-Price Retirements recently announced, it now appears that costs to consumers will go up by $15-$30 per MWh in June 2017, unless Insufficient Competition Rules end up being triggered.

- ***The ISO-NE Proposal Will Decrease Resource Participation and Increase Consumer Costs***. ISO-NE and its consultants appear to believe that the possibility of performance payments under the FCM PI construct will increase the amount of resources that will participate in the capacity market and will reduce the level of capacity payments required from the FCM. Contrary to ISO-NE's belief and the results of the study by the Analysis Group, the prospect of substantial penalties will not only restrict FCM participation, but will result in those units that do choose to participate in the Forward Capacity Auctions seeking higher premiums to compensate for the added risks associated with the ISO-NE Proposal. Asset owners and operators (including CMEEC and others from the Publicly Owned Entity Sector) place substantially more weight on exposure to performance penalties than they place on the "upside" of receiving a share of the non-delivery penalty payments made by other asset owners and operators. This is even more significant when considering the fact that exposure to such penalties is directly related to factors beyond control of the asset owner. Even if we accept the potentially understated estimates from ISO-NE's Analysis Group study, additional risk premiums associated with the implementation of the ISO-NE Proposal would drive up consumer costs to load by another $10-$12 per MWh.

V. SUPPORT FOR THE NEPOOL PROPOSAL

Q. Particularly in light of your response to the ISO-NE Proposal, could you please summarize why CMEEC supported the NEPOOL Proposal?

A. CMEEC supported the NEPOOL Proposal because it adopts a more measured approach to address the problems underlying resource performance. The NEPOOL Proposal seeks

("SOI") requests for FCA8 and only 2,126 MW, representing 61 new projects, decided to remain in the auction through the qualification process.

to build upon efforts already underway to address ISO-NE resource performance concerns without subjecting the region to the unintended consequences and substantially increased costs discussed above. The NEPOOL Proposal is focused on the "root cause" of ISO-NE's concerns by directly addressing pricing problems in the energy and operating reserve markets. Subject to further refinement, the NEPOOL Proposal could potentially be implemented well in advance of FCA9, the earliest possible date when the ISO-NE Proposal could be implemented. To the extent additional "insurance" is needed, an incremental firm energy procurement could be pursued for a subset of Resources (rather than the entire generation fleet) needed to address ISO-NE operational concerns.

VI. CONCLUSION

Q. As Vice-Chair of the Publicly Owned Entity Sector, what is your conclusion with respect to the FCM PI Proposals?

A. As indicated by the December 6, 2013 vote of the Publicly Owned Entity Sector, the Commission should not approve the ISO-NE Proposal.

Q. As Vice-Chair of the Publicly Owned Entity Sector, what is your recommendation with respect to the FCM PI Proposals?

A. As between the alternatives presented in this proceeding, having considered the potential impacts of each, I believe the better course would be to implement the NEPOOL Proposal. The Commission should permit the NEPOOL Proposal, as well as other planned Market Rule and market design changes, a chance to demonstrate their effectiveness in achieving their intended objectives, including incenting resource performance, before ordering or directing a fundamental change to the region's market design. Following a reasonable opportunity for such demonstration, the Commission can thereafter evaluate overall market and resource performance and direct, if and as appropriate, consideration or implementation, following appropriate stakeholder process, of any changes or improvements thereto.

Q. Does that conclude your testimony?

A. Yes, it does.

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

Brian E. Forshaw

Brian E. Forshaw

Executed on: January 16, 2014

ATTACHMENT N-1e

Testimony of Elin S. Katz,
Consumer Counsel,
Connecticut Office of Consumer Counsel,
on behalf of NEPOOL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___000**
NEPOOL Participants Committee	**)**	

Testimony of Elin Swanson Katz, Connecticut Consumer Counsel
for the NEPOOL Participants Committee

Q. Please state your name, title, business address, and affiliation with the NEPOOL Participants Committee.

A. My name is Elin Swanson Katz, Connecticut Consumer Counsel, appointed by Connecticut Governor Dannel P. Malloy to lead the Connecticut Office of Consumer Counsel ("OCC") for a five-year term that began on October 3, 2011. OCC is in the End-User Sector of the New England Power Pool ("NEPOOL") Participants Committee. My business address is 10 Franklin Square, New Britain, Connecticut 06051. OCC is Connecticut's statutory advocate for utility customers pursuant to our enabling statute, Connecticut General Statutes § 16-2a. This enabling statute authorizes OCC to act on behalf's of the state's electric customers in any regulatory or judicial proceedings which may affect their interests, including matters before the Federal Energy Regulatory Commission.

Q. What is the purpose of OCC's testimony?

A. The purpose of this testimony is to give OCC's perspective, in our capacity as a member of the End-User Sector of NEPOOL, about two sets of proposed changes to the wholesale electric market rules in New England. These markets are administered by the regional transmission organization, ISO-New England, Inc. ("ISO-NE"). OCC's perspective has been informed in part by discussions with many stakeholders, including fellow consumer advocates, public utility commissions, capacity suppliers, investor-owned utilities, and municipal utilities.

Q. Please describe the two sets of proposed market rule changes at issue.

A. The first set of proposed changes, being filed by ISO-NE, is usually referred to as the Performance Incentives ("PI") proposal, although it is sometimes referred to as "Pay for Performance." Its stated purpose is to significantly change the rules in the Forward Capacity Market ("FCM") to provide greater financial incentives to capacity resources to improve their performance and operating flexibility, particularly during times of system stress. The second set of proposed changes is based on market reforms initially advanced by generation owner NRG and ultimately supported, as amended, by OCC and a significant majority of the NEPOOL Participants Committee ("NEPOOL Proposal"). The NEPOOL proposal also seeks to improve resource performance, but it would do so by making adjustments to rules for the real-time energy market and the operating reserve market, as well as by making much less drastic changes to the FCM than are being proposed by ISO-NE. This testimony will explain why OCC supports the NEPOOL Proposal and opposes ISO-NE's PI proposal.

Q. Were ISO-NE's PI proposal and the NEPOOL Proposal considered by the NEPOOL Participants Committee?

A. Yes, both proposals were considered by the NEPOOL Participants Committee. ISO-NE's PI proposal failed at the NEPOOL Participants Committee with only 10.28% in favor. The NEPOOL Proposal was supported by the NEPOOL Participants Committee with 80.28% in favor.

Q. How did OCC vote as to the two sets of proposals?

A. OCC voted to support the NEPOOL Proposal and to oppose ISO-NE's PI proposal.

Q. Why did OCC vote "no" on ISO-NE's PI proposal?

A. OCC voted "no" on the PI proposal because OCC has concluded, based on discussions with stakeholders and its own analysis, that the PI proposal will lead to unjust and unreasonable increases in capacity costs for customers and will not likely provide any reliability gains in return for those significant cost increases. Indeed, instead of

promoting reliability, OCC is concerned that the new risks created by the PI approach may lead to premature power plant retirements that immediately and materially threaten reliability in some sub-areas of the New England system. These reliability threats may persist because new investment is not likely to occur with PI in place.

Q. Does OCC agree with ISO-NE that under the current FCM construct, some units are getting all or a significant share of their annual capacity payments despite poor performance?

A. OCC does not dispute ISO-NE's representation that a small number of units may be getting "money for nothing" under the current FCM construct. However, concerns about a small percentage of capacity suppliers do not justify a sweeping rule change like PI. In addition, OCC disagrees with PI remedy because it will create an excessively risky environment for existing suppliers as well as for investors and developers of new power plants and demand-side resources, at a time when such new investment will soon be needed.

Q. Why does OCC view PI as creating an excessively risky investment environment for capacity?

A. PI creates excessive investment risk because, among other things, PI's substantial penalties would impact capacity suppliers that are not operating during particular five-minute intervals regardless of the reason why they were not operating. PI would ignore the actual operating characteristics of a power plant when levying penalties. For example, PI would harshly punish a generation unit that bids its energy into the day-ahead market, is not given day-ahead dispatch instructions by ISO-NE based on the market clearing process, and is then physically unable to produce in real-time based on its operating characteristics. Thus, under PI, a unit that is available to operate but is not dispatched by ISO-NE because of its economics will be penalized solely because it was more costly in the day-ahead market to operate, not because of its ability or willingness to perform. While this may have surface appeal to ISO-NE and perhaps others, as an impetus for development of more flexible resources, it gives insufficient regard to the fact

that every reliable and cost-effective power system requires a diverse mix of generation units. At a minimum, we expect that PI will complicate and increase the costs of financing new generation units and further reduce the chance that the capacity market is able to support the development of generation supplies when needed, where needed, and at a reasonable price.

Both ratepayers and merchant developers of new capacity have an enormous interest in ensuring that the financing of new generation plants is not excessively costly or risky. We are already seeing some significant retirements and planned retirements in New England's generation fleet, the output of which will need to be replaced by new capacity resources, including power plants. New merchant plants cannot be financed on reasonable terms or rates when new rules are drastically changing market designs and adding excessive performance risks. Under PI, we are persuaded based on discussions with developers and other stakeholders that new plants will either not be able to be financed, exacerbating a potential shortage, or would only be financed at an excessive cost. To the extent that new resources are financed and seek to participate in the capacity market, these financing costs would flow to ratepayers through capacity market offers setting the market-clearing price. Moreover, it is plausible that a plant that is needed for reliability and cannot manage its financing costs may need a ratepayer Reliability-Must-Run "backstop" to avoid bankruptcy. Thus, financing risks and costs impact both suppliers and ratepayers.

In addition, the "forward" nature of the Forward Capacity Market, coupled with the strict penalty approach in PI (penalties imposed regardless of fault), would add significant risk for capacity suppliers. A capacity supplier bidding into FCM in Year 1 may find in Year 4, when its responsibilities begin, that its ability to deliver capacity has been diminished by circumstances beyond its control, such as delays of transmission upgrades, reduced access to fuel, new environmental rules, and further changes to market rules. Although these risks would exist in any <u>forward</u> capacity market, the radically changed penalty structure in PI renders these uncontrollable risks harder for a capacity supplier to bear. This again will cause suppliers to raise their FCM bids and, in turn, raise consumer costs.

Q. Why are excessive risks for capacity suppliers under PI a potential reliability problem for customers?

A. PI presents a potential reliability problem because capacity suppliers may conclude that the risks of penalties under the PI proposal are too high, and those suppliers may either exit the market or decline to enter it. Based on discussions with capacity suppliers and their public comments, OCC is persuaded that suppliers generally fear a loss of $X in a year as a result of PI much more than they savor a gain of the same $X in a year, reflecting the likelihood that such suppliers, like humans generally, are more risk-averse than economic models assume. Thus, even when the PI proposal leads to symmetric gains for those who produce and penalties for those who fail to produce (and it will not always do so), this design will be viewed by risk-averse suppliers as a dangerous path, not an appealing opportunity to earn additional revenue. A more volatile set of FCM outcomes, resulting from the high penalties of PI, may create both retirements and financing difficulties, threatening reliability.

Q. But would you agree that ISO-NE has adjusted the PI proposal to limit risks for capacity suppliers?

A. ISO-NE has adjusted the PI proposal in an attempt to address risks, but the fundamental and insurmountable problems with PI remain. The adjustments were (i) a phase-in of the amount of the performance payment rate ("PPR," the figure which determines the penalty and reward for performance); and (ii) adding an annual stop-loss mechanism to the previously-proposed monthly stop-loss provision in the proposal, limiting what a capacity supplier can lose in a year from FCM participation. However, the PI proposal is still hampered by the fundamental problem that it holds capacity suppliers responsible for severe penalties for events beyond their control. It also still penalizes capacity suppliers if, based on operating characteristics, they are physically unable to respond in real-time when not committed in the day-ahead market or when they are not economically dispatched.

Q. Why do you prefer the NEPOOL Proposal to ISO-NE's PI proposal?

A. OCC has evaluated several potential alternatives to PI and finds that the NEPOOL Proposal is an acceptable alternative and a significant improvement over the PI proposal. OCC evaluated the PI proposal and alternatives throughout 2013. We had discussions with numerous stakeholders, including state parties, municipal utilities, investor-owned utilities, and generators, about a potential alternative to PI called Premium Capacity-Plus. The Premium Capacity-Plus proposal would have promised greater rewards and potential penalties to a subset of capacity suppliers (representing about 10-20% of available capacity) who were willing and able to respond in real-time to ISO-NE dispatch instructions. In this way, the Premium Capacity-Plus proposal sought to improve availability of resources at peak times and address the variability between expected load and actual loads. Premium Capacity-Plus also included changes to the energy and operating reserve markets. Despite OCC's support of the Premium Capacity-Plus proposal, it was not approved in the NEPOOL process.

OCC continued to explore other alternatives to PI, however, and continued to work with a variety of stakeholders. Among various proposals and approaches suggested by parties was a proposal by NRG, which like Premium Capacity-Plus, primarily sought to correct a small number of broadly-recognized problems with price formation in the energy and reserves markets, as opposed to the fundamental redesign of the capacity market sought through PI. Those energy and reserves market changes would increase economic incentives to make commitments in the day-ahead market and would improve performance in real time. By avoiding radical changes to FCM, we anticipated that NRG's proposal would create lower financing costs for necessary new capacity developments, while also creating what may be more rational outcomes in the energy market, even under scarcity conditions. Through discussions among OCC, other consumer advocates, public utility commissions, NRG and other generator interests, and others, certain revisions and refinements were made to NRG's plan. These revisions included a zonal approach to allocation of FCM penalties and rewards, known as "Availability Adjustments," and tightened restrictions on continuing FCM participation by Poorly Performing Resources. With these revisions, OCC was able to support the

proposal, referred to herein as the "NEPOOL Proposal," as a package of market rule adjustments that is a viable and preferable alternative to PI.

Q. Why do you say that NRG's approach, now the NEPOOL Proposal, addresses broadly-recognized problems with price formation?

A. Parties with diverse interests and significant experience in the regional markets, including such entities as NRG and CMEEC, have identified problems in coordination between the day-ahead and real-time markets, including underbidding by some load interests in the day-ahead market followed by higher loads in real-time.[1] This in turn may create the need for ISO-NE to take more frequent out-of-market actions, such as declarations of emergency conditions, that limit the real-time price of energy in the market. At a minimum, this situation often creates the need for uplift charges, which also limit the degree to which the real-time energy price reflects scarcity conditions. Another change included in the NEPOOL Proposal would raise the Reserve Constraint Penalty Factors ("RCPF") for two operating reserve products, and OCC has concluded that this approach would create a more accurate real-time price and greater incentives for availability and production by capacity suppliers during scarcity conditions.

Q. Isn't OCC concerned about higher real-time energy prices?

A. Of course we are concerned about higher energy prices, both because of the direct consumer impact and the possibility for the exercise of supplier-side market power. The specter of supply-side market power in New England markets is an issue that has not been discussed as frequently in the last few years of capacity excess, but it is always a serious potential concern. That said, generators need appropriate incentives and the ability (though not a guarantee) to recover their fixed and variable costs, along with a reasonable rate of return, if they operate reliably. NRG and others have raised at NEPOOL some concerns about price suppression caused by out-of-merit dispatch and other reliability actions by ISO-NE that are not reflected in the real-time price. OCC

[1] CMEEC March 27 Memorandum – Input for Apr. 2, 2013 Joint Meeting on Winter Operations, available at: http://www.isone.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr22013/a2_cmeec_winter_13_14_reliability_solutions_proposal_04_02_13_r1.docx.

appreciates ISO-NE's efforts and the difficult job that ISO-NE has in ensuring system reliability, but also recognizes the point that the current rules have possibly led to excessive dampening of the energy market incentives for operating during scarcity conditions. In addition to the specific RCPF adjustments, the NEPOOL Proposal calls generally for consideration of market rule changes to address these and other price formation issues, as well as the exploration of some ancillary service products to better support load-following and other operational requirements and thereby improve response to contingencies. Although load and generator interests are not always aligned, the mutual interest of load and suppliers in: (i) reducing the risks of participation in the ISO-NE-administered markets; (ii) reducing the financing costs of new investment; and (iii) avoiding premature retirements, coupled with a recognition of the serious issues the region faces, creates a real opportunity to develop reasonable solutions to price formation issues that benefit both load and suppliers.

Q. Does OCC support the "Equivalent Peak Period Forced Outage Rate" or "EFORp" approach?

A. OCC does favor the EFORp approach as part of the NEPOOL Proposal package. The EFORp proposal would provide greater incentives for units to be available during historically critical hours of the day in June through August, December, and January. Unlike the PI proposal, the EFORp proposal would not punish generators for failures to deliver that are beyond their control. The EFORp approach would also recognize the different operating characteristics of different units, and would reward or punish units based on a comparison to their previously-established level of performance. The rewards and punishments of the EFORp approach are significant (1.5 times the clearing price times the level of under- or over-performance), but not as potentially severe and certainly not as unpredictable and uncontrollable as the reward and penalty approach in PI.

Q. Does the NEPOOL Proposal do anything about the identified problem of some units receiving "money for nothing" in the capacity markets?

A. The NEPOOL Proposal does address the "money for nothing" issue. A resource with two annual availability scores of 40 percent or less in quick succession (over four Capacity Commitment periods or over the most recent three years in which the resource assumed a Capacity Supply Obligation) would be declared a Poorly Performing Resource. A Poorly Performing Resource would be restricted from participation in FCM for several years or until it can demonstrate to ISO-NE that the reason for poor performance has been remedied. In this way, a unit that is not available would be precluded from continuing to supply capacity.

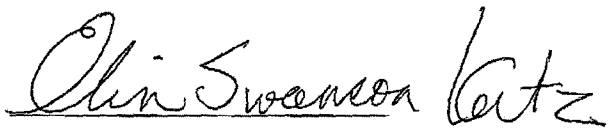
Q. Do you have any additional thoughts about the NEPOOL Proposal?

A. Some parts of the NEPOOL Proposal included specific tariff changes, while other parts call for consideration of market rule changes, including for real-time energy price formation, with the tariff language and other details still to be worked out among NEPOOL stakeholders. We do not claim that the NEPOOL Proposal is perfect, and certainly the less specific portions need to be "fleshed out" with further dialogue. That said, OCC is quite comfortable advocating in favor of the NEPOOL Proposal as a package of changes that are preferable to ISO-NE's PI approach.

Q. Does this conclude your testimony?

A. Yes.

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



Elin Swanson Katz

Executed on: January 17, 2014

ATTACHMENT N-1f

Affidavit and Report of Richard D. Tabors, Ph.D.
on behalf of NEPOOL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER14-___-000**
New England Power Pool	**)**	

AFFIDAVIT OF RICHARD D. TABORS, Ph.D.
ON BEHALF OF THE NEW ENGLAND POWER POOL

I, Richard D. Tabors, Ph.D., hereby state as follows:

I. QUALIFICATIONS AND EXPERIENCE

1. I am a Senior Consultant at Greylock McKinnon Associates, an economics consulting group located in Cambridge, Massachusetts and President and principal of Across the Charles, an economic and engineering consulting group also located in Cambridge, Massachusetts. From November 2004 until June 2012, I was a Vice President of Charles River Associates ("CRA") and for multiple years co-head of the Energy & Environment Practice. From 1989 until 2004, I was the founder and President of Tabors Caramanis & Associates, which was sold to CRA in 2004.

2. From 1976 until 2005, I was a member of the research staff and teaching faculty of Massachusetts Institute of Technology ("MIT") where I was Assistant Director of the Laboratory for Electromagnetic and Electronic Systems (MIT's power systems engineering group) and Deputy Director of the Technology & Policy Program within the School of Engineering.

3. I have spent much of my professional career at the interface between economics and engineering, primarily in the design and implementation of markets and market investment decisions in the electric power sector. With Fred C. Schweppe, Michael C. Caramanis and Roger E. Bohn, I co-authored Spot Pricing of Electricity, which is generally considered the basic theoretical text for the design of electric energy and transmission markets worldwide. My resume is attached as Attachment "*N1-f.b*" to this Affidavit.

4. During my professional career, I have provided expert testimony in over 50 legal matters throughout the United States, and internationally, including arbitrations, proceedings before the Federal Energy Regulatory Commission ("FERC" or the "Commission"), state regulatory commissions and before the United States Congress in matters related to energy, the development of power projects, and the decisions to invest in the electric energy market.

II. TASKS AND MATERIALS REVIEWED

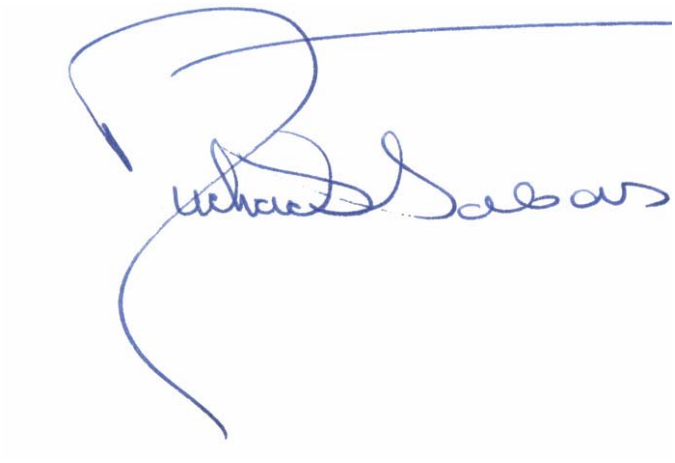
5. I was asked by the New England Power Pool ("NEPOOL") to review and comment on two versions of proposed changes to wholesale electric market rules governing payments for capacity. The alternative put forth by ISO-New England, Inc. ("ISO-NE") fundamentally re-defines the capacity product provided for in the Forward Capacity Market ("FCM") by emphasizing real-time performance through the creation of a new financial incentive / penalty structure that would apply during any defined Capacity Scarcity Condition ("ISO-NE Proposal"). The alternative put forth by NEPOOL increases the Reserve Constraint Penalty Factors and eliminates the concept of a Shortage Event by replacing it with an equivalent peak-period forced outage rate ("EFORp") mechanism.

6. In response to that request, I prepared a report that I entitled "Report on Two Proposals for Performance Incentive Revisions to the ISO-NE Markets: ISO-NE AND NEPOOL." I have attached a copy of my Report to this Affidavit as Attachment "*N1-f.a*". The Report is true and accurate to the best of my knowledge, belief and information. My Report reflects two key observations. First, I review two examples of the outcomes produced under the ISO-NE Proposal, which leads to the inevitable conclusion that the Proposal has a logic flaw that would produce unjust and unreasonable outcomes. As explained in my Report, while the concept brought forward by ISO-NE may provide for greater incentives for performance on the part of those entities with Capacity Supply Obligations ("CSO"), it is neither just nor reasonable in the manner in which real-time performance incentives are calculated or payments and penalties allocated. ISO-NE has proposed a structure to achieve its objective that defies economic logic in a number of

critical ways; provides payments and imposes penalties in unjustified circumstances; and explicitly (and apparently intentionally) does not reflect cost causation. Further, the ISO-NE proposal levies a high cost burden on New England consumers with little if any demonstrated benefit.

7. Second, I offer my observations on the NEPOOL Proposal, which I conclude is preferable to ISO-NE's Proposal. I explain that the NEPOOL Proposal provides an evolutionary approach to increase real-time performance incentives based upon the current structure of the FCM and the real-time markets, offers primarily positive incentives directly in the markets where they are most appropriate, and reinforces the economic market signals that are the underpinning of the wholesale electricity market design objective.

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



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Richard D. Tabors, Ph.D.

Executed on: January 16, 2014

REPORT ON TWO PROPOSALS FOR PERFORMANCE INCENTIVE REVISIONS TO THE ISO-NE MARKETS: ISO-NE AND NEPOOL

Richard D. Tabors, Ph.D
Senior Consultant
Greylock McKinnon Associates
Cambridge, MA 02142

Background

I have been asked by the New England Power Pool (NEPOOL) to review and comment on two versions of proposed changes to wholesale electric market rules governing payments for capacity. The alternative put forth by ISO-New England, Inc. (ISO-NE) fundamentally re-defines the capacity product provided for in the FCM by emphasizing real-time performance through the creation of a new financial performance incentive / penalty structure that would apply during any defined period with a capacity scarcity condition (ISO-NE Proposal). The alternative put forth by NEPOOL increases the Reserve Constraint Penalty Factors and eliminates the concept of a Shortage Event by replacing it with an equivalent peak-period forced outage rate (EFORp) mechanism.

I understand that changes to the structure of the capacity market to better incent Resources were the subject of considerable debate within the NEPOOL stakeholder process. The NEPOOL Proposal was supported and approved by a 80.2% vote of the Participants Committee while ISO-NE's Proposal failed with just 10.28% of the Participants Committee voting in favor.

Both proposals are being submitted to the Federal Energy Regulatory Commission (Commission or FERC) for consideration. I make two key points in this report (Report). First, I describe and discuss the implications of what I perceive to be a logic flaw in the ISO-NE Proposal that results in unjust and unreasonable outcomes. In this regard, I note that I am offering comments relative to my reaction to the specifics of ISO-NE's Proposal and will provide further comment once I have had the opportunity to review ISO-NE's supporting rationale which I expect will be provided by ISO-NE in its filing supporting its proposal. Second, I offer my observations as to why I believe the NEPOOL Proposal is preferable to ISO-NE's Proposal.

Summary

My report concludes that while the concept brought forward by ISO-NE may provide for greater incentives for real-time performance on the part of those entities with Capacity Supply Obligations (CSO), it is neither just nor reasonable in the manner in which real-time performance incentives are calculated or payments and penalties allocated. ISO-NE has proposed a structure to achieve its objective that defies economic logic in a number of critical ways; provides payments and imposes penalties in

unjustified circumstances; and explicitly (and apparently intentionally) does not reflect cost causation. Further, the ISO-NE Proposal would levy a high cost burden on New England consumers with little if any demonstrated benefit.

In contrast, the NEPOOL Proposal would provide an evolutionary approach to increase real-time performance incentives based upon the current structure of the FCM and the real-time markets, offer primarily positive incentives directly in the markets where they are most appropriate, and reinforce the economic market signals that are the underpinning of the ISO-NE wholesale electricity market design objective.

The discussion that follows reviews the current structure of the Forward Capacity Market and its implementation; summarizes the ISO-NE Proposal based on the October 2012 ISO-NE white paper on FCM performance Incentives circulated by ISO-NE[1]; highlights with specific examples the near fatal and fatal flaws of the ISO-NE Proposal, and then reviews and compares the NEPOOL Proposal with that of ISO-NE.

Summary of the ISO-NE Current Rules for Rewarding Real-Time Performance and Non-performance of Resources

To better understand the changes proposed by ISO-NE, it is necessary to understand, even at a relatively high level, the structure of the current ISO-NE Capacity Market rules. Under the existing systems, resources with Capacity Supply Obligations (CSO) are entitled to monthly capacity payments because they have cleared their capacity in the Forward Capacity Auction (FCA) or Reconfiguration Auctions[2]. A resource's capacity payment equals the product of its CSO and the Capacity Clearing Price in the applicable FCA or Reconfiguration Auction, subject to two payment reductions.

The first payment reduction is the Peak Energy Rent (PER) deduction which applies to all active generating and import resources with CSOs. PER reduces a resource's capacity payments if the Real Time Locational Marginal Price (LMP) for that resource exceeds the administratively determined strike price for a dual fuel combustion turbine unit regardless of whether that resource is operating in real-time or receiving real time revenues.

The second payment reduction – a penalty – comes into effect for any resource that assumed a Capacity Supply Obligation but failed to be fully available during a Shortage Event.[3] The Shortage Event is defined as a period of thirty or more contiguous minutes in which the system-wide or constrained zone specific price of the Ten-Minute Non-Spinning Reserve (TMNSR) or the Thirty-Minute Operating Reserve (TMOR)

[1] ISO-NE Strategic Planning Initiative White Paper entitled "FCM Performance Initiatives," October 2012 (FCM PI White Paper)
[2] Monthly FCA payments are stipulated in Section III.13.7.2.1.1. of the Market Rule 1
[3] Section III.13.7.2.7.1.2. of Market Rule 1

hits the administratively pre-determined cap for that service, indicating TMNSR or TMOR scarcity on the system[4].

The resource is considered available at its Economic Maximum Limit if:

(a) The resource was on-line with metered output above zero and following ISO dispatch instructions; or
(b) The resource was off-line with zero metered output, but it was available for dispatch and was following ISO's dispatch instructions and was capable of starting at ISO's request within thirty minutes; or
(c) The resource was off-line with zero metered output, but it was available for dispatch and was following ISO's dispatch instructions; was capable of starting within 12 hours and its output was competitively offered into the Energy Market but it was not committed by the ISO and consequently the resource was not available to operate within the 30 minute time period.
(d) The resource was off-line with zero metered output either because of a transmission outage or because it was on an approved maintenance or refueling outage.

In sum, under the current rule,

- Performance is related to the resource's *availability* relative to its CSO and the physical characteristics of the unit, i.e., start times, ramp time, etc. Availability in accordance with the resource's base physical characteristics is rewarded through the FCA payment received in the Forward Capacity Market. In addition, resources are compensated for energy and operating reserves they provide in the energy market and markets for ancillary services
- Non-availability is penalized. Resources that are not available up to their CSO are penalized in proportion to their full deviation between the CSO and their measured availability.
- Any Resource that is off line on planned / scheduled maintenance or refueling, is constrained from delivery by a transmission outage or that has met its obligation to offer its CSO into the Energy Market and was not dispatched by ISO-NE is not considered non-performing and is not penalized.

ISO-NE's Pay for Performance Design

ISO-NE's design of its performance incentives proposal rests on three fundamental assumptions, as stated in ISO-NE documents:

> 1. "A *Scarcity Condition* [formerly a shortage event] would be any 5-minute interval when the real-time reserve clearing price includes the Reserve Constraint Penalty Factor (RCPF) for: - System shortage of Total Operating Reserves, or - System shortage of Total 10-Minute Reserves, or - Zonal shortage of 30-Minute Reserve Requirement for the associated zone"[5]

[4] Section III.13.7.1.1.1 of Market Rule 1. Note that the definition of Shortage Event was changed in November 2013 to include TMOR. Prior to that time it had only included TMNSR.
[5] ISO-New England Performance Incentives Reference Guide, August 7, 2013. Page 1.

2. "*Forward position.* The Forward Capacity Auction determines a resource's base capacity payment, and creates a physical obligation and forward financial position in the capacity market. A resource's forward financial position is a share of the system's energy and reserve requirements during a reserve deficiency event"[6].

3. "*Settlement for deviations.* The performance payment during a reserve deficiency event is based on the deviation between a resource's actual performance and its forward financial position. These deviations are credited or charged at the Performance Payment Rate."[7]

The combination of these assumptions leads to the revised FCM related payment formula for all resources in the ISO-NE Forward Capacity Market (FCM) (Formula (1)):

$$Payment = P_{FCM} \times CSO + PPR \times \sum_{events} Score \quad (1)$$

Where

$Payment$ is the annual payment received by the resource in the FCM mechanism

P_{FCM} is the clearing price in the FCM auction

CSO is the capacity supply obligation of the resource cleared in the FCM auction

PPR is the Performance Pay Rate applied to the $Score$ of the resource in each period of scarcity conditions

The sum in the formula would be taken over all Scarcity Conditions that occurred for that resource during the period.

According to the proposed design, the $Score$ would be measured in MW and calculated for each resource for each scarcity condition. It would be calculated in such a manner that $Score$ values for the so called "over-performing" resources would be positive, for so-called "under-performing" resources – negative and the total sum of all scores during one scarcity condition period would be a negative number proportional to the shortage of MW that caused the scarcity condition. Thus, in accordance to this formula, each scarcity condition would trigger a reallocation of money primarily from "under-performing" resources to "over-performing" resources with the possibility that a small fraction of money collected from "under-performing" resources would be credited to consumers.

The proposed scoring system is based on the following formula (Formula (2)):

$$Score = Actual\ \mathrm{MW} - CSO \times BalancingRatio \quad (2)$$

[6] ISO New England Market Development, Memorandum to NEPOOL Markets Committee "FCM Performance Incentives – Performance Payment Rate", September 4, 2013. Page 1.
[7] Ibid.

Where:

$Actual\ \text{MW}$ - is the capacity of the resource delivering energy to the system plus capacity designated as providing reserves at the time of scarcity. Balancing Ratio is in turn defined as:

$$BalancingRatio = \frac{\text{Load + Operating Reserve Requirements}}{\text{Total CSO cleared in FCM}} \quad (3)$$

Note that the numerator in equation (3) relates to the actual load and operating reserve at the time of the scarcity condition.

Also note that formula (1) applies to all resources, including those that assume a CSO as well as those that do not assume a CSO in the FCM market.

- A resource with a CSO receives payment in the form of $P_{FCM} \times CSO$ and receives additional payments or is subject to charges in the form of $PPR \times \sum_{events} Score$ depending on whether the sum of all their Score values across all periods of scarcity condition is positive or negative.
- A resource without a CSO (i.e., their CSO is zero) receives zero advanced FCM payment but in any period of scarcity condition has either a zero or positive Score and therefore has an opportunity to receive payments but faces no risk of being assessed a charge.

The proposed scoring system expressed in formulas (2)-(3) implements the second of ISO-NE's fundamental assumptions that a "resource's forward financial position is a share of the system's energy and reserve requirements during a reserve deficiency event." The settlement for deviations assumption as expressed in Formula (1) indicates that the settlement for *deviations* is the compensation or charge in the form of the PPR multiplied by "the *deviation* between a resource's actual performance and its forward financial position."

Design Flaws: Two Examples

To understand the ISO-NE Proposal it is helpful to consider the following arithmetic examples.

Example 1. Assume that a large base load unit (e.g., a nuclear unit) with a CSO of 1000 MW is fully operational (Actual MW = 1000 MW) at the time of a scarcity condition that lasts for 1 hour. Let us further assume that Balancing Ratio at the time of scarcity is 50%. According to formula (2), the unit's Score would be equal to:

Score = 1000 MW – 50% x 1000 MW = 500 MW

Given that Score and that PPR is set at $2000/MWh, the unit would receive a performance incentive payment of:

$2000/MWh times 500 MW times 1 hour = $1,000,000.

This additive payment would be made even though the unit has been available at its CSO for which it already received full compensation through the first part of formula (1) (the FCM price). The added payment would be made notwithstanding the fact that the generator would have been compensated for all delivered energy through the energy price, remembering that large base load units typically do not provide operating reserves, only energy and planning reserves.

To fully appreciate the significance of this example, recall that there are 4540 MW of nuclear capacity in New England.[8] In this example, if such a 1 hour scarcity condition occurs under the 50% balancing ratio, the "under-performing" generators would transfer over $4.5 million for a single hour to nuclear generators for performing to their CSOs.

Example 2. Consider now an example of two "under-performing" resources – two combined cycle generators CC1 and CC2, each with 500 MW of CSO. Assume that under the same scarcity conditions shown in Example 1, CC1 was in the Day-Ahead market committed to run at full capacity during the hour of scarcity but becomes unavailable in real time due to a forced outage. CC2 competitively offered 500 MW in the Day-Ahead market but was not scheduled to run during the scarcity hour, because by following the ISO dispatch instruction it was shut down 1 hour prior and therefore was off-line when the scarcity conditions developed and could not be re-started within one hour of scarcity condition. Under the proposed PI both units would have the same Score and would be facing the same penalty charge. With the 50% Balancing Ratio, each unit's Score would be equal to:

$$\text{Score} = 0 \text{ MW} - 50\% * 500 \text{ MW} = -250 \text{ MW}$$

Both units would be subject to the Penalty Payment of $500,000. For CC1, it would receive a penalty assessed on 250MW even though its full 500MWs was not available. On the other hand, CC2 would also be penalized 250MW even though it was available and it operated in full accord with the ISO-NE dispatch instructions.

This example has two important implications. First, CC2 could properly be viewed as subsidizing the payments of CC1. For example, under the current system, only CC1 would be penalized and the penalty for CC1 would be assessed on the basis of its entire CSO, i.e. 500 MW, not 250 MW, whereas CC2 would not be penalized at all. Under the proposed system, CC2 effectively would be made responsible for half of the CC1's penalty. Second, the payments collected from penalized generators would mostly be used to finance the so-called over-performance of generators that were online under the scarcity conditions even to all those generators that would be performing up to their CSO levels and, as shown in Example 1, are already compensated for those deliveries in the real-time market.

To properly appreciate the magnitude of this revenue shift with the proposed PI mechanism, it is important to note that should the scarcity conditions emerge under the 50% balancing ratio, this mechanism would penalize at least 50% of all installed capacity in New England, or 50% of approximately 32,000 MW. The collective Score of this penalized capacity would be 8,000 MW (16,000 MW less 50% of 16,000 MW) and the resulting penalty assessed on this capacity at $2000/MW PPR

[8] Estimated as an average of the summer and winter Seasonal Claimed Capability per CELT.

would amount to at least $16 million dollars. This $16 million or more would be redistributed to on-line generators for what is proposed to be considered "over-performance" when in fact such a payment would be a substantial additional payment for performing according to their CSOs.

Fatal Flaws in the ISO-NE Proposal

The above two simple examples illustrate a number of fatal flaws in the ISO-NE Proposal. The most egregious flaw is that it is based on the assumption that the CSO resource's forward financial position is ***a share*** of the system's energy and reserve requirements during a time of a scarcity condition. This assumption is not logical, is arbitrary and is contrary to the actual requirements of a CSO in the FCM market. This assumption is also not supported by the economics and operations of ISO-NE's markets for energy and ancillary services.

This assumption is illogical and arbitrary because it has no relation to the "physical obligation" of the resource or any other relationship to FCM. Section III.13.6.1.1.1 of Market Rule 1 states that "a Generating Capacity Resource having a Capacity Supply Obligation shall be offered into both The Day-Ahead Energy Market and Real-Time Energy Market at a MW amount equal or greater than its Capacity Supply Obligation whenever the resource is physically available." Thus, the physical responsibility or obligation of the resource is to be available at its entire CSO, not a fraction of it, i.e. a balancing ratio. It is illogical to require the resource to be available at full capacity while considering that its "forward financial position" equals only a fraction of the resource's physical obligation. Moreover, if the forward financial position of the resource were set at a fraction of its CSO as is proposed, it is illogical that the payment (P_{FCM}) should be applied to the entire CSO and not simply to the calculated fraction.

This forward financial position assumption contradicts the economics and operations of the energy and ancillary services markets. Setting the so-called forward financial position in proportion to the balancing ratio would only make sense if resources were expected to be dispatched in proportion to the system-wide load they serve. This happens neither in the energy market, nor in markets for ancillary services. Generators are dispatched primarily in merit order on the basis of their economics and as a result are never dispatched in proportion to the load. If the dispatch cost of the generator is low, it is dispatched at its full capacity, i.e. at the entire CSO. If the dispatch cost of the generator is high, it is not dispatched at all. Market rules in New England (and in all other markets) do not provide for generator outputs to simply be scaled up or down in proportion to load. Similarly, a resource's participation in the market for ancillary services is based on the resource's economics, i.e. on the opportunity costs foregone by that resource in the energy market in order to provide reserves.

In short, the forward financial position is an inappropriate benchmark against which to assess the performance of the resource. Performance should be measured against a benchmark that is solidly tied to physical obligations and operational rules, not against illogical metrics such as BR * CSO. As shown in the examples above, by using this illogical benchmark ISO-NE's PI proposal creates an unjustifiable system of resource compensation, provides few if any incentives for investment in additional capacity and, in the process, would lead to massive redistribution of revenues among generators.

Yet another significant flaw of the proposed design is that the ***magnitude of the redistribution of revenues*** created by formula (1) has no connection to the magnitude of the scarcity problem that triggers that redistribution. This redistribution of revenues is not reflective in any way of the magnitude of the shortage to which it is being applied. The magnitude of the revenue redistribution among so called "over-performing" and "under-performing" generators bears virtually no relationship to the magnitude (or cost) of the scarcity problem that triggers this revenue redistribution.

To demonstrate the significance of this problem consider the following example under the same assumption that the scarcity conditions develop under the 50% balancing ratio and the total installed capacity of 32,000 MW. In this example I assume that the scarcity conditions would result in a 100 MW shortage in operating reserves. I assume that the requirements for energy and operating reserves equal 16,000 MW while actual MW under the PI mechanism are only 15,900 MW. This implies that 16,100 MW (32,000 MW total capacity less 15,900 Actual MW) would be non-performing capacity subject to penalty. Thus, the penalty assessed on the system would be:

Penalty = $2000/MWh x 50% x 16,100 MW x 1h = $16,100,000

Of those, the "over-performing" generators would receive:

Reward = $2000/MWh x (15,900 MW – 50% x 15,900 MW) x 1 h = $15,900,000

According to the ISO-NE's Proposal the difference between the penalty collected from "under-performing" generators and the reward paid to "over-performing" generators (which would equal $200,000) would be refunded to consumers.

If one assumes that the shortage was 10 MW instead of 100 MW, and applies the same calculations, the penalty would be equal to $16,010,000, the reward would be $15,990,000 and refund to consumers would be $20,000.

Indeed, the scarcity could be of 1 kW, 1 MW or 100 MW, the results would be the same: the resources providing energy and operating reserves would collectively receive $16.0 million over and above revenues already received for energy and operating reserves and resources that were not dispatched or operating to provide energy or operating reserves would be penalized by approximately an equivalent amount.

ISO-NE justification of the proposed market design

ISO-NE's FCM PI White Paper outlines three points in support of their performance incentive design.

> "The ISO's proposed pay-for-performance approach adheres to several market design principles that characterize efficient, competitive markets:
>
> - It enables suppliers to earn the missing money revenue stream that an efficient energy market would provide, by delivering energy and reserves during scarcity conditions;

- It provides performance payments and charges contingent upon actual performance irrespective of fault;
- It provides the same incentives to all suppliers, regardless of the resource type. Consistent with a competitive market, it neither favors nor discriminates against any class of resources.[9]"

These statements are not accurate given the ISO-NE's Proposal.

ISO-NE Point # 1. The PI System enables suppliers to earn the missing money revenue stream that an efficient energy market would provide, by delivering energy and reserves during scarcity conditions.

As example 1 above demonstrates, this is not correct because the proposed system is designed to compensate certain resources (e.g. large base load generators) at a level that would likely be over and above their just and reasonable revenues from the FCM and energy market. Although such large units may be subject to penalty payments as well as overage payments, assuming an 80% availability of the base load generator, it has a 4:1 greater chance of receiving a net positive payment than of facing a penalty. As a result these generators would be compensated in excess of what an efficient market would provide.

ISO-NE Point # 2. The PI System provides performance payments and charges contingent upon actual performance irrespective of fault

While in real-time this claim may be correct, the fact is that "actual performance" cannot only be tied to the real-time production but must also be cognizant of the dispatch schedule and physical capability of the system. For example, the ISO-NE Proposal does not allow for the fact that the ISO-NE may be the entity at fault for not having scheduled a specific generator for a specific time period or the ISO-NE may have scheduled a transmission outage that prevents a specific generator capable of responding from actually delivering. The concept that "no-fault is allowed" ignores the realities of system operations that, at the end of the day, are entirely within the purview of ISO-NE, not the entities with CSOs. Generators not scheduled may never be given the chance to produce energy or operating reserves during a period of scarcity conditions but still would be penalized for ISO-NE decisions.

ISO-NE point # 3. The PI System provides the same incentives to all suppliers, regardless of the resource type. Consistent with a competitive market, it neither favors nor discriminates against any class of resources.

This claim is also not correct. Resources of different types effectively receive different incentives. Inflexible but low cost generating units such as nuclear capacity would stand to see a positive revenue outcome. Less flexible higher cost generating units would face the potential for significant penalty charges. Resources vary in terms of their physical characteristics and hence in terms of their ability to be able to provide real-time production.

[9] FCM PI White Paper at p.13

While it is acknowledged that the FCM would continue to allow for bilateral trading, the ISO-NE Proposal is not a market and in and of itself provides no tradable products or services. This fact alone would prevent entities with CSOs from hedging their transactions. Further, the magnitude of payments would be disconnected from the magnitude of the operating reserves problem that triggers payments and penalties. As a result, the proposal violates even the most basic principles of cost causation and cannot be considered just and reasonable.

Impact on New England Consumers

The proposed PI mechanism would be burdensome to New England consumers. Indeed, as shown in the report prepared by the Analysis Group, the implementation of the propose PI mechanism would increase FCM clearing prices in 2018/19 planning period from a no FCM PE scenario of $1.31/kW-month to $3.76/kW-month under the low or moderate gas shortages scenario to as much as $4.49/kW-month under the high gas shortages scenarios[10]. Given an ICR for 2018/19 of 34,500MW, this would result in an annual increase of consumer capacity payment over no FCE PI of over $1 billion per year[11,12]. According to the "Historical Scenario" provided in the Analysis Group's report, these incremental payments do not incentivize any new entry of generation[13]. In the Analysis Group Report "Near-Term Equilibrium Scenario" indicates an increase of between 1,036MW and 1,472MW of Surplus Capacity above ICR[14]. However, the Analysis Group appears to assume that any cost effective reliability improvements would be achieved through an increase of dual fuel capacity in New England[15]. However, based on the Analysis Group's data, in contrast to over a $1 billion in incremental annual capacity payments, I estimate that the annualized costs of additional dual-fuel capability would be between $0.6 million and $119 million annually[16].

New England consumers would see a three-fold increase in capacity costs that would incentivize virtually no incremental capacity.

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[10] Todd Schatzki and Paul Hibbard "Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives," The Analysis Group, September 2013 ("The Analysis Group Report"). Table 4 estimates that under current rules the FCA Clearing Prices in the 2018/19 Commitment Period would be 1.31 $/kW-month and under different gas shortage scenarios examined the FCM PI revisions would result in a FCA Clearing price of between 3.76 to 4.49 $/kW-month. (Page 30)

[11] The Analysis Group Report, page 41, lists the Installed Capacity Requirement (ICR) during the 2018/2019 Commitment Period to be 34,500 MW.

[12] Given a 2018/19 ICR of 34,500MW (footnote 11) and The Analysis Group's Report estimates the increase in the FCA Clearing price of between $2.45/kW-month and $3.18/kW-month (footnote 10). The calculated increase in annual consumer capacity payments would be between $1,014,300,000 to $1,316,520,000 (34,500 MW times $2.45/kW-month and 34,500MW times @3.18/kW-month).

[13] The Analysis Group Report, Table 4, Columns 2, 3 and 4, page 30.

[14] The Analysis Group Report, Table 4, Columns 5, 6 and 7, page 30

[15] The Analysis Group Report, Table 3, and text, page 20.

[16] The Analysis Group Report estimates that the incentives created by FCM PI would cause an increase in dual fuel capacity of between 39 MW and 7,988 MW (Table 4, Row 10, Columns 5, 6 and 7) at an annualized cost no greater than $ 15,000/ MW. (Table 3, Pages 20). Based on these values, the annual cost of implementing these upgrades would be between $585,000 and $119,820,000.

The NEPOOL Proposal

The NEPOOL Proposal focuses on providing increased long-term as well as real-time performance incentives to those generators with a Capacity Supply Obligation – specifically focused on measurement of historic performance during system peak periods – a continuous measure of capacity availability. The NEPOOL Proposal also provides for the modification of the real time calculation of energy prices based on the cost of providing energy and reserves (to an administrative cap) in real-time. In contrast to the ISO-NE Proposal, the NEPOOL Proposal is a modification of the current co-optimized structure of the energy and reserves market rather than a fundamental and flawed restructuring of the capacity markets.

The NEPOOL Proposal effectively and efficiently would achieve the goal of providing strong long-term and real-time performance incentives to generators receiving capacity payments from the FCM. The NEPOOL Proposal would achieve the objective by making only two changes in the tariff.

- The first proposed change (III.2.7A Calculation of Real-Time Reserve Clearing Prices) would modify the Reserve Constraint Penalty Factors (RCPF) for Thirty Minute Operating Reserve (TMOR) from $500 to $1,000 and the Ten Minute Non-Spinning Reserve (TMNSR) from $850 to $1,500. As is discussed below, this change would provide for more efficient market signals and thereby a greater positive incentive to generators to be available during periods of reserve shortages. At the same time it would provide a greater real-time signal to the market of the value of the energy as well as the capacity maintained as operating reserves by increasing the LMP.
- The second would be to eliminate the "Shortage Event" and to substitute, in broad concept, the Equivalent Peak Period Forced Outage Rate (EFORp) mechanism. This change is parallel to the FERC approved structure implemented in PJM and is focused on the measurement of capacity availability during all defined EFORp hours rather than availability only during a Shortage Event. EFORp hours would be the same as the Demand Resource On-Peak Hours or hours ending 1400 through 1700 Monday through Friday (excluding holidays) in June, July and August and hours ending 1800 through 1900 Monday through Friday (Excluding holidays) in December and January. The Availability Score would then be the average availability (availability divided by the Capacity Supply Obligation) for all EFORp hours. The score for the current year would then be compared to the five-year historical average to calculate penalties or charges.

The NEPOOL Proposal separates energy (the first bullet) from capacity (the second bullet) elements of the Capacity Supply Obligation and would provide the information and incentives to both capacity and demand to see and respond to scarcity of Operating Reserves and to be available during periods of the year when peak demands are most likely to occur (EFORp hours).

The NEPOOL Proposal offers a well-conceived and rational structure for achieving what the ISO-NE has indicated as its objective, namely to provide an increased incentive to generators and demand resources to be available during periods of localized and system reserve insufficiency. In addition, the NEPOOL Proposal would provide the economic incentives for resources with CSOs to ensure high levels of availability when resource adequacy is most at risk.

- Replacing the Shortage Event with EFORp provides a strong economic signal to those with CSOs to be consistently available. Further, unlike the ISO-NE, the EFORp proposal provides for a rational handling of planned and unplanned outages. Where the ISO-NE Proposal attempts to reward and penalize all CSOs on a real-time, episodic basis, the NEPOOL Proposal, following the logic of the current tariff, does not penalized resources that are unavailable due to refueling, planned outages, scheduling by ISO-NE and transmission constraints. As a result, the NEPOOL Proposal would create an Availability Score for each CSO that is reflective of its availability given standard operating practice. Further, for a resource to remain in the capacity market pool it could not have an annual score of less than 40% for two of the three preceding years.
- By increasing the Reserve Constraint Penalty Factors for System TMOR from $500 to $1,000/MWh and the System TMNSR from $850 to $1,500/MWh the NEPOOL Proposal would provide incentives to the resources with CSOs, to resources without CSOs and to the demand side of the power system.
    - Resources with a CSO would see an increase in the revenue that they can receive for providing TMOR and TMNSR. This increase represents increased revenue potential for CSOs during periods of reserve shortage and therefore a significant positive real-time performance incentive.[17]
    - This same increase in TMOR and TMNSR would provide an incentive to demand that sees a greater price signal to reduce consumption during periods of reserve shortage.
    - Given the incentives and the structure of aggregators of demand, it is likely that the economic incentive associated with this increase in real-time prices would bring additional, highly flexible demand response products into the market.
- Unlike the ISO-NE Proposal the NEPOOL Proposal focuses on the carrot rather than the stick for a performance incentive and in so doing provides the signal for greater economic efficiency of both the capacity market and the energy market.
    - EFORp would reduce the uncertainty in capacity revenues by the creation and implementation of a logical, consistent, time averaged scoring system that would allow CSO entities – and their funding organizations – to better forecast their expected revenues.
    - The increase in penalty factors would provide improved price signals and with them improved real-time market performance that would reduce the price suppression that is currently caused by out-of merit dispatch.

Conclusion

The conclusion of this report is that while the concept brought forward by ISO-NE may provide for greater incentives for performance on the part of those entities with Capacity Supply Obligations (CSO), it is neither just nor reasonable in the manner in which performance incentives are calculated or payments and penalties allocated. ISO-NE has proposed a structure to achieve its objective that defies economic logic in a number of critical ways; provides payments and imposes penalties in unjustified

[17] It must be noted that the amount finally received by entities with CSOs would be net of PER.

circumstances and explicitly (and apparently intentionally) does not reflect cost causation. Further, the ISO-NE Proposal would levy a high cost burden on New England consumers with little if any demonstrated benefit.

In contrast, the NEPOOL Proposal would provide an evolutionary approach to increased performance incentives based upon the current structure of the FCM and the real-time markets offer primarily positive incentives in markets where most appropriate, and reinforce the economic market signals that are the underpinning of the ISO-NE wholesale electricity market design objective.

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Richard D. Tabors, Ph.D. is an economist and scientist with 35 years of domestic and international experience in energy planning and pricing, international development, and water and wastewater systems planning. He is currently President and Principal of *Across the Charles* an energy, water and wastewater consulting group in Cambridge, Senior Consultant at Greylock McKinnon of Cambridge and an Affiliate of the MIT Energy Initiative. Prior to forming *Across the Charles* Dr. Tabors was Vice President of Charles River Associates.

From 1976 until 2006 Dr. Tabors held a variety of position at Massachusetts Institute of Technology culminating in the title of Senior Research Engineer and Senior Lecturer. These positions involved research development and supervision as well as academic teaching and included being Assistant Director of the power systems engineering laboratory (LEES) and associated director of the Technology and Policy master's program. Prior to MIT Dr. Tabors was Assistant Professor of City and Regional Planning and a member of the teaching faculty of the College of Arts & Sciences at Harvard University. At present he is a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland.

Dr. Tabors was a member of the team at MIT that developed the theory of spot pricing (*Spot Pricing of Electricity* Kluwer Academic, 1989) upon which real-time pricing (RTP) and locational marginal pricing (LMP) of electricity and transmissions services are based. While still at MIT Dr. Tabors and coauthors Michael Caramanis & Roger Bohn formed Tabors Caramanis & Associates (1988) that was sold to Charles River Associates in 2004.

Dr. Tabors provides expert assistance and testimony in regulatory and arbitration cases in the energy sector at the Federal, State and Provincial levels in North America and provides technical assistance in electricity markets and market development worldwide. His strength both in academia and in private practice is in the development and management of effective, client and problem focused teams that bring intellectual originality and rigor to the challenges of energy markets.

EXPERIENCE

2012–Present *President and Principal* Across the Charles, an Energy and Environmental Consulting Group, Cambridge, MA and Senior Consultant, Greylock McKinnon Associates

2004–2012 *Vice President*, Charles River Associates

- Co-director of Energy & Environment practice area.

2004–Present *Visiting Professor of Electrical Engineering*, University of Strathclyde, Glasgow, Scotland

1986–2006 *Senior Lecturer*, Technology and Policy Program, Massachusetts Institute of Technology (MIT)

1988–2004 *Founder and Principal*, Tabors Caramanis & Associates, Inc.

1989–1998 *Lecturer*, Department of Electrical Engineering and Computer Science, MIT

- "Introduction to Power Systems Operations and Planning."

1992–1998 *Senior Research Engineer*, Laboratory for Electromagnetic and Electronic Systems, MIT

1985–1998 *Assistant Director*, Laboratory for Electromagnetic and Electronic Systems, MIT

- Responsible for laboratory administration and research in power systems economics and planning, research on power systems monitoring and control, principal investigator on research program in performance based monitoring and control.

1990–1993 *Principal Research Associate*, MIT

- Co-Faculty "Planning for Water and Sewerage" and "Dealing with the Complete System," MIT Summer Session.

1984–1989 Co-Faculty "Power Systems Planning & Operation: Methodologies for Dealing with an Uncertain Future", MIT Summer Session.

1978-1988 *Lecturer*, Department of Urban Studies and Planning, MIT

1973-1988 *Principal*, Meta Systems

- utilities group in power systems planning, pricing and systems analysis

1985–1987 *Faculty*, Course 11.944, Department of Urban Studies and Planning (co-taught as KSG S115 with P. Rogers) “Energy Sector Planning in Developing Countries.”

1971–1976 *Research Associate and Member*, Center for Population Studies, Harvard University

- Research on resource and environmental planning in developing nations of South Asia and Africa.

1978–1984 *Program Manager*, Utility Systems, MIT Energy Laboratory

- Economic and systems research and development in electric and gas utility systems; including the integration of new generation systems (photovoltaics) into the grid.

1979-1983 *Project Manager and Principal Investigator*, Electric Generation Expansion Analysis System (EGEAS) Project, under contract to EPRI, MIT Energy Laboratory.

1977-1982 *Project Manager and Principal Investigator*, Photovoltaics Project, under contract to U. S. Department of Energy, MIT Energy Lab.

1976-1977 *Economist*, Photovoltaics Project, MIT Energy Laboratory and Lincoln Laboratory.

1976-1977 *Energy Economist*, New England Energy Management Information Systems (NEEMIS), Energy Laboratory, MIT.

1974-1976 *Assistant Professor of City and Regional Planning*, Harvard University.

1973-1976 *Research Fellow*, Environmental Systems Program, Division of Engineering and Applied Physics, Harvard University.

1971–1977 *Co-Faculty*, with Professor R. Revelle, Natural Science 118, & 119, Human Population and Natural Resources, and Population & Environment and in Urban Setting, Harvard University.

1973-1974 *Lecturer on City and Regional Planning*, Graduate School of Design, Harvard University.

1971 *Resident Representative*, Harvard University, East Pakistan (Bangladesh) Land, Water and Power System Study, Dacca, East Pakistan.

1970 *Graduate Administrative and Teaching Assistant* to A. K. Campbell, Dean, Maxwell Graduate School of Citizenship and Public Affairs, Syracuse University.

1969–1970 *Syracuse University Intern*, Economic Division, USAID Pakistan.

- Informal advisor on Regional Economic Planning to the Urban Development Directorate, Planning Department, Government of East Pakistan (Bangladesh).

CONSULTING EXPERIENCE

- For the City of New York provided technical and analytic support in the evaluation of the possible closing of the Indian Point Nuclear Generating Station including analysis of the impact of the Fukushima Nuclear accident (2011)
- Provided technical and economic strategy and regulatory assistance to off-shore wind developer (2009 – Present)
- In cooperation with Merrill Energy, provide expert advice on implementation of legislation to recover capital cost of transmission investment in Peru. (2010)
- Direct and provide consulting advice to the Federal Electricity & Water Authority in the United Arab Emirates on corporate reorganization. (2007-2011)
- Provide expert testimony to major US independent power producer in arbitration with steam host. (2007 – Present)
- Direct and provide expert services and consulting advice to Electricite du Liban on revenue recovery through development of AMI systems. (2006 – Present)
- Direct and provide consulting services to Electricite du Liban on restructuring of distribution services. (2006 – Present)
- Provide expert testimony in multiple contract disputes between bankrupt Independent Power Producer and power marketer. (2004 – 2006)
- Provide expert analytic assistance to Private Equity Fund on purchase of generation assets within the United States (2006- 2007).
- Member, Board of Directors, NeuCo Corporation.
- Direct and provide consulting services to Abu Dhabi Water and Electricity Authority on distribution system performance. (2003–2005)
- Direct and provide expert testimony on the development of the MidWest Independent System Operator. (2002–Present)
- Direct and provide expert testimony on long-term contract market in California. (2002–Present)
- Direct and provide expert testimony in purchase, contracting and regulatory approval of Midwestern transmission system. (2002–2003)

- Direct and provide expert testimony in 9-billion dollar California Electric refund case (2001–Present)
- Direct and provide expert testimony and consulting to major U.S. market and generator in the redesign of the California electricity market. (2002–Present)
- Member of the Blue Ribbon Task Force on design of electricity auctions of the California Power Exchange with Alfred Kahn, Peter Cramton and Robert Porter. (2000–2001)
- Member, Board of Directors of Dynamic Knowledge Corporation, Glasgow, Scotland. (2001–Present)
- Consultant to more than 20 power development companies for evaluation of locational value of new generation and transmission. (1999–Present)
- Consultant to and member of Technology Advisory Board, Excelergy Corporation, development of utility billing and system auction software. (1999–Present)
- Consultant to a Midwest utility for development of transmission congestion pricing structure. (1999–2001)
- Consultant to transmission asset development team of major U.S. corporation. (1999–2000)
- Consultant to and member of advisory board of Altra Energy Systems, electronic trading software and platform development company for electronic trading of electricity. (1998–2001)
- Consultant to major U.S. paper manufacturer for federal regulatory change required to interconnect a new co-generation facility. (1998–2000)
- Consultant to major Midwest utility in the development of an independent transmission company and the required tariffs. (1998–2002)
- Consultant with Enron Capital and Trade Resources on U.S. electricity restructuring with specific assignments in California, New York, Massachusetts and New England. Includes testimony in California “Blue Book” en banc hearings and participation in California Competitive Power Market Working Group. (1994–2001)
- Consultant to the Office of the Attorney General, Commonwealth of Massachusetts for Electric Utility Industry Restructuring. (1995–1998)
- Consultant with Sithe Energy on electricity pricing and electric industry restructuring. (1995–1998)
- Consultant with Independent Power Producers of New York (IPPNY) on restructuring of electric sector in New York. (1995–1998)

- Consultant to the Department of the Attorney General, State of Rhode Island and Providence Plantation for electric utility industry restructuring. (1996–1997)
- Consultant to the New England Competitive Power Coalition providing support for development of a blueprint for restructuring the New England Power Pool. (1995–1997)
- Consultant to ABB/Systems Control on transmission pricing and power systems operations. (1994–1997)
- Consultant to a major western utility for the development of transmission pricing strategies. (1994–1996)
- Development of real-time pricing strategies and rates for Oglethorpe Power Company, Atlanta, GA. (1995–1996)
- Consultant on the background to electric industry restructuring to Central Vermont Public Service. (1995)
- Development of real-time pricing rate response experiments for NYSERDA, EPRI and ESSERCo in ConEd and NYSEG service territories: Response to real-time pricing. (1989–1994)
- Development of marginal, cost-based, transmission system pricing system for the National Grid Company (NGC) of the United Kingdom. (1991–1993)
- Development of real-time rate structure and evaluation of customer impacts for Central Maine Power Company. (1990–1991)
- Development of purchase and transmission strategy for major U.S. independent power producer. (1990)
- Conservation and load management analysis and testimony for Boston Gas Company. (1987–1988)
- Development of Electric Power Systems Consulting Group, Meta Systems Inc. (1985–1988)
- Variable energy cost/spot pricing studies under contract to Integrated Communications Systems of Atlanta. Utilities included Mid-South and Pacific Gas and Electric, Southern California Edison, Central and South West. (1984-1987)
- Metcalf & Eddy Engineering, analysis of economic benefits of cogeneration/district heating for Columbia Point housing, Boston Redevelopment Authority. (1984–1985)
- Value of reliability study for Public Service of New Mexico. (1984)
- With East-West Center, Honolulu, Hawaii, study of electric futures of northeast Asia, Japan, Korea and Taiwan. (1983–1984)

- Independent variable energy cost spot pricing studies for Georgia Power, Florida Power and Light, Florida Power Corp., Tampa Electric and Gulf Power. (1983–1984)
- Petroleum pricing study, Philippines for IBRD. (1983–1984)
- Lignite pricing for electric power generation, Thailand. For IBRD (1982–1983)
- Independent, review of electric power futures for combustion engineering. (1982)
- Consultant, Microwave Associates, Inc., on electric load management and control. (1980-1981)
- Urban energy impact statement for HUD. (1979–1980)
- Consultant, Urban Systems Research and Engineering. Projects included: Analysis of Boston wastewater management plan for C.E.Q.; definition of 'modal' urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model; Interceptor project to evaluate the impact of EPA interceptor grants program or land use patterns in suburban and rural areas of EPA Regions 2, 4, 6; Rural growth project analyzing regional development in non-metropolitan multi-county areas in the United States. (1971–1977)
- Urban systems research and engineering analysis of Boston wastewater management plan for C.E.Q. (1977)
- Bangladesh energy study for Asian Development Bank and UNDP. (1975–1976)
- Urban systems research and engineering, definition of model urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model. (1975–1976)
- Land use and environmental quality modeling and case study analysis of land use impacts on water and air quality. Case studies focused on the Mill River basin in the New Haven SMSA. (1974–1975)
- Member, Technical Advisory Panel for Educational Evaluation in Massachusetts, Office of the Commissioner in Education, Commonwealth of Massachusetts. (1973–1974)
- Lake Chad polder development study of agricultural development with low-lift irrigation pumping in the area immediately surrounding Lake Chad. (1974)
- Urban systems research and engineering, interceptor sewer project to evaluate the impact of EPA interceptor grants program on land use patterns in suburban and rural areas of EPA Regions, 2,4,6. (1974)
- Decision-making and flood plain management in the Connecticut River valley, study for New England River Basin Commission. (1973)

FIELDS OF EXPERTISE

- Energy economics / energy pricing
- Power systems operations and planning
- Asset valuation: Generation, Transmission and Generation
- Water and wastewater management
- Corporate strategic planning and analysis
- Corporate reorganization and management

PROFESSIONAL AFFILIATIONS

- Institute of Electrical and Electronic Engineers
- American Waterworks Association
- International Association of Energy Economists
- Energy Bar Association

PUBLICATIONS

Books, Book Chapters, and Monographs

The Definition of Multifunctional Planning Regions: A Case Study of East Pakistan. A report to the East Pakistan Land, Power and Water Study, Harvard University Center for Population Studies, May 1971.

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Testimony before the Federal Energy Regulatory Commission (ER 10-1138) on behalf of Northwestern Energies, June 2012

Testimony before the Federal Energy Regulatory Commission on behalf of First Energy Service company (ER13-535-000) in opposition to the proposed Minimum Offer Price Rule changes December 2012 and March 2013.

Testimony before the Federal Energy Regulatory Commission on behalf of NEPOOL (ER13-895-000) in opposition to changes in market timing rules related to acquisition of natural gas. (with Seabron Adamson)

Expert Report in support of the Coushatta Tribe of Louisiana v. Richard Meyer and Meyer & Associates before the State Court of Louisiana (Ongoing)

Expert Reports and Testimony before the FERC Enforcement Bureau for multiple clients accused of market manipulation of US organized power markets (Ongoing)

Testimony before the Ohio Public Utility Commission on behalf of First Energy Solutions in opposition to proposed tariff changes by Duke Energy Ohio. April 2013.

FILED BEFORE THE UNITED STATE SUPREME COURT

Led the *Amici* in *Amicus Curiae* of Electrical Engineers, Energy Economists and Physics in Support of the Court in No. 00-568. State of New York, et al v. Federal Energy Regulatory Comm'n, et al and Enron Power Marketing, Inc v Federal Energy Regulatory Comm'n et al May, 2001

Signed as *Amicus* in *Amicus Curiae* of Leading Economists and Educators who have Designed, Studied, Taught and Written about Electricity Markets in support of the Court in No. 11-1486, Electric power Supply Association, et al, v Federal Energy Regulatory Commission, et al. June 2012

Led the *Amicus Curiae* of Electrical Engineers, Scientists and Economists in Support of the Court in *writ of certiorari,* Metropolitan Edison Company and Pennsylvania Electric Company v. Pennsylvania Public Utility Commission, August 2012.

ATTACHMENT N-1g

Summary of NEPOOL Participant Processes
Regarding the ISO-NE and NEPOOL Proposals

NEPOOL Participant Processes Regarding the ISO-NE and NEPOOL Proposals

This Attachment summarizes the NEPOOL Participant Processes employed over more than a year to explore, analyze and discuss among ISO-NE, Market Participants and New England State regulators numerous alternative market changes to improve incentives for capacity resources to be available to ISO-NE when they are most needed. The concerns from the view point of ISO-NE were previewed in part in its strategic plan issued in 2011.[1] ISO-NE then, in October 2012, issued its white paper, entitled "FCM Performance Incentives". From that point, there were 15 Market Committee meetings at which the reasons for and details concerning the the ISO-NE Proposal were reviewed. Market Participants and representative of State regulators provided substantial feedback and proposed and discussed numerous changes and alternatives. As explained below, that process ultimately resulted in an overwhelming rejection of the ISO-NE Proposal and support by more than 80% Vote, with numerous abstentions noted, the alternative NEPOOL Proposal.

I. NEPOOL MARKETS COMMITTEE

A. NEPOOL Markets Committee Discussions

Over more than one year of deliberations, Market Participants and representatives of State regulators raised a host of concerns with the ISO-NE Proposal. In an effort to remedy their concerns with the ISO-NE Proposal, members offered numerous amendments and alternatives to the ISO-NE Proposal. An index of the complete set of materials presented to the Markets Committee is included as *Attachment N-1g.2*.

B. NEPOOL Markets Committee Votes

In the culmination of its process, the Markets Committee voted on the ISO-NE Proposal at its November 13-14, 2013 meeting. The ISO-NE Proposal was presented with a motion made at the request of ISO-NE for the Markets Committee to recommend that the Participants Committee approve it at the upcoming annual NEPOOL meeting. There were 13 Participant-sponsored motions to amend the ISO-NE Proposal, only one of which received broad support.[2]

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[1] *See* ISO-NE's "Strategic Planning – Risk Summary" (June 14, 2011), available at: http://www.iso-ne.com/committees/comm_wkgrps/strategic_planning_discussion/materials/4_spd_risk_summary_may_2011.pdf.)

[2] The motions to amend that as supported by the Markets Committee, offered by Brookfield Energy Marketing ("Brookfield"), would amend Section III.13.7.2.4 such that, if a resource is subject to an ISO-NE-imposed operational limit (defined by Brookfield to include transmission outages, de-rates, voltage issues, and the largest system contingency protection restrictions), the resource would not be penalized for non-delivery of energy or reserves above that ISO-NE imposed restriction. That motion to amend passed with a Markets Committee Vote of a 71.77% in favor. The individual Sector votes were Generation (15.02% in favor, 2.15% opposed, 2 abstentions), Transmission (8.58% in favor, 8.59% opposed), Supplier (17.17% in favor, 0% opposed, 12 abstentions), Alternative Resources (14.17% in favor, 0% opposed), Publicly Owned Entity (2.52% in favor, 14.65% opposed, 5 abstentions), and End User (14.31% in favor, 2.86% opposed, 1 abstention). That amendment was also offered at the Dec. 6,

The remaining 12 motions to amend were not supported by the Markets Committee. The once-amended main motion to recommend Participants Committee support for an amended ISO-NE Proposal was then voted and was overwhelmingly opposed. Similarly, at the request of ISO-NE, the Markets Committee considered and failed to recommend Participants Committee support for the unamended ISO-NE Proposal, with only a hand-full of votes registering support.[3]

II. NEPOOL BUDGET & FINANCE SUBCOMMITTEE

In addition to the Market Rule and related Section I.2.2 definition changes contained in the ISO-NE and NEPOOL Proposals described in this filing, NEPOOL members and state regulators also considered related changes needed to the Financial Assurance Policy. These proposed changes would expand financial assurance requirements to include in each Market Participant's calculation of its financial assurance obligations the obligations associated with the ISO-NE Proposal (and thereby protect against potential defaults that could result from the imposition of penalties for failure to perform associated with the ISO-NE Proposal) (the "FA Changes"). The FA Changes were vetted through the Budget & Finance Subcommittee at two Subcommittee teleconference meetings convened in November.

With one exception, no Subcommittee member attending those meetings expressed concerns that were specific to the Financial Assurance Policy, although several Subcommittee members reserved their rights to object to the FA Changes as part of the larger ISO-NE Proposal. One Subcommittee member from the AR Sector expressed concerns with how the FA Changes might impact state-sponsored energy efficiency programs.

III. NEPOOL PARTICIPANTS COMMITTEE

A. December 6, 2013 Participants Committee Meeting

Subsequent to Markets Committee consideration of the ISO-NE Proposal, the ISO-NE Proposal was considered by the Participants Committee at its December 6, 2013 annual meeting. All of the materials circulated in advance of the meeting can be found on the NEPOOL website at http://nepool.com/NPC2013.php. The final minutes of that meeting have not yet been approved and will be provided to the Commission when they are. The following summary by NEPOOL counsel is to help provide preliminary context, with the expectation that individual NEPOOL Participants will provide their more detailed views directly to the Commission on the Proposals and amendments thereto, as they deem appropriate.

2013 Participants Committee meeting, but was not supported following Participants Committee approval of an alternative motion to amend the ISO-NE Proposal that addressed some but not all of the same issues associated with exempting resources from penalties for production limitations entirely outside of their control(see Section III.B.5 below).

[3] Both the vote on the once-amended main motion and the unamended main motion were determined to have failed by a show of hands. The notice of actions from that Markets Committee meeting is available online at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/actions/2013/mc_actions_13111314.doc.

Since neither the ISO-NE Proposal nor any alternative was recommended by the Markets Committee for Participants Committee support, Participants Committee consideration began with a motion to approve the ISO-NE Proposal. The Participants Committee deliberations were initiated with a report by the Markets Committee Chair on the Markets Committee deliberations, highlighting that ISO-NE had during that process made two changes to its earlier proposal: (1) the inclusion of a "stop loss" provision to accept and annual cap on aggregate performance charges; and (2) a phase in over time of the Performance Payment Rate ("PPR") from the proposed rate of $5,455 per MWh, such that the PPR would initially be se at $ 2,000 per MWh and would climb over time to a rate supported by ISO-NE's theoretical calculation offered to support the PPR. Members then expressed their views and concerns with respect to the ISO-NE Proposal.

Publicly Owned Entity representatives stated objections to the ISO-NE Proposal because they viewed the underlying changes as redundant in light of other efforts then underway in the energy and reserve markets, had the potential to impose substantial additional costs. They expressed a preference to see how other initiatives already approved by NEPOOL and filed with the Commission played out and delivered before committing to broader changes.

Transmission Owner representatives objected to the ISO-NE Proposal noting the fundamental changes to unit configuration that would occur, expressing the view that units should not be penalized if they acted in accordance with ISO dispatch instructions. Further, Transmission representatives added that the ISO-NE Proposal should include an exemption for Resources unable to perform because of transmission limitations which would be entirely outside of their control.

Generator representatives provided a variety of views. Members acknowledged that past operational events and deteriorating Resource performance factors supported the effort to enhance Resource performance incentives. One member expressed concern that, without some change, performance problems could increase, creating greater future problems. He urged support for the ISO-NE Proposal, but with a preference to provide a transmission outage exemption and to eliminate the Peak Energy Rent ("PER") deduction. Several generator representatives objected to the ISO-NE Proposal because it penalized Resources for following ISO dispatch direction, it did not have a transmission outage exemption (which they viewed as illogical given ISO-NE's involvement in scheduling all transmission outages), and it would not support new generation investment in the region.

In support, an End User Participant stated that the ISO-NE Proposal was an appropriate response to the significant inflection point in energy infrastructure, reliability, and market design, and would facilitate the kinds of technologies that were creating this inflection point and would make for a more efficient, lower cost, and more reliable system. Others expressed opposition to the Proposal, objecting because it did not provide an adequate basis upon which Demand Response could participate in the markets. Consumer Advocate End Users objected to the Proposal because it would apply risk to all resources 24/7, was untested, and would create an uncertain but much greater level of risk. They also expressed a strong preference for a more modulated, less comprehensive approach. Other End User representatives objected to the Proposal because it was too risky for the market and, without adequate

exemptions for Resources like energy efficiency and variable resources, could result in the region overpaying for capacity.

An ISO-NE representative expressed appreciation to the stakeholders for their engagement over the past year, noting that, based on stakeholder feedback, ISO-NE had incorporated the phase-in of the PPR and the annual "stop loss", and if the ISO-NE Proposal were to be implemented, ISO-NE would request continued feedback on improving it.

B. Participants Committee Votes on Motions to Amend the ISO-NE and NEPOOL Proposals

The Participants Committee considered a series of proposed amendments to the ISO-NE Proposal and to what ultimately was supported and is now the NEPOOL Proposal. Those amendments are summarized below in the order in which they were offered and considered.

1. Brookfield Amendment #1

The first amendment to the ISO-NE Proposal, offered by the Brookfield representative, was to provide an exemption for Intermittent Power Resources from the penalties associated with the ISO-NE Proposal ("Brookfield Amendment #1"). Some expressed support for Brookfield Amendment #1, indicating that imposing a penalty on intermittent units, which were already subject to a major de-rating of their capacity value, would have no effect on performance by such units, where performance was driven by factors (i.e., the weather) outside of owner/operator control. Others objected to exempting intermittent resources from the penalty provisions without corresponding changes to the eligibility for bonus payments for performing better than their capacity rating. Still others opposed Brookfield Amendment #1 in order to maintain the consistency of capacity product definition for all sellers reflected in the ISO-NE Proposal. ISO-NE indicated that it did not support Brookfield Amendment #1, or any exemptions at all.[4] Brookfield Amendment #1 was voted and was determined by a show of hands to have failed to have achieved sufficient support to amend the ISO-NE Proposal.

2. MMWEC Amendment #1

Massachusetts Municipal Wholesale Electric Company ("MMWEC") Amendment #1 ("MMWEC Amendment #1") was, similar to Brookfield Amendment #1, an amendment to make Intermittent Resources exempt from penalties for failure to perform, but in contrast to Brookfield Amendment #1, would make Intermittent Power Resources ineligible to receive distributions of penalty revenues if they were to perform during a scarcity condition. ISO-NE stated that it could not support MMWEC Amendment #1 for reasons it had stated previously. MMWEC

[4] In explaining its opposition to exemptions, including Brookfield Amendment #1, ISO-NE indicated that its Proposal was developed to create a level playing field so that all Market Participants would be treated the same and evaluated by the same criteria. Reasons for avoiding exemptions included: ensuring that, when offering into an auction, Resources offer based on the same set of performance expectations/requirements and reflecting their true characteristics, without adjustment for the benefits of any special treatment or special exemptions; preventing incentives from undermining incentives; and preventing a shift in risk of the consequences of a failure to perform from a Resource that receives an exemption to everyone else.

Amendment #1 was voted but was not approved, with a 53.33% Vote in favor (Generation – 2.14%; Transmission – 17.17%; Supplier – 1.56%; Alternative Resources – 4.56%; Publicly Owned Entity – 17.17%; and End User – 10.73%). (See "MMWEC #1" Vote on *Attachment N-1g.1*).

3. Brookfield Amendment #2

The Brookfield representative offered a second amendment to exempt from penalties for failure to perform any External Transactions supporting Import Capacity Resources that were not dispatched by ISO-NE due to inaccurate LMP forecast/latency in scheduling protocols ("Brookfield Amendment #2"). ISO-NE stated that it could not support Brookfield Amendment #2 for reasons it had stated previously. Brookfield Amendment #2 was voted and was determined by a show of hands to have failed.

4. NU Amendment #1

A representative of the Northeast Utilities companies ("NU") offered a motion to amend the ISO-NE Proposal so as to exempt a Resource from penalties for failure to perform if that Resource's inability to deliver energy or reserves during a scarcity condition was due to an outage or de-rate of a transmission facility in the New England Control Area ("NU Amendment #1"). A Supplier Sector representative highlighted perceived limitations with NU Amendment #1. A Generator representative supported the proposed transmission outage exemption because it would treat all capacity suppliers similarly. State representatives supported the NU Amendment #1 as but one example of an exemption structured to provide consumer savings without imposing uncontrollable risk on generators. ISO-NE stated that it could not support NU Amendment #1. NU Amendment #1 was voted and was determined by a show of hands to have been approved, with one opposition noted by NextEra Energy Power Marketing ("NextEra").

5. Brookfield Amendment #3

The Brookfield representative offered a third amendment to the once-amended ISO-NE Proposal such that, if a Resource were subject to an ISO-NE-imposed limit, the Resource would not be penalized for non-delivery of energy or reserves above that ISO-NE-imposed limit ("Brookfield Amendment #3"). The Brookfield representative explained that Brookfield Amendment #3, which had previously been recommended by the Markets Committee, was more expansive than NU Amendment #1 because Resources following dispatch instructions for any reason, including to avoid overloading a transmission line, would not be penalized. ISO-NE stated that it could not support Brookfield Amendment #3 for reasons previously stated. Brookfield Amendment #3 was voted but was not approved, with a 56.84% Vote in favor (Generation – 7.36%; Transmission – 3.43%; Supplier – 14.71%; Alternative Resources – 14.17%; Publicly Owned Entity – 0%; and End User – 17.17%). (See "Brookfield #3" Vote on *Attachment N-1g.1*).

6. MMWEC Amendment #2

The MMWEC representative offered a second amendment to amend the once-amended ISO-NE Proposal so as (i) to exempt from the ISO-NE (a) Import Capacity associated with contracts with the New York Power Authority ("NYPA") and (b) Resources unable to

perform or out-of-service due to a planned outage or loss of transmission; and (ii) to revise ISO-NE-proposed Section III.13.7.2.5 to read as follows: "The ISO shall review the Performance Payment Rate in the stakeholder process ~~as needed~~ annually and shall file with the Commission a new Capacity Performance Rate if and as appropriate." ("MMWEC Amendment #2"). Noting planned maintenance outages were a risk better borne by the generator, State representatives indicated their opposition to MMWEC Amendment #2. ISO-NE stated it also opposed MMWEC Amendment #2. MMWEC Amendment #2 was voted and was determined by a show of hands to have failed.

7. NextEra Amendment

The NextEra representative offered an amendment (i) to set the Performance Payment Rate ("PPR") at $5,455 per MWh beginning with FCA9 (i.e., no phase-in of the PPR); (ii) to provide a limited exemption for transmission-related outages; and (iii) to make a change to the monthly "stop loss" provisions ("NextEra Amendment"). The NextEra representative explained that the limited exemption for transmission-related outages included in the NextEra Amendment would replace in its entirety NU Amendment #1 already voted and approved. State representatives reiterated concerns that a PRR set at $5,455 per MWh would result in consumers having to pay more costs than the resulting benefits would justify as well as with NextEra's removal of the NU Amendment #1 language for transmission-related outages. While it supported the $5,455 MWh penalty amount, ISO-NE noted its conclusion that a phase-in and evaluation of the PRR would be appropriate, and therefore did not support the NextEra Amendment. The NextEra Amendment was voted and was determined by a show of hands to have failed.

8. EquiPower Amendment

An amendment offered by EquiPower Resources Management ("EquiPower") would have changed the Proposal so as to permit an existing Resource to submit a Static De-List Bid for up to the megawatt amount that the Market Participant expected may not be physically available due to reductions in ratings as measured by EFORd[5] multiplied by summer Qualified Capacity at 90 degrees ("EquiPower Amendment"). State representatives indicated their opposition to the EquiPower Amendment. ISO-NE opposed the EquiPower Amendment because it believed it appropriate for Resources to submit price and megawatt pairs for each megawatt for which they were qualified. The EquiPower Amendment was voted and was determined by a show of hands to have failed.

9. NU Amendment #2

The NU member offered a second NU amendment that would have modified the Proposal so as to eliminate changes in that Proposal to the current FCM performance rules for passive demand resources ("NU Amendment #2"). ISO-NE stated that it could not support NU Amendment #2. NU Amendment #2 was voted and was determined by a show of hands to have failed.

[5] EFORd is the "Equivalent Forced Outage Rate on Demand".

10. NU Amendment #3

The NU member then offered a third NU amendment that would change the Proposal to reinsert the current Market Rule provisions in the ISO-NE-proposed Section III.13.7.1.1.3 so as to use the resulting hourly MW values for calculating an Existing Generating Resource's Capacity Performance Payment under the ISO-NE Proposal ("NU Amendment #3"). ISO-NE stated that it could not support NU Amendment #3 because it would fundamentally undermine the design it had proposed. NU Amendment #3 was voted and was determined by a show of hands to have failed.

11. PSEG Amendment

An amendment by PSEG Energy Resources & Trade ("PSEG") would have changed the Proposal so as to set the FCA9 Starting Price at $22/kW-month ("PSEG Amendment"). Generator representatives expressed support for the amendment, insisting that there would be no downside to increasing the FCA Starting Price and that the increase would be helpful to the market. State representatives suggested that it was important for stakeholder discussions, which had not addressed this proposal, to take place before consideration of the PSEG Amendment. ISO-NE stated that it did not at that time support the PSEG Amendment, but recognized the need to periodically evaluate the auction starting price and urged that there be process around that issue. ISO-NE noted its plans and expectation for presentation and discussion of a sloped demand curve at the January 2014 Markets Committee meeting, and suggested that, based on feedback to be received, it would make a determination as to how to proceed for FCA9. The PSEG Amendment was voted and was determined by a show of hands to have failed.

12. Dominion Alternative

An amendment by Dominion Energy Marketing ("Dominion Alternative") would have replaced the once-amended ISO-NE Proposal in its entirety with an EFORd pay-for-performance approach and maintained the enhanced Shortage Event penalty mechanism recently accepted by the Commission.[6] ISO-NE stated that it did not view the Dominion Alternative as an improvement, and as a result could not support it. The Dominion Alternative was voted and was determined by a show of hands to have failed.

13. NRG Alternative (i.e., the NEPOOL Proposal)

NRG then offered an amendment which ultimately became the NEPOOL Proposal, to replace the ISO-NE Proposal in its entirety with Market Rule revisions (described in more detail in the NEPOOL transmittal letter, Attachment N-1a) (the "NRG Alternative"). Members supporting the NRG Alternative expressed their view that the NRG Alternative was a major improvement over the ISO-NE Proposal because it was more likely to incent new investment, more appropriately reflected the abilities of existing Resources, and placed stronger incentives in the energy market. Others expressed support for the NRG Alternative as a rational approach, taking measured steps to address evolving regional challenges in the proper market context, and identifying and implementing further incremental changes with the benefit of experience rather

[6] *ISO New England Inc. and New England Power Pool*, 145 FERC ¶ 61,095 (Nov. 1, 2013).

than waiting until June 1, 2018 (the start of the Capacity Commitment Period associated with FCA9) as proposed by ISO-NE. In addition, some members supported the NRG Alternative because the region could minimize the large anticipated increase in capacity prices under the ISO-NE Proposal, while the benefits of other initiatives could be assessed. Others attributed their support to an increased confidence that the changes proposed by the NRG Alternative could be hedged in the marketplace.

A number of members indicated their intention to abstain when voting on the NRG Alternative, noting that, while they found the Alternative preferable to the ISO-NE Proposal, they needed additional time to determine whether they could affirmatively support the Alternative. One member who abstained identified concerns with the Alternative's details, but stressed the importance of sending a signal to the Commission that an alternative to the ISO-NE Proposal was the right choice for the region at that time. Members also spoke in opposition to the NRG Alternative, with one explaining that, while his company was supportive of improving energy pricing, it could not support the NRG Alternative because it would replace the ISO-NE Proposal with something that would not address all the region's identified performance issues.

Although the States did not express a collective opinion on the NRG Alternative, individual state representatives expressed support for the NRG Alternative because it would improve price formation, would result in market rather than administrative response by units, and ultimately was an appropriate and preferable alternative to what they believed to be a deeply flawed ISO-NE Proposal. ISO-NE identified its concerns with the NRG Alternative, noting: (1) the Alternative, relative to what was then in place in the Tariff, would take a step backwards with respect to incenting Resource performance; (2) the Alternative would not resolve the "zombie resource" or "money for nothing" problems so characterized; and (3) ISO-NE had not had an opportunity to fully consider the adjustments to the NRG Alternative presented at the meeting.

The Committee voted and approved the NRG Alternative with a 80.28% Vote in favor (Generation – 14.71%; Transmission – 13.73%; Supplier – 15.45%; Alternative Resources – 3.37%; Publicly Owned Entity – 17.17%; and End User – 15.85%). (See "NEPOOL Proposal" Vote on *Attachment N-1g.1*).[7]

14. NRG Amendment #2

NRG then offered a second amendment to amend further the NRG Alternative to eliminate the FCM PER deduction ("NRG Amendment #2"). An End User representative supporting NRG Amendment #2 suggested the PER deduction be eliminated because, as then structured, it did not serve as an effective hedge for load, was arbitrary, had unwanted effects on Demand Response ("DR") and other Resources not dispatched within those hours, and did not provide a hedge against scarcity pricing. An AR representative echoed those sentiments, indicated his view that the energy market was already sufficiently mitigated, and indicated that he would support the elimination of the PER deduction. A Transmission member expressed opposition to eliminating PER, indicating that it was a hedge for load, as well as a protection

[7] The votes on this NRG motion to amend the ISO-NE Proposal, and on the amended proposal at the end of the amendment voting process was identical. Accordingly, the results in both instances are referred on the attached tabulation as the NEPOOL Proposal.

against the exercise of market power. The NESCOE representative indicated support for the view that the PER deduction could result in consumer savings but also support for reconsidering the mechanism. He went on to indicate that the States would, however, collectively oppose the elimination of the PER deduction and NRG Amendment #2.

ISO-NE indicated that, in the context of its Proposal, it would support discussion about PER and how it worked in conjunction with the ISO-NE Proposal, but given that its Proposal had been replaced by NRG Amendment #1, ISO-NE could not support NRG Amendment #2.

The Committee voted and failed to approve NRG Amendment #2 with a 44.01% Vote in favor (Generation – 17.17%; Transmission – 0%; Supplier – 17.17%; Alternative Resources – 6.55%; Publicly Owned Entity – 0%; and End User – 3.12%). (See "NRG #2" Vote on *Attachment N-1g.1*).

15. GDF SUEZ Amendment

An amendment by GDF SUEZ Energy Marketing North America ("GDF SUEZ") was offered so as to modify the PER deduction to avoid potential outcomes where Resources would effectively operate a loss when called on by ISO-NE to provide generation, operating reserves or regulation services in Real-Time ("GDF SUEZ Amendment"). ISO-NE stated that it did not support the GDF SUEZ Amendment. The GDF SUEZ Amendment was voted and was determined by a show of hands to have failed by approximately the same vote as that taken on NRG Amendment #2.

16. NRG Amendment #3

The NRG representative offered a third amendment to further amend the NRG Alternative so as to revise the current Market Rules: (i) to permit offer prices for existing Resources (de-list bids) based on 'long-run average costs' rather than 'net risk-adjusted going-forward costs'; (ii) to establish the Dynamic De-List Bid threshold at 80% of the Offer Review Trigger Price of a combustion turbine; and (iii) to enable Existing Resources with IMM-approved offers above the Dynamic-List Bid threshold to participate in the auction at prices below the IMM-approved price ("NRG Amendment #3"). A Supplier representative expressed support for NRG Amendment #3, noting that it would close a gap in the current market design caused by discrepancies in how Resources were required or prohibited from bidding at their long run average cost. State, Publicly Owned Entity, End User, and ISO-NE representatives expressed opposition to NRG Amendment #3. NRG Amendment #3 was voted and determined by a show of hands to have failed, with support coming generally from generators and some suppliers, and opposition or abstentions by others.

C. Participants Committee Votes on the NEPOOL and ISO-NE Proposals

1. Vote on NEPOOL Proposal

After completing consideration of each of the proposed amendments, the Participants Committee then considered and approved the twice-amended main motion (i.e., the NRG Alternative) with a 80.28% Vote in favor (Generation – 14.71%; Transmission – 13.73%;

Supplier – 15.45%; Alternative Resources – 3.37%; Publicly Owned Entity – 17.17%; and End User – 15.85%). (See "NEPOOL Proposal" Vote on *Attachment N-1g.1*).[8]

2. Vote on ISO-NE Proposal

Following NEPOOL approval of the NEPOOL Proposal (i.e. the NRG Alternative), at the request of ISO-NE, the Participants Committee considered the unamended ISO-NE Proposal, as offered and seconded at the beginning of the discussion.[9] The Committee then voted and failed to approve the unamended ISO-NE Proposal with a 10.28% Vote in favor (Generation – 2.86%; Transmission – 2.86%; Supplier – 1.29%; Alternative Resources – 2.66%; Publicly Owned Entity – 0%; and End User – 0.61%). (See "ISO-NE Proposal" Vote on *Attachment N-1g.1*).

D. Vote on ISO-NE Proposal-Related Financial Assurance Policy Changes

Following action on the NEPOOL and ISO-NE Proposals, the Participants Committee considered the FA Changes described in Section II above. The Participants Committee supported the FA Changes subject to two understandings. The first understanding was that support for the FA Changes (i) was conditioned on Commission approval, and ISO-NE implementation of, the ISO-NE Proposal without change that would impact the financial assurance requirements, and (ii) was without prejudice to any position taken or to be taken by a Participant on the ISO-NE Proposal. The second expressed understanding was that, should the Commission require changes to the underlying ISO-NE Proposal that impact the financial assurance requirements, the FA Changes and any proposed revisions thereto would be re-presented to NEPOOL for subsequent consideration in the Participant Processes.

[8] Passage of a motion to change a Market Rule requires a Participant Vote equal to or greater than 60% of the Participants Committee's aggregate Sector Voting Shares. As already indicated, an alternative Market Rule change that is approved by a vote of at least 60% of the Participants Committee. will enjoy "jump ball" status (i.e. the ability contractually to be considered by the Commission on equal legal footing with an ISO-proposed Market Rule change). In light of the support for the NEPOOL Proposal (i.e., the NRG Alternative), a "jump ball" has been created here.

[9] Pursuant to Section 11.1.3 of the Participants Agreement, ISO-NE is entitled to have a vote on its proposal if its proposal is modified in a way that it does not support, with only those changes it does find acceptable, even if an alternative proposal has already passed.

ROLL-CALL VOTES TAKEN ON ISO-NE AND NEPOOL PROPOSALS AT DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

TOTAL

SECTOR	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
GENERATION	2.15	7.36	14.71	17.17	2.86
TRANSMISSION	17.17	3.43	13.73	0.000	2.86
SUPPLIER	1.56	14.71	15.45	17.17	1.29
AR	4.56	14.17	3.37	6.55	2.66
PUBLICLY OWNED ENTITY	17.17	0.00	17.17	0.000	0.000
END USER	10.73	17.17	15.85	3.12	0.61
% IN FAVOR	53.33	56.84	80.28	44.00	10.28

GENERATION

Participant Name	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
Dominion Energy Marketing, Inc.	A	F	F	F	O
Entergy Nuclear Power Marketing LLC	A	A	A	F	O
EquiPower Resources Management, LLC	O	O	A	F	O
Essential Power, LLC	A	O	F	F	O
GDF SUEZ Energy Marketing North America	O	O	O	F	F
Generation Group Member	F	F	F	F	0.5
Millennium Power Partners	O	A	A	F	A
NextEra Energy Resources, LLC	O	O	A	F	O
NRG Power Marketing, LLC	O	A	F	F	O
TransCanada Power Marketing Ltd.	O	A	F		
Verso Maine Energy LLC	O	F	F	F	O
IN FAVOR (F)	1	3	6	10	1.5
OPPOSED (O)	7	4	1	0	7.5
TOTAL VOTES	8	7	7	10	9
ABSTENTIONS (A)	3	4	4	0	1

TRANSMISSION

Participant Name	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
Bangor Hydro-Electric Co.	F	A	F	A	O
Central Maine Power Co.	F	O	A	O	O
New England Power Co.	F	O	O	O	F
The United Illuminating Co.	F	F	F	O	O
NU /NSTAR	F	O	F	O	O
Vermont Electric Power Co.	A	O	F	O	O
IN FAVOR (F)	5	1	4	0	1
OPPOSED (O)	0	4	1	5	5
TOTAL VOTES	5	5	5	5	6
ABSTENTIONS (A)	1	1	1	1	0

ALTERNATIVE RESOURCES

Participant Name	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
Renewable Generation					
First Wind Energy Marketing	O	F	O	F	F
Small RG Group Member	A	F	F	F	O
Distributed Generation					
Conservation Services Group	A	F	A	O	O
Small DG Group Member	A	F	A	O	O
Load Response					
EnerNOC, Inc.	O	A	O	F	O
Vermont Energy Investment Corp.	A	F	A	O	O
Small LR Group Member	F	F	A	O	A
LR Provisional Group Member	F	F	F	F	O
IN FAVOR (F)	1	6	1	3	1
OPPOSED (O)	2	0	2	4	5
TOTAL VOTES	3	6	3	7	6
ABSTENTIONS (A)	4	1	4	0	1

ROLL-CALL VOTES TAKEN ON ISO-NE AND NEPOOL PROPOSALS AT DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

SUPPLIER

Participant Name	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
BP Energy Co.	A	A	A	F	A
Brookfield Energy Marketing /CSC	S	S	S	S	S
Brookfield Energy Marketing	F	F	F	F	A
Cross-Sound Cable	A	F	F	F	O
Calpine Energy Services	O	O	F	F	O
Competitive Energy Services, LLC	A	F	F	F	O
Consolidated Edison Energy, Inc.	A	A	F	F	O
Dynegy Marketing and Trade, LLC	O	A	F	F	O
Energy America, LLC	A	A	A	A	A
Exelon Generation Company	O	F	A	F	O
Galt Power, Inc.	A	A	A	A	A
Granite Ridge/Merrill Lynch Commodities	O	A	F	F	O
H.Q. Energy Services (U.S.) Inc.	O	F	O	F	F
Hess	A	A	A	A	A
Integrys Energy Services, Inc.	A	A	A	A	A
Kimberly-Clark Corporation	A	A	A	A	O
Linde Energy Services, Inc.	A	A	A	A	O
LIPA	A	F	F	A	O
PPL EnergyPlus, LLC	O	A	A	F	O
PSEG Energy Resources & Trade LLC	O	F	F	F	O
Vitol Inc.	A	A	F	F	O
IN FAVOR (F)	0.7	6	9	12	1
OPPOSED (O)	7	1	1	0	12.3
TOTAL VOTES	7.7	7	10	12	13.3
ABSTENTIONS (A)	11.3	12	9	7	5.7

PUBLICLY OWNED ENTITY

Participant Name	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
Ashburnham Municipal Light Plant	F	O	A	O	O
Boylston Municipal Light Dept.	F	O	A	O	O
Braintree Electric Light Department	F	O	F	O	O
Chicopee Municipal Lighting Plant	F	O	A	O	O
Concord Municipal Light Plant	F	O	F	O	O
CT Municipal Electric Energy Coop.	F	O	F	O	O
Groton Electric Light Dept.,	F	O	A	O	O
Hingham Municipal Lighting Plant	F	O	F	O	O
Holden Municipal Light Dept.	F	O	A	O	O
Holyoke Gas & Electric Dept.	F	O	A	O	O
Hudson Light and Power Dept.	F	O	A	O	O
Hull Municipal Lighting Plant	F	O	A	O	O
Ipswich Municipal Light Dept.	F	O	A	O	O
Littleton (MA) Electric Light Dept.	F	O	F	O	O
Littleton (NH) Water & Light Dept.	F	A	F	O	O
Mansfield Municipal Electric Dept.	F	O	A	O	O
Marblehead Municipal Light Dept.	F	O	A	O	O
Mass. Municipal Wholesale Elec. Co.	F	O	A	O	O
Middleborough Gas and Electric	F	O	A	O	O
Middleton Municipal Electric Dept.	F	O	A	O	O
New Hampshire Electric Coop.	F	O	F	O	O
Paxton Municipal Light Dept.	F	O	A	O	O
Peabody Municipal Light Plant	F	O	A	O	O
Princeton Municipal Light Dept.	F	O	A	O	O
Rowley Municipal Lighting Plant	F	O	A	O	O
Russell Municipal Light Department	F	O	A	O	O
Shrewsbury's Electric & Cable Ops.	F	O	A	O	O
South Hadley Electric Light Dept.	F	O	A	O	O
Sterling Municipal Electric Light	F	O	A	O	O
Taunton Municipal Lighting Plant	F	O	F	O	O
Templeton Municipal Lighting Plant	F	O	A	O	O
Vermont Electric Cooperative	F	O	F	A	O
VT Public. Power Supply Authority	F	O	F	A	O
Wakefield Municipal Gas and Light	F	O	A	O	O
Wallingford, Town of	F	O	F	O	O
Wellesley Municipal Light Plant	F	O	F	O	O
W. Boylston Mun. Lighting Plant	F	O	A	O	O
Westfield Gas & Electric Light Dept.	F	O	A	O	O
IN FAVOR (F)	38	0	12	0	0
OPPOSED (O)	0	36	0	37	38
TOTAL VOTES	38	36	12	37	38
ABSTENTIONS (A)	0	2	26	1	0

ROLL-CALL VOTES TAKEN ON ISO-NE AND NEPOOL PROPOSALS AT DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING

END USER

Participant Name	MMWEC #1	Brookfield #2	NEPOOL Proposal	NRG #2	ISO-NE Proposal
Cianbro Companies	A	F	F	A	O
Connecticut Office of Consumer Counsel	F	A	F	O	O
Conservation Law Foundation	O	F	O	O	F
Corinth Wood Pellets, LLC	A	F	F	A	O
Dragon Products Company	A	F	F	A	O
Elektrisola, Inc.	A	F	F	A	O
Environment Northeast	F	F	A	A	O
Fairchild Semiconductor Corporation	A	F	F	A	O
Food City, Inc.	A	F	F	A	O
Hardwood Products Company	A	F	F	A	O
Harvard Dedicated Energy Limited	A	F	F	O	O
High Liner Foods (USA) Inc.	F	F	F	A	O
Industrial Energy Consumer Group	F	F	F	F	O
LaBree's Inc.	A	F	F	A	O
Maine Public Advocate Office	A	F	F	A	O
Maine Skiing, Inc.	F	F	F	F	O
Marden's Inc.	A	F	F	A	O
Mass. Attorney General's Office	O	F	F	O	O
MoArk, LLC	A	F	F	A	O
NH Office of Consumer Advocate	A	F	A	O	O
PalletOne of Maine	A	F	F	A	O
PowerOptions, Inc.	A	F	F	O	O
Praxair, Inc.	A	A	A	A	O
St. Anselm College	A	F	F	A	O
Shipyard Brewing Co., LLC	A	F	F	A	O
The Energy Consortium	A	F	F	O	O
Union of Concerned Scientists	O	F	O	O	A
Utility Services Inc.	A	A	A	O	A
Westerly Hospital, The	A	F	F	A	O
Z-TECH, LLC	A	F	F	A	O
IN FAVOR (F)	5	27	24	2	1
OPPOSED (O)	3	--	2	9	27
TOTAL VOTES	8	27	26	11	28
ABSTENTIONS (A)	22	3	4	19	2

NEPOOL Markets Committee Materials
Related to the ISO-NE and NEPOOL Proposals

Materials provided to the Markets Committee during the development of the ISO-NE and NEPOOL Proposals are posted in reverse chronological order on the ISO-NE website at http://www.iso-ne.com/key_projects/fcm_perf_incentives/mc_mtrls/ as follows:

Date	Document Title / Description	Internet Location
Nov 15, 2013	NU MR 1 Redlined Pages #3 Transmission Exemption 11-14-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14c_nu_mr_1_redlined_pages_3_transmission_exemption_11_14_13.doc
Nov 15, 2013	Brookfield Amendment #3 MR 1 Redlined Page 11-06-13 Revision 3	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14a3_brookfield_amendment_3_mr_1_redlined_page_11_06_13_r3.doc
Nov 12, 2013	NU Presentation #1 11-14-13 *Restore Prior Performance Rules for Passive Demand Resources - By David Errichetti*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14c_nu_presentation_1_passive_dr_11_14_13.ppt
Nov 07, 2013	NU MR 1 Redlined Pages #1 Passive DR 11-07-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14c_nu_mr_1_redlined_pages_1_passive_dr_11_07_13.doc
Nov 07, 2013	NU Presentation #2 10-29-13 *Reinstate FCM Provisions for Existing Generation - By David Errichetti*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14c_nu_presentation_2_existing_generation_10_29_13.ppt
Nov 07, 2013	NU MR 1 Redlined Pages #2 Existing Generation 11-07-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14c_nu_mr_1_redlined_pages_2_existing_generation_11_07_13.doc
Nov 06, 2013	GDF SUEZ Alternative MR 1 Redlined Pages 10-22-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14f_gdf_suez_alternative_mr_1_redlined_pages_10_22_13_r1.doc
Nov 06, 2013	ISO MR 1 Section 1 Redlined Effective 2018 11-06-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_iso_mr_1_section_1_redlined_effective_2018_11_06_13.doc

Date	Document Title / Description	Internet Location
Nov 06, 2013	Dominion Presentation 11-14-13 *Alternative to ISO-NE's Performance Incentives - By Ronald Hart*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14g_dominion_presentation_11_14_13.ppt
Nov 06, 2013	EquiPower Presentation and MR 1 Redlined Page 11-05-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14e_equipower_presentation_mr_1_redlined_page_11_05_13.ppt
Nov 06, 2013	ISO MR 1 Appendix A Redlined Effective 2018 11-06-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_iso_mr_1_app_a_redlined_effective_2018_11_06_13.doc
Nov 06, 2013	Dominion MR 1 Redlined Pages 11-14-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14g_dominion_mr_1_redlined_pages_11_14_13.pdf
Nov 06, 2013	MMWEC FCM PI Intermittent Resources Proposal 10-18-13 *Revisions to the FCM Performance Incentives to eliminate the provisions of FCMPI from applying to resources classified as Intermittent Resources - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14b_mmwec_fcm_pi_intermittent_resources_proposal_10_18_13.doc
Nov 06, 2013	ISO Tariff Section I.2.2 Redlined Effective 2014 11-06-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_iso_tariff_section_i_2_2_redlined_effective_2014_11_06_13.doc
Nov 06, 2013	MMWEC Presentation 10-29-13 Revision 1 *MMWEC modifications to FCMPI - By Gary Will PPT*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14b_mmwec_presentation_10_29_13_r1.ppt
Nov 06, 2013	ISO MR 1 Section 13 Redlined Effective 2018 11-06-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_iso_mr_1_section_13_redlined_effective_2018_11_06_13.doc
Nov 06, 2013	Brookfield Amendment #2 MR 1 Redlined Page 11-06-13 *Performance Exemption for Capacity Import Resources offered under the ex post LMP*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14a2_brookfield_amendment_2_mr_1_redlined_page_11_06_13.doc

Date	Document Title / Description	Internet Location
Nov 06, 2013	GDF SUEZ MR 1 Redlined Pages 10-02-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14f_gdf_suez_mr_1_redlined_pages_10_02_13.doc
Nov 06, 2013	Motion	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_motion.doc
Nov 06, 2013	MMWEC FCM PI Planned Outage Proposal 10-17-13 *Revisions to the FCM Performance Incentives (FCMPI) to eliminate Non-performance penalties for the loss of generation due to Planned Outages - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14b_mmwec_fcm_pi_planned_outage_proposal_10_17_13.doc
Nov 06, 2013	MMWEC FCM PI Transmission Outage Proposal 10-17-13 *Revisions to the FCM Performance Incentives (FCMPI) to eliminate Non-performance penalties for the loss of generation due to Transmission Outages - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14b_mmwec_fcm_pi_transmission_outage_proposal_10_17_13.doc
Nov 06, 2013	NextEra MR 1 Redlined 10-24-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14d_nextera_mr_1_redlined_10_24_13_r1.doc
Nov 06, 2013	NextEra Presentation 10-29-13 *Proposal for Performance Incentives - By Michelle Gardner*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14d_nextera_presentation_10_29_13.ppt
Nov 06, 2013	GDF SUEZ Memo October 29, 2013 *Correction - Alternative Changes to Modify the Peak Energy Rent Mechanism - From Tom Kaslow*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14f_gdf_suez_memo_10_29_13.pd
Nov 06, 2013	NRG Presentation 10-08-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14h_nrg_presentation_10_08_13.ppt

Date	Document Title / Description	Internet Location
Nov 06, 2013	ISO Tariff Section I.2.2 Redlined Effective 2018 11-06-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_iso_tariff_section_i_2_2_redlined_effective_2018_11_06_13.doc
Nov 06, 2013	ISO MR 1 Section 13 Redlined Effective 2014 11-06-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14_iso_mr_1_section_13_redlined_effective_2014_11_06_13.doc
Nov 06, 2013	MMWEC FCM PI NYPA Proposal 10-18-13 *Revisions to the FCM Performance Incentives to eliminate the provisions of FCMPI from applying to the Import Capacity Resources associated with the NYPA contracts - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14b_mmwec_fcm_pi_nypa_proposal_10_18_13.doc
Nov 06, 2013	NRG MR 1 Redlined 10-03-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14h_nrg_mr_1_redlined_10_03_13_r1.doc
Nov 06, 2013	MMWEC MR 1 Redlined Pages 10-18-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/nov13142013/a14b_mmwec_mr_1_redlined_pages_10_18_13_r1.doc
Oct 30, 2013	Dominion Presentation 10-29-13 *Addressing ISO-NE's Performance Incentives - By Ronald Hart*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b6_dominion_presentation_10_29_13.ppt
Oct 28, 2013	NU Presentation #1 10-29-13 Revision 1 *Restore Prior Performance Rules for Passive Demand Resources - By Calvin Bowie*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b8_nu_presentation_1_passive_dr_10_29_13_r1.ppt
Oct 28, 2013	NU MR 1 Redlined Pages #2 Existing Generation 10-28-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b8_nu_mr_1_redlined_pages_2_existing_generation_10_28_13.doc
Oct 28, 2013	NU MR 1 Redlined Pages #1 Passive DR 10-28-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b8_nu_mr_1_redlined_pages_1_passive_dr_10_28_13.doc

Date	Document Title / Description	Internet Location
Oct 25, 2013	NU Presentation #2 10-29-13 *Reinstate FCM Provisions for Existing Generation - By Calvin Bowie*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b8_nu_presentation_2_existing_generation_10_29_13.ppt
Oct 25, 2013	NRG MR 1 Redlined 10-03-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b7_nrg_mr_1_redlined_10_03_13_r1.doc
Oct 25, 2013	FCM PI - Stakeholder Amendment Listing 10-25-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b7_nrg_mr_1_redlined_10_03_13_r1.doc
Oct 24, 2013	NextEra MR 1 Redlined 10-24-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b5_nextera_mr_1_redlined_10_24_13_r1.doc
Oct 24, 2013	Analysis Group Presentation 10-23-13 *FCM Impact Assessment - Additional Results - By Paul Hibbard and Todd Schatzki*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2a_analysis_group_presentation_10_23_13.ppt
Oct 24, 2013	NextEra Presentation 10-29-13 *Proposal for Performance Incentives - By Michelle Gardner*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b5_nextera_presentation_10_29_13.ppt
Oct 23, 2013	EquiPower Presentation 09-24-13 *FCM PI – EquiPower Proposal for Administrative Delist – By William Fowler*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b3_equipower_presentation_09_24_13.ppt
Oct 23, 2013	GDF SUEZ Memo October 29, 2013 *Correction – Alternative Changes to Modify the Peak Energy Rent Mechanism – From Tom Kaslow*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b4_gdf_suez_memo_10_29_13.pdf
Oct 23, 2013	MR 1 Redlined Effective 2014 10-23-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2a_mr_1_redlined_effective_2014_10_23_13.docx
Oct 23, 2013	MMWEC MR 1 Redlined Pages 10-18-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b1_mmwec_mr_1_redlined_pages_10_18_13_r1.doc

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Oct 23, 2013	Dominion MR 1 Redlined Pages 10-22-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b6_dominion_mr_1_redlined_pages_10_22_13.doc
Oct 23, 2013	MR 1 Redlined Effective 2018 10-23-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2a_mr_1_redlined_effective_2018_10_23_13.docx
Oct 23, 2013	Brookfield MR 1 Redlined Pages 10-07-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b2_brookfield_mr_1_redlined_pages_10_07_13.doc
Oct 23, 2013	MC Chair/Vice-Chair Memo October 17, 2013 *FCM PI Proposal - Stakeholder Schedule - From Allison DiGrande and Tom Kaslow*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/fcm_pi_chair_vice_chair_memo_extra_october_meeting_10_17_13.pdf
Oct 23, 2013	MMWEC Presentation 10-29-13 Revision 1 *MMWEC modifications to FCMPI - By Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b1_mmwec_presentation_10_29_13_r1.ppt
Oct 23, 2013	MMWEC FCM PI Intermittent Resources Proposal 10-18-13 *Revisions to the FCM Performance Incentives to eliminate the provisions of FCMPI from applying to resources classified as Intermittent Resources - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b1_mmwec_fcm_pi_intermittent_resources_proposal_10_18_13.doc
Oct 23, 2013	GDF SUEZ MR 1 Redlined Pages 10-02-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b4_gdf_suez_mr_1_redlined_pages_10_02_13.doc
Oct 23, 2013	IMM Presentation 10-29-13 *FCM PI Mitigation Design Tariff - By Parviz Alivand*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2a_imm_presentation_10_29_13.pdf
Oct 23, 2013	NRG Presentation 10-08-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b7_nrg_presentation_10_08_13.ppt

Date	Document Title / Description	Internet Location
Oct 23, 2013	GDF SUEZ Alternative MR 1 Redlined Pages 10-22-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b4_gdf_suez_alternative_mr_1_redlined_pages_10_22_13.doc
Oct 23, 2013	Brookfield Presentation 10-08-13 *Proposed modifications to ISO's proposed Pay-For-Performance FCM construct - By Aleksandar Mitreski*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b2_brookfield_presentation_10_08_13.ppt
Oct 21, 2013	MMWEC FCM PI Planned Outage Proposal 10-17-13 *Revisions to the FCM Performance Incentives (FCMPI) to eliminate Non-performance penalties for the loss of generation due to Planned Outages - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b1_mmwec_fcm_pi_planned_outage_proposal_10_17_13.doc
Oct 21, 2013	MMWEC FCM PI Transmission Outage Proposal 10-17-13 *Revisions to the FCM Performance Incentives (FCMPI) to eliminate Non-performance penalties for the loss of generation due to Transmission Outages - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b1_mmwec_fcm_pi_transmission_outage_proposal_10_17_13.doc
Oct 21, 2013	MMWEC FCM PI NYPA Proposal 10-18-13 *Revisions to the FCM Performance Incentives to eliminate the provisions of FCMPI from applying to the Import Capacity Resources associated with the NYPA contracts - From Gary Will*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct292013/a2b1_mmwec_fcm_pi_nypa_proposal_10_18_13.doc
Oct 09, 2013	CT PURA Premium Capacity Plus Proposal 09-17-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c3_ct_pura_premium_capacity_plus_proposal_09_17_13.pdf
Oct 09, 2013	NextEra Presentation 10-08-13 Revision 1 *Forward Capacity Market Revised Stop Loss and PPR - By Joel Newton*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c4_nextera_presentation_10_08_13_r1.ppt

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Oct 09, 2013	EquiPower Presentation 09-24-13 *FCM PI - EquiPower Proposal for Administrative Delist - By William Fowler*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c6_equipower_presentation_09_24_13.ppt
Oct 07, 2013	ISO FCM PI Reference Guide 10-08-13 Revision 1	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03a_iso_fcm_pi_reference_guide_10_08_13_r1.doc
Oct 07, 2013	GDF SUEZ Memo October 8, 2013 *Alternative Changes to Modify the Peak Energy Rent Mechanism - From Tom Kaslow*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c5_gdf_suez_memo_10_08_13.pdf
Oct 07, 2013	GDF SUEZ Alternative MR 1 Redlined Pages 10-08-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c5_gdf_suez_alternative_mr_1_redlined_pages_10_08_13.doc
Oct 07, 2013	IMM Presentation 10-08-13 Revision 1 *FCM PI Mitigation Design Tariff - By Parviz Alivand*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03b_imm_presentation_10_08_13_r1.pdf
Oct 04, 2013	Dominion MR 1 Redlined 10-04-13 PDF	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c2_dominion_mr_1_redlined_10_04_13.pdf
Oct 04, 2013	NRG Presentation 10-08-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c1_nrg_presentation_10_08_13.ppt
Oct 04, 2013	NRG MR 1 Redlined 10-03-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c1_nrg_mr_1_redlined_10_03_13.doc
Oct 03, 2013	MR 1 Redlined 10-02-13 *FCM PI Mitigation Rules*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03b_mr_1_redlined_mitigation_10_02_13.doc
Oct 02, 2013	MR 1 Redlined 10-02-13 *FCM PI Rules*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03a_mr_1_redlined_10_02_13.doc

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Oct 02, 2013	GDF SUEZ MR 1 Redlined Pages 10-02-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03c5_gdf_suez_mr_1_redlined_pages_10_02_13.doc
Oct 02, 2013	ISO Memo October 2, 2013 *FCM Pay for Performance - Revised Elements*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03a_iso_memo_10_02_13.pdf
Oct 02, 2013	ISO FCM PI Tariff Changes Guide 10-02-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/oct892013/a03a_fcm_pi_tariff_changes_guide_10_02_13.doc
Sep 23, 2013	EquiPower Presentation 09-24-13 *FCM PI - EquiPower Proposal for Administrative Delist - By William Fowler*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep242013/a4a2_equipower_presentation_09_24_13.ppt
Sep 23, 2013	Brookfield Presentation 09-24-13 *Proposed modifications to ISO's proposed Pay-For-Performance FCM construct - By Aleksandar Mitreski*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep242013/a4a3_brookfield_presentation_09_24_13.ppt
Sep 23, 2013	Dominion Presentation 09-20-13 *Addressing ISO-NE's Performance Incentives - By Ronald Hart*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep242013/a4a1_dominion_presentation_09_20_13.ppt
Sep 18, 2013	Analysis Group FCM PI Impact Assessment Report September 2013 *Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3b_analysis_group_fcm_pi_impact_assessment_report_09_2013.pdf
Sep 18, 2013	GDF SUEZ PER Elimination Proposal 09-20-13 *Proposal to Eliminate the PER Component of FCM-PI - By Tom Kaslow*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a4_gdf_suez_per_elimination_proposal_09_20_13.pdf
Sep 18, 2013	CT PURA Premium Capacity Plus Proposal 09-17-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a3_ct_pura_premium_capacity_plus_proposal_09_17_13.pdf

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Sep 17, 2013	NextEra FCM PI Proposal #3 09-16-13 *Addition of Annual Stop-Loss*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a2_nextera_fcm_pi_proposal_3_annual_stop_loss_09_16_13.doc
Sep 18, 2013	NRG Presentation 09-20-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a1_nrg_presentation_09_20_13.ppt
Sep 18, 2013	NextEra FCM PI Proposal #2 09-16-13 *Level of Monthly Stop-Loss*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a2_nextera_fcm_pi_proposal_2_monthly_stop_loss_09_16_13.doc
Sep 18, 2013	NextEra FCM PI Proposal #1 09-16-13 *Excused Unavailability for Transmission Outages*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3a2_nextera_fcm_pi_proposal_1_limited_transmission_exemptions_09_16_13.doc
Sep 12, 2013	Analysis Group Presentation 09-11-13 Revision 1 *FCM PI Impact Assessment - Additional Results - By Paul Hibbard and Todd Schatzki*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12f_analysis_group_presentation_09_11_13_r1.ppt
Sep 11, 2013	ISO Memo September 6, 2013 *Updated Responses to NESCOE Questions on ISO's Pay-for-Performance Proposal*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep202013/a3b_iso_memo_09_06_13.pdf
Sep 10, 2013	Agenda Item #2 *FCM PI Financial Assurance*	http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2013/sep162013/2_fcm_pi_fa.pdf
Sep 5, 2013	ISO FCM PI Tariff Changes Guide 09-04-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12d_fcm_pi_tariff_changes_guide_09_04_13.doc
Sep 5, 2013	ISO MR 1 Redlined 09-04-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12d_iso_mr_1_redlined_09_04_13.doc
Sep 5, 2013	ISO Presentation 09-11-13 *FCM Performance Incentives - Financial Assurance Policy Changes - By Marc Montalvo*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12c_iso_presentation_09_11_13.ppt

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Sep 5, 2013	IMM MR 1 Redlined 09-04-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12e_imm_mr_1_redlined_09_04_13.doc
Sep 4, 2013	Dominion Presentation *Addressing ISO-NE's Performance Incentives*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12b_dominion_presentation_pi_alternative.pdf
Sep 4, 2013	ISO Memo September 4, 2013 *FCM Performance Incentives - Performance Payment Rate - By ISO Market Development*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/sep10112013/a12a_iso_memo_09_04_13.pdf
Aug 20, 2013	Analysis Group Presentation 08-08-13 Revision 1 *FCM PI Impact Assessment - Additional Data and NRG Alternative Analysis (Revised August 16, 2013) - By Paul Hibbard and Todd Schatzki*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10c_analysis_group_presentation_08_08_13_r1.ppt
Aug 06, 2013	Dominion Presentation FCM PI Alternative *Addressing ISO-NE's Performance Incentives (information only - no discussion)*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10e_dominion_presentation_pi_alternative.pdf
Aug 06, 2013	NRG Presentation 08-07-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10d_nrg_presentation_08_07_13.ppt
Aug 02, 2013	Draft ISO FCM PI Reference Guide 08-07-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10a_draft_iso_fcm_pi_reference_guide_08_07_13.pdf
Aug 02, 2013	IMM Presentation 08-08-13 FCM PI Mitigation Design - A Strategic Initiative - By Parviz Alivand	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10b_imm_presentation_08_08_13.pdf
Aug 02, 2013	Agenda Item #4.a *FCM PI Financial Assurance*	http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/budgfin_comm/budgfin/mtrls/2013/aug122013/4a_fcm_pi_fa.pdf

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Aug 02, 2013	ISO Memo August 1, 2013 *FCM Performance Incentives - Revised Stop-Loss Value - From ISO Market Development*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10a_iso_memo_08_01_13.pdf
Aug 02, 2013	ISO Presentation 08-08-13 *FCM Performance Incentives - A Strategic Planning Initiative - By Andrew Gillespie, Ron Coutu and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/aug7892013/a10a_iso_presentation_08_08_13.ppt
Jul 10, 2013	Stoddard Presentation 07-11-13 *FCM Performance Incentives - Evaluation and Recommendations - By Robert Stoddard*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12c_stoddard_presentation_07_11_13.ppt
Jul 04, 2013	ISO Memo July 5, 2013 *Operating Reserve Deficiency Information - At Criteria And Extended Results PDF (180k)*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_memo_07_05_13.pdf
Jul 03, 2013	ISO Memo July 3, 2013 *FCM Performance Incentives - Stop Loss Mechanism*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_stop_loss_mechanism_memo_07_03_13.pdf
Jul 03, 2013	Stoddard Analysis of ISO's Performance Incentives Proposal 07-02-13 *Performance Incentives in ISO New England's Forward Capacity Market - Prepared For: NextEra Energy Resources - Prepared By Robert Stoddard / Charles River Associates*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12c_stoddard_on_iso_performance_incentives_07_02_2013.pdf
Jul 03, 2013	Analysis Group Presentation 07-11-13 *FCM PI Impact Assessment Results - By Paul Hibbard*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12b_analysis_group_presentation_07_11_13.ppt
Jul 03, 2013	Draft ISO FCM Performance Incentives Reference Guide 07-10-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_draft_iso_fcm_pi_reference_guide_07_10_13.pdf
Jul 03, 2013	ISO Presentation 07-11-13 *FCM Performance Incentives - A Strategic Planning Initiative - By Andrew Gillespie, Ron Coutu and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jul10112013/a12a_iso_presentation_07_11_13.ppt

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May 29, 2013	IMM Presentation 06-04-13 *FCM Performance Incentives - By Parviz Alivand*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jun452013/a07a_imm_presentation_06_04_13.ppt
May 29, 2013	ISO Memo May 29, 2013 *Operating Reserve Deficiency Information - At Criteria - From Market Development*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jun452013/a07b_iso_memo_05_29_13.pdf
May 29, 2013	Analysis Group Presentation 06-04-13 *FCM PI Impact Assessment Update - Assessment Method, Assumptions and Data - By Paul Hibbard*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jun452013/a07d_analysis_group_presentation_06_04_13.ppt
May 29, 2013	ISO Presentation 06-04-13 *FCM Performance Incentives - By Andrew Gillespie, Ron Coutu and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jun452013/a07b_iso_presentation_06_04_13.ppt
May 17, 2013	Dominion Presentation 05-14-13 Revision 1 *Addressing ISO-NE's Performance Incentives - By Ron Hart*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/may14152013/a04b_dominion_presentation_05_14_13_r1.pdf
May 13, 2013	ISO Presentation 05-14-13 Revision 2 *FCM Performance Incentives - A Strategic Planning Initiative - By Andrew Gillespie, Ron Coutu, and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/may14152013/a04a_iso_presentation_05_14_13_r2.ppt
May 08, 2013	NRG Presentation 05-14-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/may14152013/a04b_nrg_presentation_05_14_13.ppt
Apr 08, 2013	NextEra Presentation 04-10-13 *Discussion Points on ISO's Performance Incentives Proposal - By Fernando DaSilva*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr9102013/a17d_nextera_presentation_04_10_13.ppt
Apr 04, 2013	Dominion Presentation 04-10-13 *Addressing ISO-NE's Performance Incentives - By Ronald Hart*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr9102013/a17d_dominion_presentation_04_10_13.pdf
Apr 03, 2013	ISO Memo April 2, 2013 *Feedback on NRG's Proposals for Performance Incentives - From ISO Market Development*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr9102013/a17d_iso_memo_feedback_on_nrg_proposal_04_02_13.pdf

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Apr 03, 2013	IMM Presentation 04-10-13 *IMM's Discussion on FCM PI - A Strategic Planning Initiative - By Parviz Alivand*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr9102013/a17b_imm_presentation_04_10_13.pdf
Apr 03, 2013	ISO Presentation 04-10-13 *FCM Performance Incentives - A Strategic Planning Initiative - By Andrew Gillespie, Parviz Alivand, Ron Coutu and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr9102013/a17a_iso_presentation_04_10_13.ppt
Apr 03, 2013	Analysis Group Presentation 04-10-13 *FCM Performance Incentives - Framework for Impact Assessment - By Paul Hibbard*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/apr9102013/a17c_analysis_group_presentation_04_10_13.ppt
Mar 15, 2013	IMM Memo March 15, 2013 *Response to Questions on the ISO's Performance Incentive Proposal - From David LaPlante*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_imm_memo_03_15_13.pdf
Mar 15, 2013	ISO Memo March 15, 2013 *External Market Monitor's Letter to NextEra - From Robert Ethier*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_iso_memo_03_15_13.pdf
Mar 12, 2013	Dominion Presentation 03-12-13 Revision 1 *Addressing ISO-NE's Performance Incentives - By Ronald Hart*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_dominion_presentation_03_12_13_r1.pdf
Mar 08, 2013	PSEG Presentation 03-12-13 *"Pay-for-Performance" Forward Capacity Market Re-Design - A View from the Cheap Seats - By Joel Gordon*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_pseg_presentation_03_12_13.ppt
Mar 07, 2013	ISO Presentation 03-12-13 Revision 1 *FCM Performance Incentives - A Strategic Planning Initiative - By Ron Coutu, Andrew Gillespie and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_iso_presentation_03_12_13_r1.ppt
Mar 06, 2013	NRG Presentation 03-12-13 *Market Reform Proposals - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_nrg_presentation_03_12_13.ppt

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Mar 05, 2013	ISO Memo March 5, 2013 *Operating Reserve Deficiency Information - Historical Data - From ISO Market Development*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_iso_reserves_memo_03_05_13.pdf
Mar 05, 2013	IMM Presentation 03-12-13 *IMM's Opinion on FCM PI - A Strategic Planning Initiative - By Parviz Alivand*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_imm_presentation_03_12_13.ppt
Mar 05, 2013	Potomac Economics Memo February 19, 2013 *Questions on ISO New England Performance Incentives Proposal - From David Patton*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_potomac_economics_memo_02_19_13.pdf
Mar 05, 2013	ISO RCPF Activation Data 03-05-13	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_iso_rcpf_activation_data_03_05_13.xlsx
Mar 05, 2013	NEPOOL MP Memo December 21, 2012 *ISO New England Performance Incentives Proposal - From Dominion, Entergy, NextEra, PSEG and TransCanada*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_nepool_mp_memo_12_21_12.doc
Mar 05, 2013	NextEra Presentation 03-12-13 *EMMU Response to Questions on Performance Incentives Proposal - By Fernando DaSilva*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/mar11122013/a14_nextera_presentation_03_12_13.ppt
Mar 01, 2013	ISO Presentation 03-01-13 *Initial Discussion of Impact Analysis Approach - By Robert Ethier*	http://www.iso-ne.com/key_projects/fcm_perf_incentives/mc_mtrls/iso_presentation_03_01_13.pdf
Jan 28, 2013	EnerNOC Presentation 01-29-13 Revision 1 *EnerNOC Feedback on Pay For Performance - By Herb Healy*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b1_enernoc_presentation_01_29_13_r1.pdf
Jan 24, 2013	NRG Presentation 01-29-13 *FCM - And Broader - Market Reforms - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b2_nrg_presentation_01_29_13.ppt

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Jan 23, 2013	ISO Presentation 01-29-13 *FCM Performance Incentives - A Strategic Planning Initiative - By Ron Coutu, Andrew Gillespie and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02a_iso_presentation_01_29_13.ppt
Jan 23, 2013	NRG Alternative Proposal 11-16-12 *FCM Performance Incentives - An Alternative Proposal - By Pete Fuller*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b2_nrg_alternative_proposal_11_16_12.pdf
Jan 23, 2013	Group of Generators Presentation 01-29-13 *FCM Performance Incentives: Initial Areas of Focus - By Capital Power, Dominion, EquiPower, Entergy, Exelon, NextEra and NRG*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2013/jan292013_joint_mtng/a02b3_generator_group_presentation_01_29_13.ppt
Nov 16, 2012	NRG Alternative Proposal 11-16-12 *FCM Performance Incentives*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_nrg_alternative_proposal_11_16_12_.pdf
Nov 12, 2012	ISO Presentation 11-16-12 *FCM Performance Incentives - A Strategic Planning Initiative - By Matthew White, Andrew Gillespie and Ron Coutu*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_iso_presentation_11_16_12.ppt
Nov 12, 2012	ISO Project Charter Memo November 16, 2012 *FCM Performance Incentives - From Andrew Gillespie and Matthew White*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/a02_iso_project_charter_memo_11_16_12.doc
Oct 29, 2012	ISO New England FCM Performance Incentives October 2012	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/fcm_performance_white_paper.pdf
Oct 29, 2012	ISO Memo October 22, 2012 *FCM Performance Incentives - From Gordon van Welie*	http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2012/nov162012/cover_memo_fcm_white_paper.pdf

ATTACHMENT N-1h

Tabulation of NEPOOL Participants Committee Votes
Taken on the ISO-NE and NEPOOL Proposals

DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN WITH RESPECT TO
THE NEPOOL AND ISO-NE PROPOSALS

TOTAL

Participant Name	NEPOOL Proposal	ISO-NE Proposal
GENERATION	14.71	2.86
TRANSMISSION	13.73	2.86
SUPPLIER	15.45	1.29
ALTERNATIVE RESOURCES	3.37	2.66
PUBLICLY OWNED ENTITY	17.17	0.00
END USER	15.85	0.61
% IN FAVOR	80.28	10.28

GENERATION SECTOR

Participant Name	NEPOOL Proposal	ISO-NE Proposal
Dominion Energy Marketing, Inc.	F	O
Entergy Nuclear Power Marketing LLC	A	O
EquiPower Resources Management	A	O
Essential Power, LLC	F	O
GDF SUEZ Energy Mktg. North Amer.	O	F
Generation Group Member	F	0.5
Millennium Power Partners	A	A
NextEra Energy Resources, LLC	A	O
NRG Power Marketing, LLC	F	O
TransCanada Power Marketing Ltd.	F	--
Verso Maine Energy LLC	F	O
IN FAVOR (F)	6	1.5
OPPOSED (O)	1	7.5
TOTAL VOTES	7	9
ABSTENTIONS (A)	4	1

TRANSMISSION SECTOR

Participant Name	NEPOOL Proposal	ISO-NE Proposal
Bangor Hydro-Electric Company	F	O
Central Maine Power Company	A	O
New England Power Company	O	F
The United Illuminating Company	F	O
NU / NSTAR	F	O
Vermont Electric Power Company	F	O
IN FAVOR (F)	4	1
OPPOSED (O)	1	5
TOTAL VOTES	5	6
ABSTENTIONS (A)	1	0

SUPPLIER SECTOR

Participant Name	NEPOOL Proposal	ISO-NE Proposal
BP Energy Company	A	A
Brookfield Energy Marketing Inc./CSC	S	S
Brookfield (70%, when split)	F	A
Cross-Sound Cable (30%, when split)	F	O
Calpine Energy Services	F	O
Competitive Energy Services, LLC	F	O
Consolidated Edison Energy, Inc.	F	O
Dynegy Marketing and Trade, LLC	F	O
Energy America, LLC	A	A
Exelon Generation Company	A	O
Galt Power, Inc.	A	A
Granite Ridge/Merrill Lynch Commodities	F	O
H.Q. Energy Services (U.S.) Inc.	O	F
Hess	A	A
Integrys Energy Services, Inc.	A	A
Kimberly-Clark Corporation	A	O
Linde Energy Services, Inc.	A	O
LIPA	F	O
PPL EnergyPlus, LLC	A	O
PSEG Energy Resources & Trade LLC	F	O
Vitol Inc.	F	O
IN FAVOR (F)	9.0	1.0
OPPOSED (O)	1.0	12.3
TOTAL VOTES	10.0	13.3
ABSTENTIONS (A)	9.0	5.7

ALTERNATIVE RESOURCES SECTOR

Participant Name	NEPOOL Proposal	ISO-NE Proposal
Renewable Generation Sub-Sector		
First Wind Energy Marketing	O	F
Small RG Group Member	F	O
Distributed Generation Sub-Sector		
Conservation Services Group	A	O
Small DG Group Member	A	O
Load Response Sub-Sector		
EnerNOC, Inc.	O	O
Vermont Energy Investment Corp.	A	O
Small LR Group Member	A	A
LR Provisional Group Voting Member	F	O
IN FAVOR (F)	2	1
OPPOSED (O)	2	6
TOTAL VOTES	4	7
ABSTENTIONS (A)	4	1

DECEMBER 6, 2013 PARTICIPANTS COMMITTEE MEETING
VOTES TAKEN WITH RESPECT TO
THE NEPOOL AND ISO-NE PROPOSALS

PUBLICLY OWNED ENTITY SECTOR

Participant Name	NEPOOL Proposal	ISO-NE Proposal
Ashburnham Municipal Light Plant	A	O
Boylston Municipal Light Dept.	A	O
Braintree Electric Light Department	F	O
Chicopee Municipal Lighting Plant	A	O
Concord Municipal Light Plant	F	O
CT Municipal Electric Energy Coop.	F	O
Groton Electric Light Dept.	A	O
Hingham Municipal Lighting Plant	F	O
Holden Municipal Light Dept.	A	O
Holyoke Gas & Electric Dept.	A	O
Hudson Light and Power Dept.	A	O
Hull Municipal Lighting Plant	A	O
Ipswich Municipal Light Dept.	A	O
Littleton (MA) Electric Light Dept.	F	O
Littleton (NH) Water & Light Dept.	F	O
Mansfield Municipal Electric Dept.	A	O
Marblehead Municipal Light Dept.	A	O
Mass. Municipal Wholesale Electric Co.	A	O
Middleborough Gas and Electric	A	O
Middleton Municipal Electric Dept.	A	O
New Hampshire Electric Coop.	F	O
Paxton Municipal Light Dept.	A	O
Peabody Municipal Light Plant	A	O
Princeton Municipal Light Dept.	A	O
Rowley Municipal Lighting Plant	A	O
Russell Municipal Light Department	A	O
Shrewsbury's Electric & Cable Ops.	A	O
South Hadley Electric Light Dept.	A	O
Sterling Municipal Electric Light	A	O
Taunton Municipal Lighting Plant	F	O
Templeton Municipal Lighting Plant	A	O
Vermont Electric Cooperative	F	O
VT Public. Power Supply Authority	F	O
Wakefield Municipal Gas and Light	A	O
Wallingford, CT PUC Elec. Div.	F	O
Wellesley Municipal Light Plant	F	O
W. Boylston Municipal Lighting Plant	A	O
Westfield Gas & Electric Light Dept.	A	O
IN FAVOR (F)	12	0
OPPOSED (O)	0	38
TOTAL VOTES	12	38
ABSTENTIONS (A)	26	0

END USER SECTOR

Participant Name	NEPOOL Proposal	ISO-NE Proposal
Cianbro Companies	F	O
Connecticut Office of Consumer Counsel	F	O
Conservation Law Foundation	O	F
Corinth Wood Pellets, LLC	F	O
Dragon Products Company	F	O
Elektrisola, Inc.	F	O
Environment Northeast	A	O
Fairchild Semiconductor Corporation	F	O
Food City, Inc.	F	O
Hardwood Products Company	F	O
Harvard Dedicated Energy Limited	F	O
High Liner Foods (USA) Inc.	F	O
Industrial Energy Consumer Group	F	O
LaBree's Inc.	F	O
Maine Public Advocate Office	F	O
Maine Skiing, Inc.	F	O
Marden's Inc.	F	O
Mass. Attorney General's Office	F	O
MoArk, LLC	F	O
NH Office of Consumer Advocate	A	O
PalletOne of Maine	F	O
PowerOptions, Inc.	F	O
Praxair, Inc.	A	O
St. Anselm College	F	O
Shipyard Brewing Co., LLC	F	O
The Energy Consortium	F	O
Union of Concerned Scientists	O	A
Utility Services Inc.	A	A
Westerly Hospital, The	F	O
Z-TECH, LLC	F	O
IN FAVOR (F)	24	1
OPPOSED (O)	2	27
TOTAL VOTES	26	28
ABSTENTIONS (A)	4	2

Attachment N-1i

NEPOOL's blacklined Tariff sheets effective June 1, 2014

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:

Actual Load is the consumption at the Retail Delivery Point for the hour.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of 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.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. The daily bid Blocks in the price-based Real-Time bid will be multiplied by the number of hours in the day 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 risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

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 generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand 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 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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 CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a

Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision 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 compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

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 under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's 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 the day); (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 (for Capacity Commitment Periods commencing on or after June 1, 2017, 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.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.
Capacity Capability Interconnection Standard has the meaning specified in Schedule 22 and Schedule 23 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 Clearing Price Floor is described in Section III.13.2.7.

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, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 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 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 is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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 Requirement is described in Section III.13.7.3.1 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-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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.

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.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A 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.

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 power year, 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 in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of 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 Generating Capacity 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.

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.

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 value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

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 Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation 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 Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

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 Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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 the pumping load associated with pumped storage generators) 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 the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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 or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response 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.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start 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 time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation 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) is the Dispatch Rate expressed in megawatts.

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 Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource's or contract's Supply Offer or Demand Bid 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 Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and 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 Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources,

however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at prices of $1.00/kW-month or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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 Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to 68 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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 generation amount, in MWs, that a generating unit 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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II 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 hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

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 and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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, the Capacity Requirement 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.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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 by 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, and, subject to ISO evaluation, for the

Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 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 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.

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.

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 Generator means a generating unit that the ISO may dispatch within the hour 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) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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.

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 Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as 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 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 $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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 generator that has been registered 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 Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event

Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

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.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) 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 generation 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.

Insufficient Competition is defined in Section III.13.2.8.2 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures" or the "Small Generator Interconnection Procedures" pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

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 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.

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.

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 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.

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 or Demand Bids 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 generating resources 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.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, 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, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an

identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local 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 the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed

Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

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 or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk

power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future

financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response

Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

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 a 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 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 Value of the Demand 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 Value for an Existing Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand 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, which includes 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 a Demand Resource supplier 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 Demand Resource suppliers 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 Value of the 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 a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all 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.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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 Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

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 as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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 Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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.

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.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

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 generating unit that must be paid to Market Participants with an Ownership Share in the unit 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 generating unit 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.13.7.3.1.3.

Non-Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.B of that policy.

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 calculated in accordance with Section VII.B.2(i) 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-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-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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.

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 generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and 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 between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand 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 generating unit asset or Load Asset, where such unit or load 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.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 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 II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

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.

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(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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 Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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 or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

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.

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.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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.

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 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)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, 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(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) 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 Price Response Program is the program described in Appendix E 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.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation 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 adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of 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.5.6.1 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 an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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.

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, for Capacity Commitment Periods commencing on or after June 1, 2017, 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 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.

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 generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand 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.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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 generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand 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 risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

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. 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.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 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. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day 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, or Schedule 23 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.

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 the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

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) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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 O&M Payment is the annual compensation calculated under either Section 5.1 or 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 Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

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 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 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.

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 Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource 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 Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. 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.

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The ISO shall calculate the price of energy at Nodes, Load 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.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors 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 generator 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 generation 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. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, 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. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. 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 locational 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 most recent power flow solution produced by the State Estimator, 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 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of 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.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal 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 most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section

III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, 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 generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy 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; (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 generation 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.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. 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.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding 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 zero for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to zero for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal 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 and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, 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 bid 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; (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 generation 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 generation. The 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 Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, 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 generation at its Economic Maximum Limit, 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 $1,000/MWh;

(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 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 generation, 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 generation, 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 generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation 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 $0/MWh and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation 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 generation; and

(iii) If power balance not achieved in step (ii), set LMP values to zero and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

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 for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load 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 and Reserve Zones and add or subtract Reliability Regions, Load 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. 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 determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, 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 generating Resources and Dispatchable Asset Related Demand Resources 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 create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation

Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource's output necessary to create the additional Operating Reserve or local TMOR from the generating Resource's expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		$250/MWh
System TMOR	minimum TMOR	$~~500~~1000/MWh
	Replacement Reserve	$250/MWh
System TMNSR		$~~850~~1500/MWh
System TMSR		$50/MWh

The RCPFs 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 every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding 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 to be used in settlements.

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 hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as

practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post

final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.1.2.2.4.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The

$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.
For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.
For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project

Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website.

A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff.

A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option,

exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail

to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource

shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation,

then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource's summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section

III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period

associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to opt out of the capacity market at prices at or above $1.00/kW-month during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services

markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to opt out of the capacity market permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form

of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite

costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above $1.00/kW-month, and Permanent De-List Bids Above $1.00/kW-month.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above $1.00/kW-month, and each Permanent De-List Bid above $1.00/kW-month to determine whether the bid is consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.1) and opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.2). Sufficient documentation and information must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs and the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

In the case of a Permanent De-List Bid or an Export Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net risk- adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at

prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

(b) In the case of a Static De-List Bid, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor and greater than $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

III.13.1.2.3.2.1.2. Net Risk-Adjusted Going Forward Costs.

A Static De-List Bid, Export Bid above $1.00/kW-month, or Permanent De-List Bid above $1.00/kW-month shall be considered consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward costs based on a review of the data submitted in the following formula. To the extent

possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{\left(\left[GFC / AA\right] + \left[RF\right] + \left[MR - PER\right]\right) \times InfIndex}{\left(CQ_{Summer}, kw\right) \times \left(2, months\right)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

CQ_{Summer}kW = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

RF = risk factor, in dollars. This value shall be calculated using the following formula:

RF = [(RPC x EFORd) + (P x (Forward Capacity Auction Starting Price – AFCAP) x 12,months)] x CQ_{Summer}kW

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

RPC = replacement power costs rate, in dollars/kW. As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit's daily price to the resource's Real-Time nodal price. For each hour that the resource's nodal price exceeds the PER Proxy Unit's daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit's daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.

P = Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period. This estimate shall be no greater than the EFORd of the resource for the corresponding period used in quantifying going forward costs, and in no case greater than 0.40. The Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.

AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward Capacity Auction clearing prices in the resource's Capacity Zone.

AA = availability adjustment. AA = (1 – EFORd)

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid),this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above $1.00/kW-month, or Permanent De-List Bid above $1.00/kW-month has opportunity costs that support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification. The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall

verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{CostOfCapital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor's review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	**Maine**
HQ Phase I/II External Node	**Rest-of-Pool**
Highgate External Node	**Rest-of-Pool**
NY-NE AC External Node	**Rest-of-Pool**
Cross Sound Cable External Node	**CT**

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO

documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	**MW**	**Contract End Date**
NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same

as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or

controlled directly by the Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets

associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements

of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer

and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no

later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource

Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the

relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail

regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after

the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c)

and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above $1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including

the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs

incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in yer "X", where X is any year after 2015.

New Capacity Show of Interest Submission Window	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Purchased in Each Forward Capacity Auction.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price

associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a "New Capacity Offer") indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \ldots \quad \ldots & , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource's summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of

that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than $1.00/kW-month (or the Start-of-Round Price, if lower than $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b).

Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity

Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the "Total System Capacity") shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the

Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone's Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface's approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone's Local Sourcing Requirement; or

(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-

Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**. For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone's Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above

are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency

Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price

specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability

will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual

reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. For de-list bids, this review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the

Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Permanent De-List Bid as accepted for the Forward Capacity Auction. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund

while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted subject to refund while the rate is reviewed. In no

event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by ISO New England**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(c), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for

which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]

III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that

price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone's Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource's location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9 Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.

The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.

If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.

In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.

III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, "New Capacity Required" shall mean the Capacity Zone's Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, "New Capacity Required" shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone's Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the

Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant's total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant's potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor's

determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids based on the Internal Market Monitor review and the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices

resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3. **[Reserved.]**

III.13.8.4. **[Reserved.]**

Attachment N-1j

NEPOOL's clean Tariff sheets effective June 1, 2014

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:

Actual Load is the consumption at the Retail Delivery Point for the hour.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technologies Regulation Pilot Program is the pilot described in Appendix J to Market Rule 1.

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.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of 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.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. The daily bid Blocks in the price-based Real-Time bid will be multiplied by the number of hours in the day 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 risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

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 generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand 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 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand Resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure

consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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 CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a

Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision 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 compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

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 under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's 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 the day); (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 (for Capacity Commitment Periods commencing on or after June 1, 2017, 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.

Cancellation Fee is defined in Section III.1.10.2(d).

Cancelled Start Credit is a credit calculated pursuant to Section III.F.2.5 of Appendix F to Market Rule 1 as the NCPC Credit due to each Market Participant for pool-scheduled generating Resources that were scheduled by the ISO to start after the close of the Day-Ahead Energy Market and that were cancelled by the ISO prior to their assigned commitment time.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.
Capacity Capability Interconnection Standard has the meaning specified in Schedule 22 and Schedule 23 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 Clearing Price Floor is described in Section III.13.2.7.

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, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 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 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 is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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 Requirement is described in Section III.13.7.3.1 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-to-Service Ratio is defined in Section III.3.2.2(h) of Market Rule 1.

Capacity Transfer Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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.

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.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A 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.

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 power year, 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 in all Load Zones. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Cold Weather Conditions means any calendar day when that day's Effective Temperatures are forecast to be equal to or less than zero degrees Fahrenheit for any single on-peak hour and that day's total Effective Heating Degree Days are forecast to be greater than or equal to 65.

Cold Weather Event means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than or equal to 0 MW for an Operating Day. Cold Weather Events are declared by 1100 two days prior to the Operating Day. A Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists, until such time that the ISO declares a Cold Weather Event.

Cold Weather Warning means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin less than 1,000 MW. In addition, a Cold Weather Warning will be used for all future days within the Seven-Day Forecast when a capacity margin of less than or equal to 0 MW exists for days not yet declared as a Cold Weather Event.

Cold Weather Watch means days when Cold Weather Conditions are forecast to exist and the Seven-Day Forecast indicates a capacity margin greater than or equal to 1,000 MW.

Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

Commission is the Federal Energy Regulatory Commission.

Common Costs are those costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of 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 Generating Capacity 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.

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.

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 value that was determined by the ISO for each Forward Capacity Auction pursuant to the provisions of Section III.13 of Market Rule 1 in effect at the time of that auction.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1 and purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

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 Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation 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 Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

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 Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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 the pumping load associated with pumped storage generators) 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 the electricity consumption of an individual end-use customer at a Retail Delivery Point or the aggregated electricity consumption of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2.

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 or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response 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.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start 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 time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation 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) is the Dispatch Rate expressed in megawatts.

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 Resources, change External Transactions, or change the status of a Dispatchable Asset Related Demand in accordance with the Resource's or contract's Supply Offer or Demand Bid 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 Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output level of each generating Resource and each Dispatchable Asset Related Demand and each Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and 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 Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources,

however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at prices of $1.00/kW-month or lower, as described in Section III.13.2.3.2(d) of Market Rule 1.

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 Maximum Limit or Economic Max is the maximum available output, in MW, of a resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is the maximum of the following values: (i) the Emergency Minimum Limit; (ii) a level supported by environmental and/or operating permit restrictions; or (iii) a level that addresses any significant economic penalties associated with operating at lower levels that can not be adequately represented by three part bidding (Start-Up Fee, No-Load Fee and incremental energy price). In no event shall the Economic Minimum Limit submitted as part of a generating unit's Offer Data be higher than the generation level at which a generating unit's incremental heat rate is minimized (i.e., transitioning from decreasing as output increases to increasing as output increases) except that a Self-Scheduled Resource may modify its Economic Minimum Limit on an hourly basis, as part of its Supply Offer, in order to indicate the desired level of Self-Scheduled MWs.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

EFT is electronic funds transfer.

Effective Heating Degree Days is equal to 68 – (average of max and min Effective Temperature of the day).

Effective Temperature is equal to dry bulb temperature – [windspeed X (65-dry bulb temp)/100].

Elective Transmission Upgrade is a Transmission Upgrade that is participant-funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such Transmission Upgrade), and is not: (i) a Generator Interconnection Related Upgrade; (ii) a Reliability Transmission Upgrade (including a NEMA Upgrade, as appropriate); (iii) an Market Efficiency Transmission Upgrade (including a NEMA Upgrade, as appropriate); or (iv) initially proposed in an Elective Transmission Upgrade Application filed with the ISO in accordance with Section II.47.5 on a date after the addition or modification already has been otherwise identified in the current Regional System Plan (other than as an Elective Transmission Upgrade) in publication as of the date of that application.

Elective Transmission Upgrade Applicant is defined in Section II.47.5 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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 generation amount, in MWs, that a generating unit 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, in order to facilitate: (1) bilateral Energy transactions; (2) self-scheduling of Energy; (3) Interchange Transactions in the Energy Market; and (4) Energy Imbalance Service under Section II 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 hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

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 and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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, the Capacity Requirement 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.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Exempt Real-Time Generation Obligation means that portion of a Market Participant's Real-Time Generation Obligation that is not included in the calculation of Minimum Generation Emergency Credits pursuant to Appendix F of Market Rule 1.

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 by 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, and, subject to ISO evaluation, for the

Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 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 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.

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.

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 Generator means a generating unit that the ISO may dispatch within the hour 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) time to start does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) of Market Rule 1.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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.

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 Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual descending clock auction in the Forward Capacity Market, as 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 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 $14,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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 generator that has been registered 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 Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event

Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

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.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) 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 generation 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.

Insufficient Competition is defined in Section III.13.2.8.2 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement" or the "Small Generator Interconnection Agreement" pursuant to Schedules 22 and 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures" or the "Small Generator Interconnection Procedures" pursuant to Schedules 22 and 23 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22 or Attachment 1 to Schedule 23 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 and Attachment 1 to Schedule 23 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

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 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.

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.

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 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.

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 or Demand Bids 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 generating resources 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.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, 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, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an

identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA**.**

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local 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 the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed

Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

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 or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Generating Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk

power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future

financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response

Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

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 a 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 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 Value of the Demand 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 Value for an Existing Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand 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, which includes 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 a Demand Resource supplier 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 Demand Resource suppliers 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 Value of the 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 a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all 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.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources to operate at or below Economic Minimum Limit, in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Charge means the charge used to allocate the cost of Minimum Generation Emergency Credits. Minimum Generation Emergency Charges are discussed in Appendix F of Market Rule 1.

Minimum Generation Emergency Credits are credits calculated pursuant to Appendix F of Market Rule 1 to compensate certain generating Resources for operation in excess of their Economic Minimum Limits during a Minimum Generation Emergency.

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 Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

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 as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

NCPC Credit means the payment made to a Resource as provided in Section III.3.2.3, Section III.6.4 and Appendix F.

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.

NERC is the North American Electric Reliability Corporation or its successor organization.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Generator Asset is the Generator Asset registered in the energy market at the same Retail Delivery Point as a Demand Response Asset with Distributed Generation capable of delivering Net Supply.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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 Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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.

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.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

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 generating unit that must be paid to Market Participants with an Ownership Share in the unit 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 generating unit 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.13.7.3.1.3.

Non-Commercial Capacity, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.B of that policy.

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 calculated in accordance with Section VII.B.2(i) 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-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-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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.

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 generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and 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 between 0 and the CLAIM10 of a Resource that represents the amount of TMNSR available from the Resource.

Offered CLAIM30 is a Supply Offer value between 0 and the CLAIM30 of a Resource that represents the amount of offline TMOR available from the Resource.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand 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 generating unit asset or Load Asset, where such unit or load 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.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 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 II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

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.

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(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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 Credit is calculated pursuant to Section III.F.2.6.2 of Appendix F to Market Rule 1.

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 or New Demand Resource participate in the Forward Capacity Market, as described in Section III.13.

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.

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.

Queue Position has the meaning specified in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

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.

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 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)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) of Market Rule 1.

Real-Time Commitment Periods are periods of continuous operation bounded by a start up and the earlier to occur of a shut-down or a unit trip used to determine eligibility for Real Time NCPC Credit.

Real-Time Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, 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(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) 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 Price Response Program is the program described in Appendix E 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.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation 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 adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of 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.5.6.1 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 an Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific generating unit with appropriate telecommunications, control and response capability to increase or decrease its output in response to a regulating control signal, in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures.

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 Capability (REGCAP) means the amount of Regulation capability available on a Market Participant's Resource as calculated by the ISO based upon that Resource's Automatic Response Rate and the available regulating range as specified in ISO New England Manual 11 – Market Operations.

Regulation Clearing Price is defined in Section III.3.2.2(e) of Market Rule 1.

Regulation High Limit is the maximum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation High Limit may be less than or equal to the unit's Economic Maximum Limit.

Regulation Low Limit is the minimum amount of energy that a generating unit can reliably produce when that unit is providing Regulation. The Regulation Low Limit may be greater than or equal to the unit's Economic Minimum Limit.

Regulation Opportunity Cost is defined in Section III.3.2.2(i) of Market Rule 1.

Regulation Rank Price is calculated in accordance with Section III.1.11.5(b) of Market Rule 1.

Regulation Requirement is the hourly amount of Regulation MWs required by the ISO to maintain system control and reliability as calculated and posted on the ISO website.

Regulation Service Credit is the credit associated with provision of Regulation Service Megawatts and is calculated in accordance with Section III.3.2.2(c) of Market Rule 1.

Regulation Service Megawatts are calculated in accordance with Section III.3.2.2(f) of Market Rule 1.

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.

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, for Capacity Commitment Periods commencing on or after June 1, 2017, 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 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.

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 generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the "Regional Transmission Expansion Plan" or "RTEP") for the year 2002, as approved by ISO New England Inc.'s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission's corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand 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.

Self-Schedule is the action of a Market Participant in committing and/or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to the greater of: (i) the Resource's Economic Minimum Limit; or (ii) the Resource's Minimum Consumption Limit; or (iii) for a generating Resource for which the Regulation Self-Schedule flag is set for the hour and the unit was on Regulation for at least 20 minutes during the applicable hour of the Operating Day, the median value of all Regulation setpoints (Desired Dispatch Point) used by the Resource while regulating.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that office.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Seven-Day Forecast has the meaning specified in Section III.H.3.3(a).

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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 generating unit to Market Participants with an Ownership Share in the unit each time the unit is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand 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 risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

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. 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.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 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. The daily bid Blocks in the price-based Real-Time offer/bid will be multiplied by the number of hours in the day 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, or Schedule 23 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.

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 the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO, and is provided by generating units that are either electrically synchronized or not electrically synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of a generating unit that can be converted fully into energy within ten minutes from the request of the ISO or a Dispatchable Asset Related Demand pump that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO, and is provided by generating units and Dispatchable Asset Related Demand pumps electrically synchronized to the New England Transmission System.

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) means the reserve capability of a generating unit that can be converted fully into energy within thirty minutes from the request of the ISO, and is provided by generating units that are either not electrically synchronized or synchronized to the New England Transmission System or the reserve capability of a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption.

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.

Time-on-Regulation Credit is the credit associated with provision of Time-on-Regulation Megawatts and is calculated in accordance with Section III.3.2.2(b) of Market Rule 1.

Time-on-Regulation Megawatts is the amount of Regulation capability provided during one hour calculated in accordance with Section III.3.2.2(g) of Market Rule 1.

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 O&M Payment is the annual compensation calculated under either Section 5.1 or 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 Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

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 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 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.

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 Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource 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 Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources. 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.

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The ISO shall calculate the price of energy at Nodes, Load 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.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors 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 generator 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 generation 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. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, 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. As described in Section III.2.4, every offer of energy by a Market Participant from a generating Resource, an External Transaction purchase Resource and a Dispatchable Asset Related Demand Resource that is following economic dispatch instructions of the ISO will be utilized in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. 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 locational 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 most recent power flow solution produced by the State Estimator, 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 Determination of Energy Offers Used in Calculating Real-Time Prices and Real-Time Reserve Clearing Prices.

(a) During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices derived in accordance with this Section shall be determined every five minutes and integrated hourly values of 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.

(b) To determine the energy offers submitted to the New England Markets that shall be used during the Operating Day to calculate the Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall determine which generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources are following its economic dispatch instructions. A generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource will be considered to be following economic dispatch instructions and shall be included in the calculation of Real-Time Prices if:

(i) the applicable Supply Offer price submitted by a Market Participant for energy from the generating Resource or External Transaction purchase is less than or equal to the Dispatch Rate associated with that generating Resource or External Transaction purchase; and

(ii) the applicable Demand Bid price submitted by a Market Participant for energy from the Dispatchable Asset Related Demand Resource is greater than or equal to the Dispatch Rate associated with that Dispatchable Asset Related Demand Resource; and

(iii) the generating Resource, other than a Fast Start Generator, is operating above its Economic Minimum Limit; or

(iv) the Fast Start Generator is operating at or above its Economic Minimum Limit and the applicable Supply Offer price submitted by a Market Participant for energy from the Fast Start Generator is less than or equal to the Dispatch Rate associated with that Fast Start Generator; or

(v) the generating Resource, External Transaction purchase or Dispatchable Asset Related Demand Resource is specifically requested to operate or reduce consumption by the ISO's dispatcher and the associated energy offers or bids submitted are otherwise eligible to be included in the calculation of Real-Time Locational Marginal Prices.

(c) In determining whether a generating Resource or External Transaction purchase satisfies the condition described in III.2.4(b), the ISO will determine the Supply Offer price associated with an energy offer by comparing the actual megawatt output of the generating unit or External Transaction purchase with the Market Participant's Supply Offer price curve for that generating unit or External Transaction purchase. Because of practical generator response limitations, a generating unit whose megawatt output is not more than ten percent above the megawatt level specified in the Supply Offer price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy price offer used in the calculation of Real-Time Prices shall not exceed the applicable Dispatch Rate.

(d) In determining whether a Dispatchable Asset Related Demand Resource satisfies the condition described in III.2.4(b), the ISO will determine the Demand Bid price associated with a Demand Bid by comparing the actual megawatt consumption of the Dispatchable Asset Related Demand Resource with the Market Participant's Demand Bid price curve for that Dispatchable Asset Related Demand Resource. Because of practical Dispatchable Asset Related Demand Resource response limitations, a Dispatchable Asset Related Demand Resource whose megawatt consumption is greater than or equal to ninety percent of the megawatt level specified in the Demand Bid price curve for the applicable Dispatch Rate shall be deemed to be following economic dispatch instructions, but the energy demand bid price used in the calculation of Real-Time Prices shall not be lower than the applicable Dispatch Rate.

III.2.5 Calculation of Real-Time Nodal 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 most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section

III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, given actual system conditions, a set of energy offers and bids, 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 generating Resources, External Transaction purchases and Dispatchable Asset Related Demand Resources with an eligible energy 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; (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 generation 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.2.8; and (5) the effect on transmission losses caused by the increment of load and generation. 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.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions during the preceding 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 zero for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to zero for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Day-Ahead Nodal 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 and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying a linear optimization method to minimize energy, congestion and transmission loss costs, 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 bid 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; (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 generation 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 generation. The 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 Price at that Node.

The process for clearing External Nodes differs from the process for clearing other Nodes in that, 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 generation at its Economic Maximum Limit, 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 $1,000/MWh;

(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 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 generation, 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 generation, 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 generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation 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 $0/MWh and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation 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 generation; and

(iii) If power balance not achieved in step (ii), set LMP values to zero and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

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 for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load 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 and Reserve Zones and add or subtract Reliability Regions, Load 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. 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 determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of Real-Time Nodal Prices specified under Section III.2.5, based on the system conditions described by the most recent power flow solution produced by the State Estimator program and the energy offers that are determined to be eligible for consideration under Section III.2.4 in connection with the Real-Time dispatch. This calculation shall be made by applying an incremental linear optimization method to minimize energy, Operating Reserve, congestion and transmission loss costs, 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 generating Resources and Dispatchable Asset Related Demand Resources 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 create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMSNR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The unit-specific Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a generating Resource shall be determined for each generating Resource that the ISO requires to reduce output in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the generation

Node for the generating Resource and (ii) the offer price associated with the reduction of the generating Resource's output necessary to create the additional Operating Reserve or local TMOR from the generating Resource's expected output level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the LP algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		$250/MWh
System TMOR	minimum TMOR	$1000/MWh
	Replacement Reserve	$250/MWh
System TMNSR		$1500/MWh
System TMSR		$50/MWh

The RCPFs 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 every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions during the preceding 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 to be used in settlements.

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 hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation Clearing Prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices as soon as

practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation Clearing Prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation Clearing Prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post

final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.13.1. Forward Capacity Auction Qualification.

Each resource, or portion thereof, must qualify as a New Generating Capacity Resource (Section III.13.1.1), an Existing Generating Capacity Resource (Section III.13.1.2), a New Import Capacity Resource or Existing Import Capacity Resource (Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (III.13.1.4). Each resource must be at least 100 kW in size to participate in the Forward Capacity Auction, except for resources registered with the ISO prior to the earliest date that any portion of this Section III.13 becomes effective. An offer may be composed of separate resources, pursuant to the provisions of Section II.13.1.5. Pursuant to the provisions of this Section III.13.1, the ISO shall determine a summer Qualified Capacity and a winter Qualified Capacity for each resource, and an FCA Qualified Capacity for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource. A Generating Capacity Resource and a Demand Resource may not both participate in the Forward Capacity Market if located at the same Retail Delivery Point, unless the Generating Capacity Resource is separately metered and its output is added to the metered load as measured at the Retail Delivery Point.

All Project Sponsors must be Market Participants no later than 30 days prior to the deadline for submitting the financial assurance deposit described in Section III.13.1.9.

III.13.1.1. New Generating Capacity Resources.

To participate in a Forward Capacity Auction as a New Generating Capacity Resource, a resource or proposed resource must meet the requirements of this Section III.13.1.1. A New Generating Capacity Resource may elect, during the qualification process, to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only, as described in Section III.13.1.1.2.2.4.

III.13.1.1.1. Definition of New Generating Capacity Resource.

A resource or a portion of a resource that is not a New Import Capacity Resource or Existing Import Capacity Resource (as defined in Section III.13.1.3), or a New Demand Resource or Existing Demand Resource (as discussed in Section III.13.1.4) shall be considered a New Generating Capacity Resource for participation in a Forward Capacity Auction if either: (i) the resource has never previously been counted as a capacity resource as described in Section III.13.1.1.1.1; or (ii) the resource, or a portion thereof, meets one of the criteria in Section III.13.1.1.1.2.

III.13.1.1.1.1. Resources Never Previously Counted as Capacity.

(a) A resource, or a portion thereof, will be considered to have never been counted as a capacity resource if: (i) it never previously received any payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010, except any such payment that is received after the resource has cleared as a New Generating Capacity Resource in a Forward Capacity Auction; and (ii) it has not cleared in any previous Forward Capacity Auction.

(b) [Reserved.]

(c) Where a New Capacity Generating Resource was accepted for participation in the qualification process for a previous Forward Capacity Auction, but cleared less than its summer Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO in accordance with Section III.13.3, the portion of the resource that did not clear in the previous Forward Capacity Auction shall be a New Generating Capacity Resource in the subsequent Forward Capacity Auction. Such a New Generating Capacity Resource must satisfy all of the qualification process requirements applicable to a New Generating Capacity Resource as described in Section III.13.1.1.2, except that the Project Sponsor is not required to resubmit documentation demonstrating site control (Section III.13.1.1.2.2.1) or to resubmit a critical path schedule (Section III.13.1.1.2.2.2) or to provide a new Qualification Process Cost Reimbursement Deposit (Section III.13.1.1.2.1(e)).

III.13.1.1.1.2. Resources Previously Counted as Capacity.

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e). A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:

(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource; or

(b) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purposes of re-powering will be equal to or greater than $200 per kilowatt of the whole resource's summer Qualified Capacity after re-powering, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs; or

(c) Where investment in the resource subsequent to January 1, 2007 and prior to the conclusion of the first Capacity Commitment Period associated with the Capacity Supply Obligation for which treatment as a new resource may be applied, for the purpose of compliance with environmental regulations or permits will be equal to or greater than $100 per kilowatt of the whole resource's summer Qualified Capacity after the investment, the owner of the resource may elect that the whole resource participate in the Forward Capacity Auction as a New Generating Capacity Resource. The $100 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs.

III.13.1.1.1.3. Incremental Capacity of Resources Previously Counted as Capacity.
The owner of a resource previously counted as a capacity resource may elect to have the incremental amount of capacity above the summer Qualified Capacity of the resource at the time of the qualification process participate in the Forward Capacity Auction as a New Generating Capacity Resource, where investment in the resource:

(a) will result, by the start of the Capacity Commitment Period, in an increase in output greater than 2 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, but less than or equal to the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction; or (ii) 40 MW; and

(b) will be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The $200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. These investment costs may include the costs associated with reactivating a resource that was previously deactivated pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and in which investment in the resource was undertaken prior to reactivation. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section does not cause the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement, the Project Sponsor must submit a New Capacity Qualification Package but is not required to submit a New Capacity Show of Interest Form for the incremental amount by the New Capacity Qualification Deadline. If the incremental amount of capacity seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.3 causes the resource to exceed the megawatt amount approved in the resource's Interconnection Agreement or MW amount approved pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), the Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2 for the incremental amount.

III.13.1.1.1.4. De-rated Capacity of Resources Previously Counted as Capacity.

For purposes of the Forward Capacity Market, de-rated capacity of a resource shall be measured by the difference between the summer Qualified Capacity prior to the de-rating of the resource and the most recent summer demonstration of Seasonal Claimed Capability of a resource, as of the fifth Business Day of October. The owner of a resource previously counted as a capacity resource that has been de-rated by at least 2 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) but by no more than the lesser of 20 percent of its summer Qualified Capacity (as an Existing Generating Capacity Resource) or 40 MW for three or more years at the time of the Forward Capacity Auction may elect to have the incremental amount of capacity above the capacity level established while de-rated treated as a New Generating Capacity Resource if it demonstrates that it will be reestablished prior to the start of the Capacity Commitment Period and that the investment in the resource for such purposes shall be equal to or greater than $200 per kilowatt of the amount of the increase in summer Qualified Capacity resulting from the investment. The Project Sponsor must submit a New Capacity Show of Interest Form pursuant to Section III.13.1.1.2.1 and a New Capacity Qualification Package pursuant to Section III.13.1.1.2.2 for the incremental amount of capacity for the relevant Forward Capacity Auction. The

$200 threshold (in base year 2008 dollars) shall be adjusted annually in accordance with the most recent Handy-Whitman Index of Public Utility Construction Costs. The owner of a resource seeking to have the incremental amount of capacity counted as a New Generating Capacity Resource as provided in this Section, must demonstrate based on historical data that the resource previously operated at a level at least 2 percent above the de-rated amount.

III.13.1.1.1.5. Treatment of Resources that are Partially New and Partially Existing.
For purposes of this Section III.13.1, where only a portion of a single resource is treated as a New Generating Capacity Resource, either as a result of partial clearing in a previous Forward Capacity Auction or pursuant to Section III.13.1.1.1.3 or Section III.13.1.1.1.4, then except as otherwise indicated in this Section III.13.1, that portion of the resource shall be treated as a New Generating Capacity Resource, and the remainder of the resource shall be treated as an Existing Generating Capacity Resource.

III.13.1.1.1.6. Treatment of Deactivated and Retired Units.

(a) [Reserved.]

(b) A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation shall, subject to ISO review and acceptance of that reactivation plan, be treated as an Existing Generating Capacity Resource unless that resource satisfies the criteria under Section III.13.1.1.1.2 as a New Generating Capacity Resource. Such reactivation plans must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline. A resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, that submits to the ISO a reactivation plan demonstrating that the resource shall return to Commercial Operation and having a material modification as described in Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions), as applicable, shall be subject to Section III.13.1.1.2.3 (Initial Interconnection Analysis).

III.13.1.1.2. Qualification Process for New Generating Capacity Resources.
For a resource to qualify as a New Generating Capacity Resource, the resource's Project Sponsor must make two separate submissions to the ISO: First, the Project Sponsor must submit a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Second, the Project

Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline. Each of these submissions is described in more detail in this Section III.13.1.1.2. The Project Sponsor must also submit to the ISO an Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff prior to submitting a New Capacity Show of Interest Form during the New Capacity Show of Interest Submission Window. Both the New Capacity Show of Interest Form and the New Capacity Qualification Package are required regardless of the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff. Neither the New Capacity Show of Interest Form nor the New Capacity Qualification Package constitutes an Interconnection Request. A Project Sponsor may withdraw from the qualification process at any time prior to three Business Days before the submission of the financial assurance deposit pursuant to Section III.13.1.9.1 by providing written notification of such withdrawal to the ISO. Any withdrawal, whether pursuant to this provision or as determined by the ISO (for example as described in Section III.13.1.1.2.1 or Section III.13.1.9.3), shall be irrevocable. The Project Sponsor of a withdrawn application is subject to reconciliation of its Qualification Process Cost Reimbursement Deposit described in Section III.13.1.9.3. Upon submission of the financial assurance deposit by the Project Sponsor pursuant to Section III.13.1.9.1, the resource is obligated to participate and will be included in the Forward Capacity Auction at its FCA Qualified Capacity amount at the Forward Capacity Auction Starting Price. None of the provisions of this Section III.13.1, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, supersedes, replaces, or satisfies any of the requirements of Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, except as specifically provided thereunder. Determinations by the ISO pursuant to this Section III.13.1.1.2, including the initial interconnection analysis and the analysis of overlapping interconnection impacts, are for purposes of qualification for participation in the Forward Capacity Auction only, and do not constitute a right or approval to interconnect, and do not guarantee the ability to interconnect.

III.13.1.1.2.1. New Capacity Show of Interest Form.

Except as otherwise provided in this Section III.13.1.1.2.1, for each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit to the ISO a New Capacity Show of Interest Form as described in this Section III.13.1.1.2.1 during the New Capacity Show of Interest Submission Window. After submission of a New Capacity Show of Interest Form, material changes (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff) may not be made to the information contained therein. The New Capacity Show of Interest Form is available on the ISO website.

A New Capacity Show of Interest Form to which a material change has been made shall be considered withdrawn. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

(a) A completed New Capacity Show of Interest Form shall include the following information, to the extent the information is not already provided under an active Interconnection Request under Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, and other such information necessary to evaluate a project: the project name; the Project Sponsor's contact information; the Project Sponsor's ISO customer status; the project's expected Commercial Operation date; the project address or location, and if relevant, asset identification number; the status of the project under the generator interconnection procedures described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff; whether the resource has ever previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010; the capacity (in MW) of the New Generating Capacity Resource; the Economic Minimum Limit (in MW) of the New Generating Capacity Resource; a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21 or some other type); a simple location plan and a one-line diagram of the plant and station facilities, including any known transmission facilities; the location of the proposed interconnection; and other specific project data as set forth in the New Capacity Show of Interest Form. The ISO may waive the submission of any information not required for evaluation of a project. A completed New Capacity Show of Interest Form shall also specify the Queue Position associated with the project pursuant to Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff. Submittal of the Interconnection Request may take place prior to the qualification process described here, but no later than the date on which the New Capacity Show of Interest Form is submitted to the ISO; however, the Interconnection Customer Interconnection Request must still be active and consistent with the project described in the New Capacity Show of Interest Form as well as the New Capacity Qualification Package to be submitted as described in Section III.13.1.1.2.2.

(b) The Project Sponsor must submit with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall have the same meaning as set forth in Schedule 22 or Schedule 23, as applicable, of Section II of the Transmission, Markets and Services Tariff.

A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

(c) In the New Capacity Show of Interest Form, the Project Sponsor must indicate if the New Generating Capacity Resource is incremental capacity associated with a resource that previously had a Capacity Supply Obligation or previously received payment as a capacity resource pursuant to the market rules in effect prior to June 1, 2010 as discussed in Section III.13.1.1.1.3, or if the New Generating Capacity Resource is incremental capacity associated with a resource previously listed as a capacity resource that has been de-rated for three or more years at the time of the Forward Capacity Auction, as discussed in Section III.13.1.1.1.4.

(d) [Reserved.]

(e) With the New Capacity Show of Interest Form, the Project Sponsor must submit the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.1.2.2. New Capacity Qualification Package.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must submit a New Capacity Qualification Package no later than the New Capacity Qualification Deadline, described in Section III.13.1.10. Except as otherwise provided in this Section III.13.1, the New Capacity Qualification Package shall conform to the requirements of this Section III.13.1.1.2.2. The ISO may waive the submission of any information not required for evaluation of a project. No change that may result in a reduction in capacity may be made to a project described in a New Capacity Show of Interest Form or New Capacity Qualification Package between the date that is 150 days before the start of the Forward Capacity Auction and the deadline for qualification determination notifications described in Section III.13.1.1.2.8.

III.13.1.1.2.2.1. Site Control.

For all Forward Capacity Auctions and reconfiguration auctions, the Project Sponsor must submit, with the New Capacity Show of Interest Form, documentation demonstrating that the Project Sponsor has already achieved control of the project site for the duration of the relevant Capacity Commitment Period. Site control shall mean that: (i) the Project Sponsor is the owner in fee simple of the real property on which the project will be located; (ii) the Project Sponsor holds a valid written leasehold interest in the real property on which the project will be located; (iii) the Project Sponsor holds a valid written option,

exercisable solely by the Project Sponsor or its assignee, to purchase or lease property on which the project will be located; or (iv) the Project Sponsor holds a duly executed written contract to purchase or lease the real property on which the project will be located. A resource that has previously been counted as a capacity resource is not required to submit site control documentation.

III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve Commercial Operation as qualified no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the estimated dollar amount of required project financing; (ii) the expected sources of that financing; and (iii) the expected closing date(s) for the project financing.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(d) and that accounts for more than five percent of the total project cost.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (d) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent Commercial Operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

III.13.1.1.2.2.3. Offer Information.

(a) All New Generating Capacity Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Capacity Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that Section.

(b) The Project Sponsor for a New Generating Capacity Resource must indicate in the New Capacity Qualification Package if an offer from the New Generating Capacity Resource may be rationed. A Project Sponsor may specify a single MW quantity at or above the Economic Minimum Limit to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

(c) By submitting a New Capacity Qualification Package, the Project Sponsor certifies that an offer from the New Generating Capacity Resource will not include any anticipated revenues the resource is expected to receive for its capacity cost as a Qualified Generator Reactive Resource pursuant to Schedule 2 the OATT.

III.13.1.1.2.2.4. Capacity Commitment Period Election.

In the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

III.13.1.1.2.2.5. Additional Requirements for Resources Previously Counted As Capacity.

In addition to the information described elsewhere in this Section III.13.1.1.2.2:

(a) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), Section III.13.1.1.1.3 (incremental capacity), or Section III.13.1.1.1.4 (de-rated capacity), the Project Sponsor must include in the New Capacity Qualification Package documentation of the costs associated with the project in sufficient detail

to allow the ISO to determine that the relevant cost threshold (described in Sections III.13.1.1.1.2(b), III.13.1.1.1.3(b), and III.13.1.1.1.4) will be met.

(b) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2(c) (environmental compliance), the Project Sponsor must include in the New Capacity Qualification Package: (i) a detailed description of the specific regulations that it is seeking to comply with and the permits that it must obtain; and (ii) documentation of the costs associated with the project in sufficient detail to allow the ISO to determine that the relevant cost threshold (described in Section III.13.1.1.1.2(c)) will be met.

(c) For each resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Sections III.13.1.1.1.2, III.13.1.1.1.3, or III.13.1.1.1.4, the Project Sponsor must include in the New Capacity Qualification Package detailed information showing how and when the resource will shed its Capacity Supply Obligation to accommodate necessary work on the facility, if necessary. The Project Sponsor must also include the shedding of its Capacity Supply Obligation as an additional milestone in the critical path schedule described in Section III.13.1.1.2.2.2.

III.13.1.1.2.2.6. Additional Requirements for New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

In addition to the information described elsewhere in this Section III.13.1.1.2.2, for each Intermittent Power Resource and Intermittent Settlement Only Resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Generating Capacity Resource, the Project Sponsor must include in the New Capacity Qualification Package:

(a) a claimed summer Qualified Capacity and a claimed winter Qualified Capacity based on the data described in Section III.13.1.1.2.2.6(b);

(b) measured and recorded site-specific summer and winter data relevant to the expected performance of the Intermittent Power Resource and Intermittent Settlement Only Resource (including wind speed data for wind resources, water flow data for run-of-river hydropower resources, and irradiance data for solar resources) that, with the other information provided in the New Capacity Qualification Package, will enable the ISO to confirm the summer and winter Qualified Capacity that the Project Sponsor claims for the Intermittent Power Resource or the Intermittent Settlement Only Resource.

III.13.1.1.2.3. Initial Interconnection Analysis.

(a) For each New Generating Capacity Resource, the ISO shall perform an initial interconnection analysis, including an analysis of overlapping interconnection impacts, based on the information provided in the New Capacity Show of Interest Form and shall determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. The initial interconnection analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures, and will include, but will not be limited to, a power flow analysis and a short circuit analysis. No initial interconnection analysis is required where the total requested Qualified Capacity of a New Generating Capacity Resource pursuant to Sections III.13.1.1.2, III.13.1.1.3, III.13.1.1.4, or III.13.1.1.6 can be realized without a material change (as defined in Section 4.4 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). The ISO will perform the initial interconnection analysis in the form of a group study that will include all the projects that have submitted a New Capacity Show of Interest Form to participate in the same Capacity Commitment Period (as described in Section 4.1 of Schedule 22 and Section 1.5 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff). Participation in an initial interconnection analysis is a requirement for obtaining Capacity Network Resource Interconnection Service in a manner that meets the Capacity Capability Interconnection Standard in accordance with the provisions in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff.

(b) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide the entire amount of capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period, the New Generating Capacity Resource's Qualified Capacity values may be adjusted accordingly, as described in Section III.13.1.1.2.5.

(c) If as a result of the initial interconnection analysis, the ISO determines that the interconnection facilities and upgrades identified in the qualification process that are necessary to enable the New Generating Capacity Resource to provide capacity indicated in the New Capacity Show of Interest Form can not be implemented before the start of the Capacity Commitment Period and the New Generating Capacity Resource can not provide any capacity without those facilities and upgrades, the resource shall not be accepted for participation in the Forward Capacity Auction. In this case, the ISO will provide an explanation of its determination in the qualification determination notification, discussed in Section III.13.1.1.2.8.

(d) If as a result of the initial interconnection analysis, the ISO determines that the New Generating Capacity Resource can provide all or some of the capacity indicated in the New Capacity Show of Interest Form by the start of the Capacity Commitment Period, and if the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1, then in the qualification determination notification, discussed in Section III.13.1.1.2.8, the ISO, after consultation with the applicable Transmission Owner(s) as appropriate, shall include a list of the facilities that may be required to complete the interconnection and time required to construct those facilities by the start of the associated Capacity Commitment Period.

(e) Where, as a result of the initial interconnection analysis, the ISO concludes, after consultation with the Project Sponsor and the applicable Transmission Owner(s), as appropriate, that the capacity indicated in the New Capacity Show of Interest Form can not be interconnected by the commencement of the Capacity Commitment Period, the Forward Capacity Market qualification process for that resource shall be terminated and the ISO will notify the Project Sponsor of such termination.

(f) Where, as a result of the initial interconnection analysis, the ISO determines that because of overlapping interconnection impacts, New Generating Capacity Resources that are otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements of this Section III.13.1 cannot provide the full amount of capacity that they each would otherwise be able to provide (in the absence of the other relevant Existing Generating Capacity Resources and New Generating Capacity Resources seeking to qualify for the Forward Capacity Auction), those New Generating Capacity Resources will be accepted for participation in the Forward Capacity Auction on the basis of their Queue Position, as described in Schedules 22 and 23 of Section II of the Transmission, Markets and Services Tariff, with priority given to resources that entered the queue earlier. Resources with lower priority in the queue may be accepted partially. Starting with the fourth auction, a New Generating Capacity Resource that meets the requirements of this Section III.13.1, but that would not be accepted for participation in the Forward Capacity Auction as a result of overlapping interconnection impacts with another resource having a higher priority in the queue may be accepted for participation in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity Resource, as described in Section III.13.2.3.2(f), provided that the resource having a higher priority in the queue is not a resource offering capacity into the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).

(g) New Generating Capacity Resources, or portions thereof, shall not be considered to have met their Capacity Supply Obligation for the purposes of this Forward Capacity Market and shall not receive compensation if any upgrades to be completed by the Project Sponsor required to remove overlapping interconnection impacts as identified in (f) have not been completed, including, any upgrades identified in a restudy pursuant to Section 3.2.1.3 of Schedule 22 and Section 1.7.1.3 of Schedule 23 of Section II of the Transmission, Markets and Services Tariff and, if necessary, requests for the interconnection of an Elective Transmission Upgrade, in time for the Capacity Commitment Period unless the Capacity Supply Obligation is appropriately covered.

III.13.1.1.2.4. Evaluation of New Capacity Qualification Package.

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource or Intermittent Settlement Only Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

III.13.1.1.2.5. Qualified Capacity for New Generating Capacity Resources.

III.13.1.1.2.5.1. New Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource that has cleared in the Forward Capacity Auction shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification, and possibly as modified pursuant to Section III.13.1.1.2.3(b). The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.2. [Reserved]

III.13.1.1.2.5.3. New Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

The summer Qualified Capacity and winter Qualified Capacity of a New Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be the summer Qualified Capacity and winter Qualified Capacity claimed by the Project Sponsor pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e). The FCA Qualified Capacity for such a resource shall be equal to the resource's summer Qualified Capacity, as adjusted to account for applicable offers composed of separate resources.

III.13.1.1.2.5.4. New Generating Capacity Resources Partially Clearing in a Previous Forward Capacity Auction.

Where, as discussed in Section III.13.1.1.1.1(c), a New Generating Capacity Resource was accepted for participation in a previous Forward Capacity Auction, but cleared less than its summer or winter Qualified Capacity in that previous Forward Capacity Auction and is having its critical path schedule monitored by the ISO as described in Section III.13.3, its summer and winter Qualified Capacity as a New Generating Capacity Resource in the instant Forward Capacity Auction shall be the summer and winter Qualified Capacity from the previous Forward Capacity Auction minus the amount of capacity clearing from the New Generating Capacity Resource in the previous Forward Capacity Auction. The FCA Qualified Capacity for such a resource shall be the lesser of the resource's summer Qualified Capacity and winter Qualified Capacity, as adjusted to account for applicable offers composed of separate resources. The amount of capacity clearing in a Forward Capacity Auction from a New Generating Capacity Resource shall be treated as an Existing Generating Capacity Resource in subsequent Forward Capacity Auctions.

III.13.1.1.2.6. [Reserved.]

III.13.1.1.2.7. Opportunity to Consult with Project Sponsor.

In its review of a New Capacity Show of Interest Form or a New Capacity Qualification Package, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the qualification materials resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the qualification materials if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process. In addition, the ISO or the Project Sponsor may confer to seek clarification, to gather additional necessary information, or to address questions or concerns prior to the ISO's final determination and notification of qualification.

III.13.1.1.2.8. Qualification Determination Notification for New Generating Capacity Resources.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to Project Sponsors or Market Participants, as applicable, for each New Generating Capacity Resource indicating:

(a) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the initial interconnection analysis made pursuant to Section III.13.1.1.2.3, and if not accepted, an explanation of the reasons the New Generating Capacity Resource was not accepted in the initial interconnection analysis;

(b) whether the New Generating Capacity Resource has been accepted for participation in the Forward Capacity Auction as a result of the New Capacity Qualification Package evaluation made pursuant to Section III.13.1.1.2.4, and if not accepted, an explanation of the reasons the New Generating Capacity Resource's New Capacity Qualification Package was not accepted;

(c) if accepted for participation in the Forward Capacity Auction, a list of the facilities that may be required to complete the interconnection for purposes of providing capacity and time required to construct those facilities by the start of the associated Capacity Commitment Period, as discussed in Section III.13.1.1.2.3(d);

(d) if accepted for participation in the Forward Capacity Auction, the New Generating Capacity Resource's summer Qualified Capacity and winter Qualified Capacity, as determined pursuant to Section III.13.1.1.2.5;

(e) if accepted for participation in the Forward Capacity Auction, but subject to the provisions of Section III.13.1.1.2.3(f) (where not all New Generating Capacity Resources can be interconnected due to their combined effects on the New England Transmission System), a description of how the New Generating Capacity Resource shall participate in the Forward Capacity Auction, including, for the fourth and future auctions: (i) whether the resource shall participate as a Conditional Qualified New Generating Capacity Resource; (ii) for the notification to a Conditional Qualified New Generating Capacity Resource, the Queue Position of the associated resource with higher queue priority; and (iii) for the notification to a resource with higher queue priority than a Conditional Qualified New Generating Capacity Resource, the Queue Position of the Conditional Qualified New Generating Capacity Resource; and

(f) if accepted for participation in the Forward Capacity Auction and requesting to submit offers at prices below the relevant Offer Review Trigger Price pursuant to Section III.13.1.1.2.2.3, the Internal Market Monitor's determination regarding whether the requested offer price is consistent with the long run average costs of that New Generating Capacity Resource.

III.13.1.2. Existing Generating Capacity Resources.

An Existing Generating Capacity Resource, as defined in Section III.13.1.2.1, may participate in the Forward Capacity Auction pursuant to the provisions of this Section III.13.1.2.

III.13.1.2.1. Definition of Existing Generating Capacity Resource.

Any resource that does not satisfy the criteria for participating in the Forward Capacity Auction as a New Generating Capacity Resource (Section III.13.1.1), as an Existing Import Capacity Resource or New Import Capacity Resource (Section III.13.1.3), or as a New Demand Resource or Existing Demand Resource (Section III.13.1.4) shall be an Existing Generating Capacity Resource.

III.13.1.2.2. Qualified Capacity for Existing Generating Capacity Resources.

III.13.1.2.2.1. Existing Generating Capacity Resources Other Than Intermittent Power Resources and Intermittent Settlement Only Resources.

III.13.1.2.2.1.1. Summer Qualified Capacity.

The summer Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. For the first Forward Capacity Auction, the summer Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's summer Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five summer Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four summer Seasonal Claimed Capability ratings, then the summer Qualified Capacity for that Existing Generating Capacity Resource shall be equal to the median of all of that Existing Generating Capacity Resource's previous summer Seasonal Claimed Capability ratings, as of the fifth Business Day in October of each year, with only positive summer ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.1.2. Winter Qualified Capacity.

The winter Qualified Capacity of an Existing Generating Capacity Resource that is not an Intermittent Power Resource or an Intermittent Settlement Only Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. For the first Forward Capacity Auction, the winter Qualified Capacity of an Existing Generating Capacity Resource shall be equal to the median of that Existing Generating Capacity Resource's winter Seasonal Claimed Capability ratings from the most recent four years, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. Where an Existing Generating Capacity Resource has fewer than five winter Seasonal Claimed Capability ratings, or in the case of the first Forward Capacity Auction, fewer than four winter Seasonal Claimed Capability ratings, then the winter Qualified Capacity for that Existing Generating Capacity Resource

shall be equal to the median of all of that Existing Generating Capacity Resource's previous winter Seasonal Claimed Capability ratings, as of the fifth Business Day in June of each year, with only positive winter ratings included in the median calculation. If for an Existing Generating Capacity Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2. Existing Generating Capacity Resources that are Intermittent Power Resources and Intermittent Settlement Only Resources.

Intermittent Power Resources and Intermittent Settlement Only Resources are defined as wind, solar, run of river hydro and other renewable resources that do not have control over their net power output. Wind and solar resources shall be qualified as Intermittent Power Resources or Intermittent Settlement Only Resources. The summer and winter Qualified Capacity for an Existing Generating Capacity Resource that is an Intermittent Power Resource or Intermittent Settlement Only Resource shall be calculated as follows:

III.13.1.2.2.2.1. Summer Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resource.

(a) With regard to any Forward Capacity Auction, for each of the previous five summer periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Summer Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full summer periods, the ISO shall determine the median of the Intermittent Power Resource's net output in each of the previous summer periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a summer period. If the Intermittent Power Resource or Intermittent Settlement Only Resource began Commercial Operation after the 2006 summer period and prior to the first Forward Capacity Auction, its summer Qualified Capacity shall be established pursuant to Section III.13.1.1.2.2.6, as confirmed by the ISO pursuant to Section III.13.1.1.2.4(e).

(b) The Intermittent Power Resource's or Intermittent Settlement Only Resource's summer Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.1(a).

(c) The Summer Intermittent Reliability Hours shall be hours ending 1400 through 1800 each day of the summer period (June through September) and all summer period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive summer Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation, then the Existing Generating Capacity Resource's summer Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.2.2. Winter Qualified Capacity for an Intermittent Power Resource and Intermittent Settlement Only Resources.

(a) With regard to any Forward Capacity Auction, for each of the previous five winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in the Winter Intermittent Reliability Hours. If the Intermittent Power Resource or Intermittent Settlement Only Resource has not been in Commercial Operation for the requisite five full winter periods, the ISO shall determine the median of the Intermittent Power Resource's and Intermittent Settlement Only Resource's net output in each of the previous winter periods, or portion thereof if the Intermittent Power Resource or Intermittent Settlement Only Resource achieved Commercial Operation during a winter period.

(b) The Intermittent Power Resource's and Intermittent Settlement Only Resource's winter Qualified Capacity shall be the average of the median numbers determined in Section III.13.1.2.2.2.2(a).

(c) The Winter Intermittent Reliability Hours shall be hours ending 1800 and 1900 each day of the winter period (October through May) and all winter period hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was in an import-constrained Capacity Zone, all Shortage Events in that Capacity Zone.

(d) If for an Existing Generating Capacity Resource that is an Intermittent Power Resource or an Intermittent Settlement Only Resource there are no previous positive winter Seasonal Claimed Capability ratings because the Existing Generating Capacity Resource has not yet achieved Commercial Operation,

then the Existing Generating Capacity Resource's winter Qualified Capacity shall be equal to the amount of capacity clearing from the resource as a New Generating Capacity Resource in previous Forward Capacity Auctions.

III.13.1.2.2.3. Qualified Capacity Adjustment for Partially New and Partially Existing Resources.

(a) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the summer Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's summer Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.1, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the summer Qualified Capacity associated with the Existing Generating Capacity Resource.

(b) Where an Existing Generating Capacity Resource is associated with a New Generating Capacity Resource that was accepted for participation in a previous Forward Capacity Auction qualification process and that cleared in a previous Forward Capacity Auction, then in each subsequent Forward Capacity Auction until the New Generating Capacity Resource achieves Commercial Operation the winter Qualified Capacity of that Existing Generating Capacity Resource shall be the sum of [the median of that Existing Generating Capacity Resource's positive winter Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day of June of each year, calculated in a manner consistent with Section III.13.1.2.2.1.2] plus [the amount of the New Generating Capacity Resource's capacity clearing in previous Forward Capacity Auctions]. After the New Generating Capacity Resource achieves Commercial Operation, the Existing Generating Capacity Resource's winter Qualified Capacity shall be calculated as described in Section III.13.1.2.2.1.2, except that no data from the time period prior to the New Generating Capacity Resource's Commercial Operation date shall be used to determine the winter Qualified Capacity associated with the Existing Generating Capacity Resource.

III.13.1.2.2.4. Adjustment for Significant Decreases in Capacity Prior to the Existing Capacity Qualification Deadline.

Where the most recent summer Seasonal Claimed Capability, as of the fifth Business Day in October, of an Existing Generating Capacity Resource that is not a Settlement Only Resource, Intermittent Power Resource, or Intermittent Settlement Only Resource is below its summer Qualified Capacity, as determined pursuant to Section III.13.1.2.2.1.1, by more than the lesser of 20 percent of that summer Qualified Capacity or 40 MW, then the Lead Market Participant must elect one of the three treatments described in this Section III.13.1.2.2.4 by the Existing Capacity Qualification Deadline. If the Lead Market Participant makes no election, or elects treatment pursuant to Section III.13.1.2.2.4(b) or Section III.13.1.2.2.4(c) and fails to meet the associated requirements, then the treatment described in Section III.13.1.2.2.4(a) shall apply.

(a) A Lead Market Participant may elect, for the purposes of the Forward Capacity Auction only, to have the Existing Generating Capacity Resource's summer Qualified Capacity set to the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October, provided that the Lead Market Participant has furnished evidence regarding the cause of the de-rating.

(b) A Lead Market Participant may elect: (i) to submit a Static De-List Bid or a Permanent De-List Bid for the difference between the summer Qualified Capacity calculated pursuant to Section III.13.1.2.2.1.1 and the most recent summer Seasonal Claimed Capability as of the fifth Business Day in October; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section III.13.1.2.2.1.1 for the Forward Capacity Auction.

(c) A Lead Market Participant may elect: (i) to submit a critical path schedule as described in Section III.13.1.1.2.2.2, modified as appropriate, describing the measures that will be taken and showing that the Existing Generating Capacity Resource will be able to provide an amount of capacity consistent with the summer Qualified Capacity as calculated pursuant to Section by the start of the relevant Capacity Commitment Period; and (ii) to have the Existing Generating Capacity Resource's summer Qualified Capacity remain as calculated pursuant to Section for the Forward Capacity Auction. For an Existing Generating Capacity Resource subject to this election, the critical path schedule monitoring provisions of Section III.13.3 shall apply.

III.13.1.2.2.5. Adjustment for Certain Significant Increases in Capacity.

Where an Existing Generating Capacity Resource that is not a Settlement Only Resource, meets the requirements of Section III.13.1.1.1.3(a) but not the requirements of Section III.13.1.1.1.3(b), the Lead Market Participant may elect to have the Existing Generating Capacity Resource's summer Qualified Capacity be the sum of [the median of that Existing Generating Capacity Resource's positive summer Seasonal Claimed Capability ratings from the most recent five years, as of the fifth Business Day in October of each year, calculated in a manner consistent with Section III.13.1.2.2.1.1] plus [the amount of incremental capacity as described in Section III.13.1.1.1.3(a)]; provided, however, that the Lead Market Participant must abide by all other provisions of this Section III.13 applicable to a resource that is a New Generating Capacity Resource pursuant to Section III.13.1.1.1.3. Such an election must be made in writing and must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.2.2.5.1. [Reserved.]

III.13.1.2.2.5.2. Requirements for an Existing Generating Capacity Resource, Existing Demand Resource or Existing Import Capacity Resource Having a Higher Summer Qualified Capacity than Winter Qualified Capacity.

Where an Existing Generating Capacity Resource, Existing Demand Resource, or Existing Import Capacity Resource (other than an Intermittent Power Resource or an Intermittent Settlement Only Resource) has a summer Qualified Capacity that exceeds, by the threshold specified below, its winter Qualified Capacity, both as calculated pursuant to this Section III.13.1.2.2, then that resource must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or (ii) submit a Static De-List Bid or a Permanent De-List Bid in an Existing Capacity Qualification Package for at least the difference between the summer Qualified Capacity and the winter Qualified Capacity, at the Forward Capacity Auction Starting Price. If the Lead Market Participant makes no election, the ISO shall submit a Static De-List Bid on behalf of the resource (with all payments, charges, rights, obligations, and other results associated with such bid applying to the resource as if the resource itself had submitted the bid) for the difference between the resource's summer Qualified Capacity and the winter Qualified Capacity at the Forward Capacity Auction Starting Price. The Internal Market Monitor shall review each bid made pursuant to this Section III.13.1.2.2.5.2, and if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Bids made pursuant to this Section III.13.1.2.2.5.2 shall be subject to a reliability review as described in Section

III.13.2.5.2.5, as required. This Section III.13.1.2.2.5.2 shall not apply if the summer Qualified Capacity of a resource is greater than the winter Qualified Capacity of that resource by less than the lesser of: (i) 2 MW, or (ii) two percent of the summer Qualified Capacity of that resource.

III.13.1.2.3. Qualification Process for Existing Generating Capacity Resources.

For each Existing Generating Capacity Resource, no later than 15 Business Days before the Existing Capacity Qualification Deadline, the ISO will notify the resource's Lead Market Participant of the resource's summer Qualified Capacity and winter Qualified Capacity and the Load Zone in which the Existing Generating Capacity Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Generating Capacity Resource does not accurately reflect the determination described in Section III.13.1.2.2, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. The ISO shall notify the Lead Market Participant of the outcome of any such challenge no later than 5 Business Days before the Existing Capacity Qualification Deadline. If an Existing Generating Capacity Resource does not submit a Static De-List Bid, an Export Bid, an Administrative Export De-List Bid, or a Permanent De-List Bid in the Forward Capacity Auction qualification process, then the resource shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c).

III.13.1.2.3.1. Existing Capacity Qualification Package.

A resource that previously has been deactivated pursuant Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) and seeks to reactivate and participate in the Forward Capacity Market as an Existing Generating Capacity Resource must submit a reactivation plan no later than 10 Business Days before the Existing Capacity Qualification Deadline, as described in Section III.13.1.1.1.6(b). All Static De-List Bids, Export Bids, Administrative Export De-List Bids, and Permanent De-List Bids in the Forward Capacity Auction must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, as described in this Section III.13.1.2.3.1. All Static De-List Bids, Permanent De-List Bids, Export Bids, and Administrative Export De-List Bids submitted in the qualification process may not be modified or withdrawn after the Existing Capacity Qualification Deadline, and if accepted by the ISO shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). An Existing Generating Capacity Resource may not submit a Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Permanent De-List Bid for an amount of capacity greater than its summer Qualified Capacity. Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period

associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. For a single resource, a Lead Market Participant may combine a Static De-List Bid, an Export Bid, and an Administrative Export De-List Bid; a Permanent De-List Bid may not be combined with any other type of de-list or export bid. All Static De-List Bids and Permanent De-List Bids submitted under Section III.13.1.2.2.4(b) associated with a significant decrease in capacity must be identified in the Existing Capacity Qualification Package.

Static De-List Bids, Export Bids and Permanent De-List Bids may elect to be rationed (as described in Section III.13.2.6, however, an Export Bid is always subject to potential rationing where the associated external interface binds). Where a Lead Market Participant submits any combination of Static De-List Bid and Export Bid for a single resource, each of those bids must have the same rationing election. Where a Lead Market Participant submits any combination of Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

III.13.1.2.3.1.1. Static De-List Bids.

An Existing Generating Capacity Resource, or a portion thereof, seeking to opt out of the capacity market at prices at or above $1.00/kW-month during a single Capacity Commitment Period may submit a Static De-List Bid in the associated Forward Capacity Auction. A Static De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Each Static De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Static De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Static De-List Bids are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Static De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services

markets during the Capacity Commitment Period (except for necessary audits or tests). Static De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.2. Permanent De-List Bids.

An Existing Generating Capacity Resource seeking to opt out of the capacity market permanently beginning at the start of a particular Capacity Commitment Period may submit a Permanent De-List Bid in the associated Forward Capacity Auction. A Permanent De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits a Permanent De-List Bid for the resource's full summer Qualified Capacity. Each Permanent De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. All Permanent De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Permanent De-List Bids above $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional documentation described in that section. With the submission of a Permanent De-List Bid, the Existing Generating Capacity Resource must notify the ISO if the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period and thereafter. Permanent De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b). A resource whose Permanent De-List Bid clears in the Forward Capacity Auction is precluded from subsequent participation in the Forward Capacity Market unless it qualifies as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2.

III.13.1.2.3.1.3. Export Bids.

An Existing Generating Capacity Resource within the New England Control Area other than an Intermittent Power Resource or an Intermittent Settlement Only Resource seeking to export all or part of its capacity during a Capacity Commitment Period may submit an Export Bid in the associated Forward Capacity Auction. An Export Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. All Export Bids are subject to a reliability review as described in Section III.13.2.5.2.5. Export Bids above $1.00/kW-month are subject to review by the Internal Market Monitor pursuant to Section III.13.1.2.3.2 and must include the additional information described in that Section. Each Export Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, and must be in the form

of a curve (up to five price-quantity pairs) associated with a specific Existing Generating Capacity Resource. The curve may in no case increase the quantity offered as the price decreases. Each price-quantity pair must be less than the Forward Capacity Auction Starting Price. The Existing Capacity Qualification Package for each Export Bid must also specify the interface over which the capacity will be exported. Export Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.4. Administrative Export De-List Bids.

An Existing Generating Capacity Resource other than an Intermittent Power Resource or an Intermittent Settlement Only Resource subject to a multiyear contract to sell capacity outside of the New England Control Area during the Capacity Commitment Period that either: (i) cleared as an Export Bid in a previous Forward Capacity Auction for a Capacity Commitment Period within the duration of the contract; or (ii) entered into a contract prior to April 30, 2007 to sell capacity outside of the New England Control Area during the Capacity Commitment Period, may submit an Administrative Export De-List Bid in the associated Forward Capacity Auction. An Administrative Export De-List Bid may not result in a resource's Capacity Supply Obligation being less than its Economic Minimum Limit except where the resource submits de-list and export bids totaling the resource's full summer Qualified Capacity. Unless reviewed as an Export Bid in a previous Forward Capacity Auction, an Administrative Export De-List Bid is subject to a reliability review prior to clearing in a Forward Capacity Auction, as described in Section III.13.2.5.2.5, and is subject to review by the Internal Market Monitor in the first Forward Capacity Auction in which it participates, pursuant to Section III.13.1.7. Both the reliability review and the review by the Internal Market Monitor shall be conducted once and shall remain valid for the multiyear contract period. Each Administrative Export De-List Bid must be detailed in an Existing Capacity Qualification Package submitted to the ISO no later than the Existing Capacity Qualification Deadline, must be associated with a specific Existing Generating Capacity Resource, and must indicate the quantity of capacity subject to the bid. The Existing Capacity Qualification Package for each Administrative Export De-List Bid must also specify the interface over which the capacity will be exported, and must include documentation demonstrating a contractual obligation to sell capacity outside of the New England Control Area during the whole Capacity Commitment Period. Administrative Export De-List Bids, if accepted, shall be entered into the Forward Capacity Auction pursuant to Section III.13.2.3.2(b).

III.13.1.2.3.1.5. Non-Price Retirement Request

III.13.1.2.3.1.5.1. Description of Non-Price Retirement Request.

A Non-Price Retirement Request is a binding request to retire all or part of a Generating Capacity Resource. Non-Price Retirement Requests will be approved subject to review for reliability impacts under Section III.13.2.5.2.5. Even if not approved, a resource that has submitted a Non-Price Retirement Request may retire in whole or in part, as applicable, pursuant to Section III.13.2.5.2.5.3(a)(iii). Once submitted, a Non-Price Retirement Request may not be withdrawn. A Non-Price Retirement Request supersedes any prior de-list bid for the same Capacity Commitment Period.

III.13.1.2.3.1.5.2. Timing Requirements.

The request must be submitted to the ISO between the Existing Capacity Qualification Deadline and 120 days prior to the date of the relevant Forward Capacity Auction. In the case of a resource that has a Permanent De-List Bid rejected by the Internal Market Monitor, a Non-Price Retirement Request may be submitted within 14 days after the resource receives notice of the rejection or 120 days prior to the date of the relevant Forward Capacity Auction, whichever is later.

III.13.1.2.3.1.5.3. Reliability Review of Non-Price Retirement Requests.

The ISO will review a Non-Price Retirement Request pursuant to Section III.13.2.5.2.5 to determine if the resource is needed for reliability. If the Non-Price Retirement Request is rejected for reliability reasons and the resource elects not to proceed with retirement as provided in Section III.13.2.5.2.5.3(a)(iii), and the resource remains in operation to meet the reliability need, the resource will be compensated pursuant to Section III.13.2.5.2.5.1(c). Upon resolution of the reliability issue, the Non-Price Retirement Request will be approved and the resource, or portion thereof, as applicable, will retire pursuant to Section III.13.1.2.3.1.5.4.

III.13.1.2.3.1.5.4. Obligation to Retire.

A Generating Capacity Resource, or portion thereof, with an approved Non-Price Retirement Request will be retired as described in Section III.13.2.5.2.5.3(a) unless, in the case of a Generating Capacity Resource that had its Non-Price Retirement Request rejected for reliability reasons, the Commission directs that the obligation to retire be removed or the retirement date extended as part of an Incremental Cost of Reliability Service filing made pursuant to Section III.13.2.5.2.5.2.

III.13.1.2.3.1.6. Static De-List Bids and Permanent De-List Bids for Existing Generating Capacity Resources at Stations having Common Costs.

Where Existing Generating Capacity Resources at a Station having Common Costs elect to submit Static De-List Bids or Permanent De-List Bids, the provisions of this Section III.13.1.2.3.1.6 shall apply.

III.13.1.2.3.1.6.1. Submission of Cost Data.

In addition to the information required elsewhere in this Section III.13.1.2.3, Static De-List Bids or Permanent De-List Bids submitted by an Existing Generating Capacity Resource that is associated with a Station having Common Costs and seeking to delist must include detailed cost data to allow the ISO to determine the Asset-Specific Going Forward Costs for each asset associated with the Station and the Station Going Forward Common Costs.

III.13.1.2.3.1.6.2. [Reserved.]

III.13.1.2.3.1.6.3. Internal Market Monitor Review.

The Internal Market Monitor will review each Static De-List Bid and Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs pursuant to the following methodology:

(i) Calculate the average Asset-Specific Going Forward Costs of each asset at the Station.

(ii) Order the assets from highest average Asset-Specific Going Forward Costs to lowest average Asset-Specific Going Forward Costs; this is the preferred de-list order.

(iii) Calculate and assign to each asset a station cost that is equal to the average cost of the assets remaining at the Station, including Station Going Forward Common Costs, assuming the successive de-listing of each individual asset in preferred de-list order.

(iv) Calculate a set of composite costs that is equal to the maximum of the cost associated with each asset as calculated in (i) and (iii) above.

The Internal Market Monitor will adjust the set of composite costs to ensure a monotonically non-increasing set of bids as follows: any asset with a composite cost that is greater than the composite cost of the asset with the lowest composite cost and that has average Asset-Specific Going Forward Costs that are less than its composite costs will have its composite cost set equal to that of the asset with the lowest composite cost. The bids of the asset with the lowest composite cost and of any assets whose composite

costs are so adjusted will be considered a single non-rationable bid for use in the Forward Capacity Auction.

The Internal Market Monitor will compare a de-list bid developed using the adjusted composite costs to the de-list bid submitted by the Existing Generating Capacity Resource that is associated with a Station having Common Costs. If the Internal Market Monitor determines that the submitted de-list bid is less than or equal to the bid developed using the adjusted composite costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines that the submitted de-list bid is greater than the bid developed using the adjusted composite costs or is not consistent with the submitted supporting cost data, then the Internal Market Monitor will reject the bid as described in Section III.13.1.2.3.2.1.1.

III.13.1.2.3.2. Review by Internal Market Monitor of Bids from Existing Generating Capacity Resources.

III.13.1.2.3.2.1. Static De-List Bids, Export Bids Above $1.00/kW-month, and Permanent De-List Bids Above $1.00/kW-month.

The Internal Market Monitor shall review each Static De-List Bid, each Export Bid above $1.00/kW-month, and each Permanent De-List Bid above $1.00/kW-month to determine whether the bid is consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward costs (as determined pursuant to Section III.13.1.2.3.2.1.1) and opportunity costs (as determined pursuant to Section III.13.1.2.3.2.1.2). Sufficient documentation and information must be included in the Existing Capacity Qualification Package to allow the Internal Market Monitor to make such determinations. Any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid shall report costs using ISO spreadsheets and forms provided, and may supplement this information with other evidence as deemed necessary. The entire de-list submittal shall be accompanied by an affidavit executed by a corporate officer attesting to the accuracy of the reported costs and the reasonableness of the estimates and adjustments of costs that would otherwise be avoided if the resource were not required to meet the obligations of a listed resource, and shall be subject to audit upon request by the ISO.

III.13.1.2.3.2.1.1. Internal Market Monitor Review of De-List Bids.

The Internal Market Monitor may seek additional information from the Lead Market Participant after the qualification deadline to address any questions or concerns regarding the data submitted, as appropriate.

III.13.1.2.3.2.1.1.1. Review of Permanent De-List Bids and Export Bids.

In the case of a Permanent De-List Bid or an Export Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). If the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.1, both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net risk- adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The Lead Market Participant for such a resource may elect to have the ISO-determined bid entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b) by so indicating in a filing with the Commission in response to the informational filing described in Section III.13.8.1(a). Such a filing, and notification to the ISO of any such election, shall be made in accordance with the terms of Section III.13.8.1(b) and shall not limit the other rights provided under that section. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. In no case shall rejection of a de-list bid by the Internal Market Monitor restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

III.13.1.2.3.2.1.1.2. Review of Static De-List Bids.

(a) In the case of a Static De-List Bid, if the Internal Market Monitor determines that the bid is consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward and opportunity costs, then the bid shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b); provided however, that no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to: (i) withdraw the Static De-List Bid entirely, in which case the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c); or (ii) submit revised prices for the Static De-List Bid for the resource at

prices equal to or less than the highest price indicated in the initial Static De-List Bid as approved by the Internal Market Monitor and greater than $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. In no case shall withdrawal of a Static De-List Bid pursuant to this subsection restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

(b) In the case of a Static De-List Bid, if the Internal Market Monitor determines, after due consideration and consultation with the Lead Market Participant, as appropriate, that the bid is not consistent with the resource's net risk-adjusted going forward and opportunity costs, then the bid will be rejected. Where a de-list bid is rejected pursuant to this Section III.13.1.2.3.2.1.1.2(b), both the qualification determination notification described in Section III.13.1.2.4 and the informational filing made to the Commission as described in Section III.13.8.1(a) shall include an explanation of the reasons that the de-list bid was rejected based on the Internal Market Monitor review and the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. In such a case, no later than 7 days after the issuance by the ISO of the qualification determination notification described in Section III.13.1.2.4, the Lead Market Participant may elect to submit revised prices for the Static De-List Bid for the resource at prices equal to or less than the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor and greater than $1.00/kW-month. Where revised prices are submitted, the Static De-List Bid must nonetheless comply with the requirements of Section III.13.1.2.3.1.1. A Lead Market Participant making such an election shall be prohibited from challenging pursuant to Section III.13.8.1(b) the Internal Market Monitor's determinations regarding the resource's net risk-adjusted going forward costs and opportunity costs. If no such election is made, the Existing Generating Capacity Resource will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c) or as otherwise directed by the Commission. If no such election is made, and the Existing Generating Capacity Resource is entered into the Forward Capacity Auction as described in Section III.13.2.3.2(c), then nothing in this subsection shall restrict the ability of the resource to dynamically de-list at prices below $1.00/kW-month.

III.13.1.2.3.2.1.2. Net Risk-Adjusted Going Forward Costs.

A Static De-List Bid, Export Bid above $1.00/kW-month, or Permanent De-List Bid above $1.00/kW-month shall be considered consistent with the Existing Generating Capacity Resource's net risk-adjusted going forward costs based on a review of the data submitted in the following formula. To the extent

possible, all costs and operational data used in this calculation shall be the cumulative actual data for the Existing Generating Capacity Resource from the most recent full Capacity Commitment Period available.

$$\frac{\left(\left[GFC / AA\right] + \left[RF\right] + \left[MR - PER\right]\right) \times InfIndex}{\left(CQ_{Summer}, kw\right) \times \left(2, months\right)}$$

Where:

GFC = annual going forward costs, in dollars. These are costs that might otherwise be avoided or not incurred if the resource were not subject to the obligations of a listed capacity resource during the Capacity Commitment Period (i.e., maintaining a constant condition of being ready to respond to commitment and dispatch orders). Costs that are not avoidable in a single Capacity Commitment Period and costs associated with the production of energy are not to be included. Service of debt is not a going forward cost. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only in the absence of a Capacity Supply Obligation may be included. Staffing, maintenance, capital expenses, and other normal expenses that would be avoided only if the resource were not participating in the energy and ancillary services markets may not be included, except in the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid). These costs shall be reported to the ISO using the spreadsheet provided on the ISO website by any Existing Generating Capacity Resource submitting a Static De-List, Permanent De-List Bid, or Export Bid, shall be accompanied by a signed affidavit, and shall be subject to audit upon request by the ISO. To the extent that the Capacity Commitment Period data used to calculate these data do not reflect known and measurable costs that would or are likely to be incurred in the relevant Capacity Commitment Period, the Internal Market Monitor shall also consider adjustments submitted, provided the costs are based on known and measurable conditions and supported by appropriate documentation to reflect those costs.

CQ_{Summer}kW = capacity seeking to de-list in kW. In no case shall this value exceed the resource's summer Qualified Capacity.

RF = risk factor, in dollars. This value shall be calculated using the following formula:

RF = [(RPC x EFORd) + (P x (Forward Capacity Auction Starting Price – AFCAP) x 12,months)] x CQ_{Summer}kW

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

RPC = replacement power costs rate, in dollars/kW. As soon as practicable, this value shall be determined by the ISO by comparing the PER Proxy Unit's daily price to the resource's Real-Time nodal price. For each hour that the resource's nodal price exceeds the PER Proxy Unit's daily price, the RPC rate for that hour will be the difference between the nodal price and the PER Proxy Unit's daily price. For each Capacity Commitment Period, the annual RPC rate will then be the sum of all hourly RPC values. The RPC rate used in the RF equation shall then be the average of the annual RPC rates for the three most recent Capacity Commitment Periods. The Lead Market Participant may specify two of the three years to be averaged. Upon exercising such option, the RPC value used shall be an average of the RPC values for the two years selected, provided however that if the Lead Market Participant selects two of three years for the PER values, the same years must be selected for the PER values for both calculations.

P = Probability estimate of a significant decrease in capacity as specified in Section III.13.4.2.1.3 occurring after the de-list bid submittal deadline and before the last annual reconfiguration auction prior to the Capacity Commitment Period. This estimate shall be no greater than the EFORd of the resource for the corresponding period used in quantifying going forward costs, and in no case greater than 0.40. The Lead Market Participant is required to provide an explanation of the derivation of the probability estimate.

AFCAP = Average FCA Price, in $/kWmo. This value shall be the average of the last three Forward Capacity Auction clearing prices in the resource's Capacity Zone.

AA = availability adjustment. AA = (1 – EFORd)

Provided: If EFORd is greater than 0.40 then 0.40 shall be used, and if EFORd is less than 0.05 then 0.05 shall be used.

EFORd shall be for the corresponding period used in quantifying going forward costs and shall be calculated using reported availability data (GADS) for the Existing Generating Capacity Resource.

IMR = annual infra-marginal rents, in dollars. In the case of a resource that has indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period (and thereafter, in the case of a Permanent De-List Bid),this value shall be calculated by subtracting all submitted cost data representing the cumulative actual cost of production (total expenses related to the production of energy, e.g. fuel, actual consumables such as chemicals and water, and, if quantified, incremental labor and maintenance) from the Existing Generating Capacity Resource's total ISO market revenues. In the case of a resource that has not indicated in the submission of a Static De-List Bid or Permanent De-List Bid that the resource will not be participating in the energy and ancillary services markets during the Capacity Commitment Period, this value shall be $0.00. As soon as practicable, the resource's total ISO market revenues used in this calculation shall be calculated by the ISO and available to the Lead Market Participant upon request.

PER = resource-specific annual peak energy rents, in dollars. As soon as practicable, this value shall be calculated by the ISO and available to the Lead Market Participant upon request.

At the option of the Lead Market Participant, the cumulative production costs for each of the most recent three Capacity Commitment Periods may be submitted and the annual infra-marginal rents calculated for each year. The Lead Market Participant may then specify two of the three years to be averaged and subsequently used as the IMR value. Upon exercising such option, the PER value used shall be an average of the PER values for the two years selected

InfIndex = inflation index. infIndex = $(1 + i)^4$

Where: "*i*" is the most recent reported 1-Year Constant Maturity Treasury Rate at the beginning of the qualification period. The specific value to be used shall be specified by the ISO and available to the Lead Market Participant.

III.13.1.2.3.2.1.3. Opportunity Costs.

To the extent that an Existing Generating Capacity Resource submitting a Static De-List Bid, Export Bid above $1.00/kW-month, or Permanent De-List Bid above $1.00/kW-month has opportunity costs that support a de-list or export bid that exceeds the thresholds described in Section III.13.1.2.3.1, the Lead Market Participant must include in the Existing Capacity Qualification Package evidence supporting such costs. Any risk that can be quantified and analytically supported and that is not already reflected in the formula for net risk-adjusted going forward costs described in Section III.13.1.2.3.2.1.2 may be included as an opportunity cost. Opportunity costs associated with major repairs necessary to restore decreases in capacity as described in Section III.13.1.2.2.4, capital projects required to operate the plant as a capacity resource or other uses of the resource shall be considered, provided such costs are substantiated by evidence of a repair plan, documented business plan and fundamental market analysis, or other independent and transparent trading index or indices as applicable. Substantiation of opportunity costs relying on sales in reconfiguration auctions or risk aversion premiums shall not be considered sufficient justification. The ISO will consider evidence of opportunity costs described in this Section III.13.1.2.3.2.1.3, and if the ISO determines that the opportunity costs justify a de-list bid or export bid above the threshold described in Section III.13.1.2.3.1, the bid will be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b).

III.13.1.2.3.2.2. [Reserved.]

III.13.1.2.3.2.3. Administrative Export De-List Bids.

The Internal Market Monitor shall review each Administrative Export De-List Bid associated with a multi-year contract entered into prior to April 30, 2007 in the first Forward Capacity Auction in which it clears. An Administrative Export De-List Bid shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.2.3.2.4. Static De-List Bids for Reductions in Ratings Due to Ambient Air Conditions.

A Lead Market Participant may submit a Static De-List Bid for up to the megawatt amount that the Lead Market Participant expects will not be physically available due to the difference between the summer Qualified Capacity at 90 degrees and the expected rating of the resource at 100 degrees. The ISO shall

verify during the qualification process that the rating is accurate. Such Static De-List Bids may be entered into the Forward Capacity Market at prices up to and including the Forward Capacity Auction Starting Price, subject to validation of the physical limit. Static De-List Bids for reductions in ratings due to ambient air conditions shall not be subject to the review described in Section III.13.1.2.3.2 and need not include documentation for that purpose.

III.13.1.2.3.2.5. Incremental Capital Expenditure Recovery Schedule.

Except as described below, the Internal Market Monitor shall review all de-list bids using the following cost recovery schedule for incremental capital expenditures, which assumes an annual pre-tax weighted average cost of capital of 10 percent.

Age of Existing Resource (years)	Remaining Life (years)	Annual Rate of Capital Cost Recovery
1 to 5	30	0.106
6 to 10	25	0.110
11 to 15	20	0.117
16 to 20	15	0.131
21 to 25	10	0.163
25 plus	5	0.264

A Market Participant may request that a different pre-tax weighted average cost of capital be used to determine the resource's annual rate of capital cost recovery by submitting the request, along with supporting documentation, in the Existing Capacity Qualification Package. The Internal Market Monitor shall review the request and supporting documentation and may, at its sole discretion, replace the annual rate of capital cost recovery from the table above with a resource-specific value based on an adjusted pre-tax weighted average cost of capital. If the Internal Market Monitor uses an adjusted pre-tax weighted average cost of capital for the resource, then the resource's annual rate of capital cost recovery will be determined according to the following formula:

$$\frac{CostOfCapital}{(1-(1+CostOfCapital)^{-RemainingLife})}$$

Where:

Cost Of Capital = the adjusted pre-tax weighted average cost of capital.

Remaining Life = the remaining life of the existing resource, based on the age of the resource, as indicated in the table above.

III.13.1.2.4. Qualification Determination Notification for Existing Capacity.

No later than 127 days before the Forward Capacity Auction, the ISO shall send notification to the Lead Market Participant that submitted each Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid indicating whether the bid has been accepted for participation in the Forward Capacity Auction. Each accepted Static De-List Bid, Permanent De-List Bid, Export Bid, and Administrative Export De-List Bid shall be binding and shall be entered into the Forward Capacity Auction as described in Section III.13.2.3.2(b). Where a Static De-List Bid, Permanent De-List Bid, Export Bid, or Administrative Export De-List Bid is not accepted for participation in the Forward Capacity Auction as a result of the Internal Market Monitor's review pursuant to Section III.13.1.2.3.2, the notification shall include an explanation of the reasons the Existing Capacity Qualification Package was not accepted and shall include the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The qualification determination shall not include the results of the reliability review subject to Section III.13.2.5.2.5.

III.13.1.2.5. Optional Existing Capacity Qualification Package for New Generating Capacity Resources Previously Counted as Capacity.

A resource seeking to participate in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) may elect to submit an Existing Capacity Qualification Package in addition to the New Capacity Show of Interest Form and New Capacity Qualification Package that it is required to submit pursuant to Section III.13.1.1.2. The bids contained in an Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must clearly indicate which New Generating Capacity Resource the Existing Capacity Qualification Package is associated with, and if accepted in accordance with Section III.13.1.2.3, would only be entered into the Forward Capacity Auction where: (i) the new resource is not accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.2; or (ii) no offer from that New Generating Capacity Resource clears in the Forward Capacity Auction, as described in Section III.13.2.3.2(e). An Existing Capacity Qualification Package submitted pursuant to this Section III.13.1.2.5 must conform in all other respects to the requirements of this Section III.13.1.2.

III.13.1.3. Import Capacity.

The qualification requirements for import capacity shall depend on whether the import capacity is an Existing Import Capacity Resource or a New Import Capacity Resource. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction shall have a Capacity Supply Obligation and shall receive payments only for the one-year Capacity Commitment Period associated with that Forward Capacity Auction. Both Existing Import Capacity Resources and New Import Capacity Resources clearing in the Forward Capacity Auction must be backed by one or more External Resources or by an external Control Area throughout the relevant Capacity Commitment Period. An external Demand Resource may not be an Existing Import Capacity Resource or a

New Import Capacity Resource. External nodes shall be mapped to Capacity Zones as shown in the following table:

External Node Common Name	Capacity Zone
NB-NE External Node	**Maine**
HQ Phase I/II External Node	**Rest-of-Pool**
Highgate External Node	**Rest-of-Pool**
NY-NE AC External Node	**Rest-of-Pool**
Cross Sound Cable External Node	**CT**

III.13.1.3.1. Definition of Existing Import Capacity Resource.

Capacity associated with a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, shall participate in the Forward Capacity Auction as an Existing Import Capacity Resource, except that if that Existing Import Capacity Resource has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.2. Qualified Capacity for Existing Import Capacity Resources.

The summer Qualified Capacity and winter Qualified Capacity of an Existing Import Capacity Resource shall be based on the data provided to the ISO during the qualification process, subject to ISO review and verification.

The qualified capacity for the Existing Import Capacity Resources associated with the VJO and NYPA contracts listed in Section III.13.1.3.3(c) as of the Capacity Commitment Period beginning June 1, 2014 shall be equal to the lesser of the stated amount in Section III.13.1.3.3(c) or the median amount of the energy delivered from the Existing Import Capacity Resource during the New England system coincident peak over the previous five Capacity Commitment Periods at the time of qualification.

III.13.1.3.3. Qualification Process for Existing Import Capacity Resources.

Existing Import Capacity Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3, except as follows:

(a) No later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting each Existing Import Capacity Resource must also submit to the ISO: (i) documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import. In either case, the Market Participant must specify the interface over which the capacity will be imported.

(b) The rationing election described in Section III.13.1.2.3.1 shall not apply. An Existing Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, Existing Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

(c) The Existing Import Capacity Resources associated with contracts listed in the table below may qualify to receive the treatment described in Section III.13.2.7.3 for the duration of the contracts as listed. For each Forward Capacity Auction after the first Forward Capacity Auction, in order for an Existing Import Capacity Resource associated with a contract listed below to qualify for the treatment described in Section III.13.2.7.3, no later than 10 Business Days prior to the Existing Capacity Qualification Deadline, the Market Participant submitting the Existing Import Capacity Resource must also submit to the ISO

documentation verifying that the contract will remain in effect throughout the Capacity Commitment Period and that it has not been amended. For the first Forward Capacity Auction, Existing Import Capacity Resources associated with contracts listed in the table below are qualified to receive the treatment described in Section III.13.2.7.3.

Contract Description	**MW**	**Contract End Date**
NYPA: NY ─ NE: CMEEC	13.2	8/31/2025
NYPA: NY ─ NE: MMWEC	53.3	8/31/2025
NYPA: NY ─ NE: Pascoag	2.3	8/31/2025
NYPA: NY─ NE: VELCO	15.3	8/31/2025
	84.1	
VJO: Highgate ─ NE	Up to 225	10/31/2016
VJO: Highgate ─ NE (extension) (beginning 11/01/2016)	Up to 6	October 2020
VJO: Phase I/II ─ NE	Up to 110	10/31/2016

III.13.1.3.4. Definition of New Import Capacity Resource.

Capacity not associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for the whole Capacity Commitment Period, but that meets the requirements of Section III.13.1.3.5.1, shall participate in the Forward Capacity Auction as a New Import Capacity Resource. For capacity associated with a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, or capacity from an External Resource that is owned or directly controlled by the Lead Market Participant and which is committed for at least two whole consecutive Capacity Commitment Periods by the Lead Market Participant in the New Capacity Qualification Package, if the import capacity has not cleared in a previous Forward Capacity Auction, then the import capacity shall participate in the Forward Capacity Auction as a New Import Capacity Resource.

III.13.1.3.5. Qualification Process for New Import Capacity Resources.

The qualification process for a New Import Capacity Resource, whether backed by a new External Resource, by one or more existing External Resources, or by an external Control Area, shall be the same

as the qualification process for a New Generating Capacity Resource, as described in Section III.13.1.1.2, except as follows:

III.13.1.3.5.1. Documentation of Import.

For each New Import Capacity Resource, the Market Participant submitting the import capacity must also submit: (i) documentation of a one-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for the entire Capacity Commitment Period, including documentation of the MW value of the contract; (ii) documentation of a multi-year contract entered into before the New Capacity Qualification Deadline to provide capacity in the New England Control Area from outside of the New England Control Area for a period including the entire Capacity Commitment Period if the import capacity has not cleared in a previous Forward Capacity Auction, including documentation of the MW value of the contract; (iii) proof of ownership or direct control over one or more External Resources that will be used to back the New Import Capacity Resource during the Capacity Commitment Period, including information to establish the summer and winter ratings of the resource(s) backing the import; or (iv) documentation for system-backed import capacity that the import capacity will be supported by the Control Area and that the energy associated with that system-backed import capacity will be afforded the same curtailment priority as that Control Area's native load. For each New Import Capacity Resource, the Market Participant must specify the interface over which the capacity will be imported. The Market Participant must indicate whether the import is associated with any investment in transmission that increases New England's import capability. If the import will be backed by a single new External Resource, the Market Participant submitting the import capacity must also submit a general description of the project's equipment configuration, including a description of the resource type (such as those listed in the table in Section III.A.21.1 or some other type).

III.13.1.3.5.2. Import Backed by Existing External Resources.

If the New Import Capacity Resource will be backed by one or more External Resources existing at the time of the Forward Capacity Auction, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit a description of how the Capacity Supply Obligation, if an offer from the New Import Capacity Resource clears in the Forward Capacity Auction, will be met.

The description must indicate specifically which External Resources will back the New Import Capacity Resource during the Capacity Commitment Period, and if those External Resources are not owned or

controlled directly by the Market Participant, the description must include a commitment that the External Resources will have sufficient capacity that is not obligated outside the New England Control Area to fully satisfy the New Import Capacity Resource's potential Capacity Supply Obligation during the Capacity Commitment Period and demonstrate how that commitment will be met.

III.13.1.3.5.3. Imports Backed by an External Control Area.

If the New Import Capacity Resource will be backed by an external Control Area, the provisions regarding site control (Section III.13.1.1.2.2.1) and critical path schedule (Section III.13.1.1.2.2.2) shall not apply, and the Market Participant shall instead submit system load and capacity projections for the external Control Area showing sufficient excess capacity during the Capacity Commitment Period to back the New Import Capacity Resource.

III.13.1.3.5.3.1. Imports Crossing Intervening Control Areas.

The preceding rules define requirements associated with the import of capacity from a Control Area, or resources located in a Control Area, directly adjacent to the New England Control Area. Imports of capacity from a Control Area or resources located in a Control Area where such import crosses an intervening Control Area or Control Areas shall comply with the following additional requirements: (1) For imports crossing a single intervening Control Area, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, that the remote Control Area will afford the energy export to the adjacent intervening Control Area the same curtailment priority as its native load, that the adjacent intervening Control Area has procedures in place to explicitly recognize the linkage between the import and re-export of energy in support of the import contract, and that the energy export to the ISO will not be curtailed (except pro-rata with a curtailment of native load) so long as the linked import is flowing. (2) For imports crossing more than one intervening Control Area, in addition to the requirements above, the Market Participant entering the import contract shall demonstrate, as detailed in the ISO New England Manuals, by the New Capacity Qualification Deadline, that explicit market and operating procedures exist among the intervening Control Areas to ensure that the energy required to be delivered to the New England Control Area will be guaranteed the same curtailment priority as the intervening native loads, and that none of the intervening Control Areas will curtail the transaction except in conjunction with a curtailment of native load. (3) The Market Participant entering the import contract shall demonstrate that capacity it supplies to the New England Control Area will not be recalled or curtailed to satisfy the load of the external Control Area, or that the external Control Area in which it is located will afford New England Control Area load the same curtailment priority that it affords its own Control Area native load.

III.13.1.3.5.4. Capacity Commitment Period Election.

The provisions regarding Capacity Commitment Period election (Section III.13.1.1.2.2.4) shall not apply. A New Import Capacity Resource may not elect to have the Capacity Supply Obligation and the Capacity Clearing Price applicable to an offer that clears in the Forward Capacity Auction continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears.

III.13.1.3.5.5. Initial Interconnection Analysis.

The provisions regarding initial interconnection analysis (Section III.13.1.1.2.3) shall not apply.

III.13.1.3.5.6. Review by Internal Market Monitor of Offers from New Import Capacity Resources and Existing Import Capacity Resources.

In addition to the review described in Section III.13.1.1.2.2.3 and Section III.A.21, the Internal Market Monitor shall review each offer from Existing Import Capacity Resources and New Import Capacity Resources. An offer from an Existing Import Capacity Resource or a New Import Capacity Resource shall be rejected if the Internal Market Monitor determines that the bid may be an attempt to manipulate the Forward Capacity Auction, and the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)).

III.13.1.3.5.7. Qualification Determination Notification for New Import Capacity Resources.

For New Import Capacity Resources, the qualification determination notification described in Section III.13.1.1.2.8 shall be modified to reflect the differences in the qualification process described in this Section III.13.1.3.5.

III.13.1.3.5.8. Rationing Election.

The rationing election described in Section III.13.1.1.2.2.3(b) shall not apply. A New Import Capacity Resource may not elect whether to be rationed. As described in Section III.13.2.6, New Import Capacity Resources are always subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface.

III.13.1.4. Demand Resources.

III.13.1.4.1. Demand Resources.

To participate in a Forward Capacity Auction as a Demand Resource, a resource must meet the requirements of this Section III.13.1.4.1. No resource shall be permitted to participate in a Forward Capacity Auction as a Demand Response Capacity Resource prior to the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. A Demand Response Capacity Resource with an early Commercial Operation Date shall be considered a Real-Time Demand Response Resource for any Capacity Commitment Period commencing prior to June 1, 2017. No resource shall be permitted to participate in a Forward Capacity Auction as a Real-Time Demand Response Resource beginning with the Forward Capacity Auction for the 2017-2018 Capacity Commitment Period. The amount of capacity offered by a Demand Resource shall be a minimum of 100 kW aggregated in a Dispatch Zone. A Demand Resource may continue to offer capacity into Forward Capacity Auctions and reconfiguration auctions for Capacity Commitment Periods in an amount less than or equal to its remaining Measure Life. Demand Resources must comply with all applicable federal, state, and local regulatory, siting, and tariff requirements, including interconnection tariff requirements related to siting, interconnection, and operation of the Demand Resource. Demand Resources are not permitted to submit import or export bids or Administrative Export De-list Bids.

A Demand Resource shall no longer be eligible to participate in the Forward Capacity Market if its Permanent De-list Bid is accepted. For purposes of this Section III.13.1.4, references to the Lead Market Participant for a resource shall include the Enrolling Participant for a Demand Resource.

III.13.1.4.1.1. Existing Demand Resources.

Demand Resources that previously have been in service and registered with the ISO, and which are not otherwise New Demand Resources, shall be Existing Demand Resources. Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, or (ii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of this Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction. Except as specified in Section III.13.1.4.1, Existing Demand Resources shall be subject to the same qualification process as Existing Generating Capacity Resources, as described in Section III.13.1.2.3. Existing Demand Resources shall be subject to Section III.13.1.2.2.5.2. An Existing Demand Resource may submit a Non-Price Retirement Request pursuant to the provisions of Section III.13.1.2.3.1.5, provided, however, that Non-Price Retirement Requests shall not be used as a mechanism to inappropriately qualify assets

associated with Existing Demand Resources as New Demand Resources. Existing Demand Resources may de-list consistent with Sections III.13.1.2.3.1.1 and III.13.1.2.3.1.2. Existing Demand Response Capacity Resources shall be subject to Section III.13.7.1.1.5.

III.13.1.4.1.2. New Demand Resources.

A New Demand Resource is a Demand Resource that has not been in service prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, or Distributed Generation that has operated only to address an electric power outage due to failure of the electrical supply, on-site disaster, local equipment failure, or public service emergencies such as flood, fire, or natural disaster, or excessive deviations from standard voltage from the electrical supplier to the premises during the 12-month period prior to the applicable Existing Capacity Qualification Deadline of the Forward Capacity Auction, and is not an Existing Demand Resource. A Demand Resource that has previously been defined as an Existing Demand Resource shall be considered a New Demand Resource if it meets one of the conditions listed in Section III.13.1.1.1.2.

III.13.1.4.1.2.1. Qualified Capacity of New Demand Resources.

For Forward Capacity Auctions a New Demand Resource shall have a summer Qualified Capacity and winter Qualified Capacity based on the resource's Demand Reduction Values as submitted and reviewed pursuant to this Section III.13.1.4.

The documentation, analysis, studies and methodologies used to support the estimates described in this Section III.13.1.4.1.2.1 must be submitted as part of the Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.1.2.2. Initial Analysis for Certain New Demand Resources

For each New Demand Resource that is a Demand Response Capacity Resource, Real-Time Demand Response Resource or a Real-Time Emergency Generation Resource, the ISO shall perform an analysis based on the information provided in the New Demand Resource Show of Interest Form to determine the amount of capacity that the resource could provide by the start of the associated Capacity Commitment Period. This analysis shall be performed consistent with the criteria and conditions described in ISO New England Planning Procedures. Where, as a result of this analysis, the ISO determines that because of overlapping interconnection impacts, such a New Demand Resource that is otherwise accepted for participation in the Forward Capacity Auction in accordance with the other provisions and requirements

of this Section III.13.1 cannot deliver any of the capacity that it would otherwise be able to provide (in the absence of the other relevant Existing Capacity Resources), then that New Demand Resource will not be accepted for participation in the Forward Capacity Auction.

III.13.1.4.1.3. Special Provisions for Real-Time Emergency Generation Resources.

All Real-Time Emergency Generation Resources shall be treated in the same manner as Existing Demand Resources in the Forward Capacity Auction as described in Section III.13.2. Real-Time Emergency Generation Resources may: (i) submit Static De-list Bids pursuant to Section III.13.1.2.3.1.1, (ii) submit Dynamic De-list Bids pursuant to Section III.13.2.3.2(d), or (iii) submit Permanent De-list Bids pursuant to Section III.13.1.2.3.1.2. Real-Time Emergency Generation Resources may not submit an Export Bid pursuant to Section III.13.1.2.3.1.3 or an Administrative Export De-list Bid pursuant to Section III.13.1.2.3.1.4. Real-Time Emergency Generation Resources may not import capacity pursuant to Section III.13.1.3. A Real-Time Emergency Generation Resource may not participate in a reconfiguration auction. Such resources may participate in a Capacity Supply Obligation Bilateral as either a Capacity Transferring Resource or a Capacity Acquiring Resource, provided, however, that where a Real-Time Emergency Generation Resource participates in a Capacity Supply Obligation Bilateral as a Capacity Acquiring Resource, the Capacity Transferring Resource must also be a Real-Time Emergency Generation Resource. Such resources may not be Supplemental Capacity Resources. Real-Time Emergency Generation Resources that are New Demand Resources as defined in Section III.13.1.4.1.2 shall be subject to the qualification and financial assurance requirements applicable to New Demand Resources.

III.13.1.4.2. Show of Interest Form for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit to the ISO a New Demand Resource Show of Interest Form as described in this Section III.13.1.4.2 during the New Capacity Show of Interest Submission Window, as described in Section III.13.1.10. The ISO may waive the submission of any information not required for evaluation of a project. The New Demand Resource Show of Interest Form is available on the ISO website.

(a) A completed New Demand Resource Show of Interest Form shall include, but is not limited to, the following information: project name; Load Zone within which the Demand Resource project will be located; the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource will be located; estimated summer

and winter Demand Reduction Values (MW) per measure and/or per customer facility (measured at the customer meter and not including losses) expected to be achieved five weeks prior to the first and second annual Forward Capacity Auctions after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award would be made, if applicable, and on the Commercial Operation date; estimated total summer and winter Demand Reduction Value of the Demand Resource project; supporting documentation (e.g., engineering estimates or documentation of verified savings from comparable projects) to substantiate the reasonableness of the estimated Demand Reduction Values; Demand Resource type (On-Peak Demand Resource, Seasonal Peak Demand Resource, Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource); brief Demand Resource project description including measure type (i.e., Energy Efficiency, Load Management, and/or Distributed Generation); types of facilities at which the measures will be implemented; customer classes and end-uses served; expected Commercial Operation date – i.e., the date by which the Project Sponsor expects to reach Commercial Operation (Commercial Operation for a Demand Resource shall mean the demonstration to the ISO by the Project Sponsor that the Demand Resource described in the Project Sponsor's New Demand Resource Qualification Package has achieved its full Demand Reduction Value); ISO Market Participant status and ISO customer identification (if applicable); status under Schedules 22 or 23 of the Transmission, Markets and Services Tariff (if applicable); project/technical and credit/financial contacts; and for individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value equal to or greater than 5 MW, the Pnode and service address at which the end-use facility is located; capability and experience of the Project Sponsor.

III.13.1.4.2.1. Qualification Package for Existing Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as an Existing Demand Resource, the Project Sponsor must submit an Existing Capacity Qualification Package no later than the Existing Capacity Qualification Deadline. The Existing Capacity Qualification Package for an Existing Demand Resource shall conform to the requirements of Section III.13.1.4.1. All Existing Demand Resources must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.2. Qualification Package for New Demand Resources.

For each resource that a Project Sponsor seeks to offer in the Forward Capacity Auction as a New Demand Resource, the Project Sponsor must submit a New Demand Resource Qualification Package no

later than the New Capacity Qualification Deadline. The New Demand Resource Qualification Package shall conform to the requirements of this Section III.13.1.4.2.2. The ISO may waive the submission of any information not required for evaluation of a project.

III.13.1.4.2.2.1. [Reserved.]

III.13.1.4.2.2.2. Source of Funding.

The Project Sponsor must provide source of funding which includes, but is not limited to, the following information: The source(s) of public benefits funding or private financing, or a funding plan supplemented by information on how previous projects were funded; A completed ISO credit application.

III.13.1.4.2.2.3. Measurement and Verification Plan.

For all Demand Resources other than Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Project Sponsor must provide a Measurement and Verification Plan which complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3, Section III.8A and III.8B and the ISO New England Manuals.

III.13.1.4.2.2.4. Customer Acquisition Plan.

A Project Sponsor with more than a single customer must provide a description of its plan to acquire customers that includes, but is not limited to, the following information: a description of proposed customer market; the estimated size of target market and supporting documentation; a marketing plan with supporting documentation describing the manner in which customers will be recruited; and evidence supporting the viability of the marketing plan.

III.13.1.4.2.2.4.1. Individual Distributed Generation Projects and Demand Resource Projects From a Single Facility With A Demand Reduction Value Greater Than or Equal to 5 MW.

For individual Distributed Generation projects and Demand Resource projects from a single facility with a Demand Reduction Value greater than or equal to 5 MW the critical path schedule requirements and the monitoring and milestones are the same as those required for New Generating Capacity Resources as set forth in Section III.13.1.1.2.2.2.

III.13.1.4.2.2.4.2. Demand Resource Projects Involving Multiple Facilities and Demand Resource Projects From a Single Facility With A Demand Reduction Value Less Than 5 MW.

A critical path schedule for Demand Resource projects installed at multiple facilities and Demand Resource projects from a single facility with a Demand Reduction Value of less than 5 MW shall be comprised of a delivery schedule of the share of total offered Demand Reduction Value achieved as of target dates which are: (i) The cumulative percentage of total Demand Reduction Value achieved on target date 1 occurring five weeks prior to the first annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; (ii) The cumulative percentage of total Demand Reduction Value achieved on target date 2 occurring five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the Demand Resource Project Sponsor's capacity award was made; and (iii) target date 3 which is the expected Commercial Operation date, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100% of total Demand Reduction Value must be complete

III.13.1.4.2.2.4.3. Additional Requirement For Demand Resource Project Sponsor Proposing Total Demand Reduction Value of 30 Percent or Less by the Second Target Date.

If a Demand Resource Project Sponsor proposes in its New Demand Resource Qualification Package a cumulative Percent of Total Demand Reduction Value Complete that is 30 percent or less by the second critical path schedule target date, then a pipeline analysis must be submitted to the ISO five weeks prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which the award was made. A pipeline analysis demonstrates the Demand Resource Project Sponsor's ability to fulfill its obligation to deliver capacity that cleared in a Forward Capacity Auction by the relevant Capacity Commitment Period. Such an analysis must list the customers that have made a commitment to participate in the Demand Resource Project Sponsor's program to deliver capacity to meet the Demand Resource Project Sponsor's Forward Capacity Auction obligations, and must include each customer's projected summer and winter Demand Reduction Values, and expected measure installation date; provided, however, that a Demand Resource Project Sponsor targeting customer facilities with under 10 kW of Demand Reduction Value per facility shall have the option of using a targeting and marketing plan based on past performance in that market to determine the Project Sponsor's ability to fulfill its obligation by the relevant Capacity Commitment Period. To the extent that the Demand Resource Project Sponsor is unable to demonstrate through its pipeline analysis that it has sufficient customers to meet its Capacity Supply Obligation by the beginning of the relevant Capacity Commitment Period, the Demand Resource

Project Sponsor shall be subject to the ISO's critical path schedule monitoring procedures, as specified in Section III.13.3 of Market Rule 1.

III.13.1.4.2.2.5. Capacity Commitment Period Election.

In the New Demand Resource Qualification Package, the Project Sponsor must specify whether, if its New Demand Resource offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to four additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. If no such election is made in the New Demand Resource Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Demand Resource offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Demand Resource offer clears. If the Project Sponsor elects to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, then the Project Sponsor may not change the Demand Resource type as long as that Capacity Supply Obligation and Capacity Clearing Price continue to apply. If an offer from a New Demand Resource clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.4.2.2.5.

III.13.1.4.2.2.6. Rationing Election.

The Project Sponsor for a New Demand Resource must indicate in the New Demand Resource Qualification Package if an offer from the New Demand Resource may be rationed. A Project Sponsor may specify a single MW quantity to which offers may be rationed. Without such indication, offers will only be accepted or rejected in whole. This rationing election shall apply for the entire Forward Capacity Auction.

III.13.1.4.2.3. Consistency of the New Demand Resource Qualification Package and New Demand Resource Show of Interest Form.

The ISO shall review the Project Sponsor's New Demand Resource Qualification Package for consistency with its New Demand Resource Show of Interest Form. The New Demand Resource Qualification Package may not contain material changes relative to the New Demand Resource Show of Interest Form.

A material change may include, but is not limited to the following: (i) a change in the designation of the Demand Resource type; (ii) a change in the Project Sponsor, subject to review by the ISO of the capability and experience of the new Project Sponsor; (iii) a change in the Load Zone within which the project is located, and a change in the Dispatch Zone within which the Demand Response Capacity Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource is located; (iv) a change in the total summer or winter Demand Reduction Value of the project by more than 30 percent; (v) a change in the general type of measure being implemented (e.g., Energy Efficiency, Load Management, Distributed Generation); (vi) a change in the treatment as an Existing Demand Resource for the first Forward Capacity Auction; or (viii) a misrepresentation of the interconnection status of a Distributed Generation project.

III.13.1.4.2.4. Offers From New Demand Resources.

All New Demand Resources that might submit offers in the Forward Capacity Auction at prices below the relevant Offer Review Trigger Price must include in the New Demand Resource Qualification Package the lowest price at which the resource requests to offer capacity in the Forward Capacity Auction and supporting documentation justifying that price as competitive in light of the resource's costs (as described in Section III.A.21). This price is subject to review by the Internal Market Monitor pursuant to Section III.A.21.2 and must include the additional documentation described in that section.

III.13.1.4.2.5. Notification of Qualification for Demand Resources.

III.13.1.4.2.5.1. Evaluation of Demand Resource Qualification Materials.

The ISO shall review the information submitted by Existing Demand Resources and New Demand Resources and shall determine whether the information submitted complies with the requirements set forth in this Section III.13.1.4 and whether, based on the information provided, the Demand Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to consideration of, the following:

(a) whether the information submitted by Existing Demand Resources and New Demand Resources is accurate and contains all of the elements required by this Section III.13.1.4;

(b) whether the critical path schedule submitted by New Demand Resources includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule submitted by New Demand Resources are reasonable and likely to be met;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Demand Resource are satisfied; and

(e) whether the Measurement and Verification Plan complies with the ISO's measurement and verification requirements pursuant to Section III.13.1.4.3 and the ISO New England Manuals.

III.13.1.4.2.5.2. Notification of Qualification for Existing Demand Resources.

For each Existing Demand Resource, the ISO will notify the Resource's Lead Market Participant no later than 15 Business Days before the Existing Capacity Qualification Deadline of: (i) Demand Resource type; and (ii) summer and winter Demand Reduction Values and estimates of summer and winter Qualified Capacity as defined in Section III.13.1.4.3 and the Load Zone in which the Capacity Resource is located, and the Dispatch Zone within which a Demand Response Capacity Resource, Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource is located. If the Lead Market Participant believes that an ISO-determined summer Qualified Capacity or winter Qualified Capacity for an Existing Demand Resource does not accurately reflect the determination described in Section III.13.1.4.3, then the Lead Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification. If an Existing Demand Resource is not submitting a change in its Demand Resource type, a Permanent De-List Bid or Static De-List Bid for the Forward Capacity Auction, then no further submissions or actions for that resource are necessary, and the resource shall participate in the Forward Capacity Auction as described in Section III.13.2.3.2(c) with Qualified Capacity as indicated in the ISO's notification, and may not elect to have the Capacity Supply Obligation and Capacity Clearing Price apply after the Capacity Commitment Period associated with the Forward Capacity Auction. If a Market Participant believes that the Demand Reduction Value or Qualified Capacity for an Existing Demand Resource is inaccurate or wishes to change its Demand Resource type, the Market Participant must notify the ISO within 5 Business Days of receipt of the Qualified Capacity notification and submit an Updated Measurement and Verification Plan to reflect the change in its Demand Resource type, if applicable. Updated Measurement and Verification Plans must be received by the ISO no later than 5 Business Days after receipt of the Qualified Capacity notification. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3. Notification of Qualification for New Demand Resources.

No later than 127 days prior to the relevant Forward Capacity Auction, the ISO shall send notification to Project Sponsors for each New Demand Resource indicating whether the New Demand Resource has been accepted for participation in the Forward Capacity Auction.

III.13.1.4.2.5.3.1. Notification of Acceptance to Qualify of a New Demand Resource.

For a New Demand Resource accepted for participation in the Forward Capacity Auction, the notification will specify the Demand Resource's summer and winter Demand Reduction Value and summer and winter Qualified Capacity. Designation of the Demand Resource type may not be changed during the Capacity Commitment Period.

III.13.1.4.2.5.3.2. Notification of Failure to Qualify of a New Demand Resource.

For a New Demand Resource not accepted for participation in the Forward Capacity Auction, the notification will provide an explanation as to why the resource did not meet the requirements set forth in this Section III.13.1.4 and was not accepted.

III.13.1.4.3. Measurement and Verification Applicable to All Demand Resources.

To demonstrate the Demand Reduction Value of a Demand Resource project, as defined in Section III.13.1.4.1, all Demand Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions shall submit to the ISO the Demand Resource project Measurement and Verification Documents in accordance with this Section III.13.1.4.3, Sections III.8A and III.8B and the ISO New England Manuals. Demand Response Capacity Resources and Real-Time Emergency Generation Resources participating in the Forward Capacity Auction, Capacity Supply Obligation Bilaterals or reconfiguration auctions must estimate Demand Reduction Values pursuant to the requirements of Sections III.8A, Section III.8B, Section III.13.6.1.5.4, and Section III.E1 and Section III.E2. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. A Net Supply Generator Asset or other Generator Asset located at the same Retail Delivery Point as a Demand Response Asset that is associated with a Demand Response Capacity Resource may not participate in the Forward Capacity Market as a Generating Capacity Resource, provided that this exclusion shall not apply to a Generator Asset if it is separately metered and its output is added to the metered load as measured at the Retail Delivery Point. The ISO shall review such Measurement and Verification Documents to determine whether they are consistent with the measurement and verification requirements set forth in this Section III.13.1.4.3, Section III.8A, Section III.8B, and the ISO New England Manuals.

III.13.1.4.3.1. Measurement and Verification Documents Applicable to On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Measurement and Verification Documents for On-Peak Demand Resources, and Seasonal Peak Demand Resources must demonstrate both availability and performance of Demand Resource projects in reducing demand coincident with Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours such that the reported monthly Demand Reduction Value shall achieve at least a ten percent relative precision and an eighty percent confidence interval as described and applied in the ISO New England Manual on Measurement and Verification of Demand Reduction Value from Demand Resources. The Measurement and Verification Documents shall serve as the basis for the claimed Demand Reduction Value of a Demand Resource project. The Measurement and Verification Documents shall document the measurement and verification performed to verify the achieved Demand Reduction Value of the Demand Resource project. The Measurement and Verification Documents shall contain a projection of the Demand Resource project's Demand Reduction Value for each month of the Capacity Commitment Period and over the expected Measure Life of the Demand Resource project. A Demand Resource's Measurement and Verification Documents must describe the methodology used to calculate electrical energy load reduction or output during Demand Resource On-Peak Hours, or Demand Resource Seasonal Peak Hours. The Measurement and Verification Documents shall include a Measurement and Verification Plan submitted in the Forward Capacity Auction Qualification, as described in Section III.13.1.4.3 and a monthly Measurement and Verification Summary Report during the Capacity Commitment Period. The monthly Measurement and Verification Summary Reports shall reference the measurement and verification protocols and performance data documented in the Measurement and Verification Plan or the Measurement and Verification Reference Report(s). Such monthly Measurement and Verification Summary Reports will document the Demand Resource Project Sponsor's total Demand Reduction Value from eligible pre-existing measures and new measures, and the Project Sponsor's total Demand Reduction Value from both eligible pre-existing measures and new measures, for all measures it had in operation as of the end of the previous month. The monthly Measurement and Verification Summary Reports shall be based on Measurement and Verification Documents determined in accordance with Market Rule 1 and the ISO New England Manuals, and shall be the basis for monthly settlement with Demand Resource Project Sponsors. All Measurement and Verification Documents shall conform to the ISO's specifications with respect to content, format and delivery methodology, and shall be submitted in accordance with the timelines and deadlines set forth in Market Rule 1 and the ISO New England Manuals.

III.13.1.4.3.1.1. Optional Measurement and Verification Reference Reports.

At the option of the Demand Resource Project Sponsor, the Measurement and Verification Documents may also include one or more Measurement and Verification Reference Report(s) submitted 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 shall update the prospective Demand Reduction Value of the Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

III.13.1.4.3.1.2. Updated Measurement and Verification Documents.

At the option of the Demand Resource Project Sponsor, an Updated Measurement and Verification Plan may be submitted during a subsequent Forward Capacity Auction qualification process prior to the beginning of the Capacity Commitment Period of the Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource project specifications, measurement and verification protocols, and performance data. However, the Updated Measurement and Verification Plan shall not modify for the duration of the Capacity Commitment Period the total Demand Reduction Value and the Demand Resource type from the applicable Forward Capacity Auction in which the Demand Resource Project Sponsor's offer cleared. Additionally, the Updated Measurement and Verification Plan shall provide measurement and verification consistent with the requirements specified in the ISO New England Manuals, and shall be comparable to the quality of the original Measurement and Verification Plan accepted during the Forward Capacity Auction qualification process in which the Demand Resource project cleared the Forward Capacity Auction.

III.13.1.4.3.1.3. Annual Certification of Accuracy of Measurement and Verification Documents.

Demand Resource Project Sponsors for On-Peak Demand Resources, or Seasonal Peak Demand Resources and Real-Time Demand Response Resources shall submit no less frequently than once per year, a statement certifying that the Demand Resource projects for which the Project Sponsor is requesting compensation continue to perform in accordance with the submitted Measurement and Verification Documents reviewed by the ISO. One such statement must be received by the ISO no later than 10 Business Days before the Existing Capacity Qualification Deadline.

III.13.1.4.3.1.4. Record Requirement of Retail Customers Served.

For Demand Resource projects targeting customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, Demand Resource Project Sponsors shall maintain records of retail customers served including, at a minimum, the retail customer's address, the customer's utility distribution company, utility distribution company account identifier, measures installed, and corresponding monthly Demand Reduction Values. For Demand Resource projects targeting customer facilities with under 10 kW of Demand Reduction Value per facility, the Demand Resource Project Sponsor shall maintain records as described above for customer facilities with greater than or equal to 10 kW of Demand Reduction Value per facility, or shall maintain records of aggregated Demand Reduction Value and measures installed by Load Zone and meter domain. Demand Resource Project Sponsors shall maintain such records until the end of the Measure Life, or until the Demand Resource is permanently de-listed from the Forward Capacity Market, and shall submit such records to the ISO upon request in a readable electronic format.

III.13.1.4.3.2. Measurement and Verification Documentation of Demand Reduction Values Applicable to All Demand Resources.

The Demand Resource Project Sponsor shall designate the specific methodology used to establish Demand Reduction Values, including the specification of Demand Resource On-Peak Hours for On-Peak Demand Resources, Demand Resource Seasonal Peak Hours for Seasonal Peak Demand Resources, or Real-Time Demand Response Event Hours for Real-Time Demand Response Resources, in its Measurement and Verification Plan pursuant to Section III.13.1.4.3. For Demand Response Capacity Resources and Real-Time Emergency Generation Resources, the Demand Resource Project Sponsor shall provide an estimate of Demand Reduction Values consistent with the baseline calculation methodology in Section III.8A and Section III.8B. To the extent that a Demand Response Capacity Resource consists, in whole or in part, of assets capable of delivering Net Supply, the estimated Demand Reduction Value of a Demand Response Capacity Resource may include an estimate of Net Supply. Distributed Generation, Demand Response Capacity Resource, Real-Time Demand Response, and Real-Time Emergency Generation Resource projects must include individual metering or a metering protocol consistent with the measurement and verification requirements set forth in Market Rule 1 and the ISO New England Manuals to monitor and verify the Demand Reduction Values of the Demand Resource project.

For Capacity Commitment Periods commencing on or after June 1, 2017, all Demand Response Assets must be metered at the Retail Delivery Point.

For Capacity Commitment Periods commencing on or after June 1, 2017, if the Real-Time Emergency Generation Asset cannot operate synchronized to the grid, and there is no Demand Response Asset at the same facility, the Real-Time Emergency Generation Asset can be metered at the Retail Delivery Point or at the Real-Time Emergency Generation Asset. If the Real-Time Emergency Generation Asset is capable of operating synchronized to the grid or there is a Demand Response Asset at the same facility then both the Retail Delivery Point and the Real-Time Emergency Generation Asset must be metered. For Capacity Commitment Periods commencing on or after June 1, 2017, Market Participants with Real-Time Emergency Generation Assets must utilize a remote terminal unit for communicating telemetry and receiving Dispatch Instructions, and the metering equipment used to measure the performance of a Real-Time Emergency Generation Asset must meet the requirements of Section E2.2.1(a), (b), and (c), must be tested pursuant to Section E2.2.3, and are subject to auditing pursuant to Section E2.2.4.

For Capacity Commitment Periods commencing on or after June 1, 2017, if a Real-Time Emergency Generation Asset is metered at the generator, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Output. If a Real-Time Emergency Generation Asset is only metered at the Retail Delivery Point, the associated Real-Time Emergency Generation Resource's Demand Reduction Value shall be calculated based upon the Average Hourly Load Reduction.

III.13.1.4.3.2.1. No Performance Data to Determine Demand Reduction Values.

Should a new Demand Resource, other than a Demand Response Capacity Resource, enter service at a time such that there is no performance data for June, July, August, December or January upon which to establish summer or winter seasonal Demand Reduction Values, and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, then the summer or winter seasonal Demand Reduction Values will be the simple average of its Demand Reduction Values for those months with a Capacity Supply Obligation. For a new Demand Resource, other than a Demand Response Capacity Resource, that enters service outside of the summer DR Auditing Period or winter DR Auditing Period and the Demand Resource has relieved itself of its Capacity Supply Obligation for those months through a Capacity Supply Obligation Bilateral or reconfiguration auction, the Demand Resource Commercial Operation Audit results shall be used in the determination of the summer or winter seasonal Demand Reduction Value.

III.13.1.4.3.3. ISO Review of Measurement and Verification Documents.

The ISO shall review the Measurement and Verification Documents and complete such review and identify any necessary modifications in accordance with the Forward Capacity Auction qualification process as described in Section III.13.1 and pursuant to the ISO New England Manuals. In its review of the Measurement and Verification Documents, the ISO may consult with the Project Sponsor to seek clarification, to gather additional necessary information, or to address questions or concerns arising from the materials submitted. At the discretion of the ISO, the ISO may consider revisions or additions to the Measurement and Verification Documents resulting from such consultation; provided, however, that in no case shall the ISO consider revisions or additions to the Measurement and Verification Documents if the ISO believes that such consideration cannot be properly accomplished within the time periods established for the qualification process.

III.13.1.4.3.4. Measurement and Verification Costs.

Costs associated with measurement and verification of the Demand Resource project shall be borne by the Demand Resource Project Sponsor. Demand Resource Project Sponsors submitting application materials and Measurement and Verification Documents for review during the Forward Capacity Auction qualification process shall be subject to the Qualification Process Cost Reimbursement Deposit, as described in Section III.13.1.9.3.

III.13.1.4.4. Dispatch of Active Demand Resources During Event Hours.

III.13.1.4.4.1. Notification of Demand Resource Forecast Peak Hours.

The ISO shall issue notice to Market Participants concerning Demand Resource Forecast Peak Hours on the day before the relevant Operating Day. The notice issued pursuant to this section is for informational purposes only and shall not constitute a Dispatch Instruction.

III.13.1.4.4.2. Dispatch of Demand Resources During Real-Time Demand Resource Dispatch Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Demand Response Resources to curtail and restore loads during Real-Time Demand Resource Dispatch Hours. Dispatch Instructions shall apply to Real-Time Demand Response Resources. The amount of Demand Resources dispatched for each Real-Time Demand Resource Dispatch Hour will be the amount that the ISO determines is necessary to meet the reserve deficiency. The ISO may issue Dispatch Instructions that reduce or increase the amount dispatched in each hour.

III.13.1.4.4.3. Dispatch of Demand Resources During Real-Time Emergency Generation Event Hours.

The ISO shall issue Dispatch Instructions to Market Participants with Real-Time Emergency Generation Resources to curtail and restore loads during Real-Time Emergency Generation Event Hours. Dispatch Instructions shall apply to specific Real-Time Emergency Generation Resources. The amount of Real-Time Emergency Generation Resources dispatched for each Real-Time Emergency Generation Event Hour will be the amount the ISO determines is necessary to meet the reserve deficiency.

III.13.1.4.5. Selection of Active Demand Resources For Dispatch.

III.13.1.4.5.1. Management of Real-Time Demand Response Assets and Real-Time Demand Response Resources.

A Market Participant must manage its Real-Time Demand Response Assets that are registered as a component of a Real-Time Demand Response Resource as of the first of a month so that the Real-Time Demand Response Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Demand Response Assets cause, or potentially cause, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to restore the loads of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Demand Response Asset or to restore the load of a dispatched Real-Time Demand Response Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the restoration of that asset. Market Participants with Real-Time Demand Response Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Demand Response Resources consisting of an aggregation of more than one Real-Time Demand Response Asset shall report the load reduction and consumption, or generator output of the resource, to the ISO as the sum of the load reduction, consumption, or generator output of the individual assets making up that resource. Real-Time Demand Response Resources shall be assigned a unique resource identification number. The load reduction and consumption, or generator output of a Real-Time Demand Response Resource is reported to the ISO as a single set of values. A Real-Time Demand Response Resource shall consist of one or more Real-Time Demand Response Assets that are located within the same Dispatch Zone.

III.13.1.4.5.2. Management of Real-Time Emergency Generation Assets and Real-Time Emergency Generation Resources.

A Market Participant must manage its Real-Time Emergency Generation Assets that are registered as a component of a Real-Time Emergency Generation Resource as of the first of a month so that the Real-Time Emergency Generation Resource complies with Dispatch Instructions. If the operation or potential operation of Real-Time Emergency Generation Assets causes, or potentially causes, a reliability problem, the ISO may direct Market Participants to not dispatch such assets or to discontinue the output of such assets that have already been dispatched. If the ISO directs a Market Participant to not dispatch a Real-Time Emergency Generation Asset or to discontinue the output of a dispatched Real-Time Emergency Generation Asset, an adjustment to the dispatch and/or settlement process will be made to reflect the exclusion of that asset from dispatch or the discontinued output of that asset. Market Participants with Real-Time Emergency Generation Assets shall report to the ISO the load reduction and consumption, or generator output of each asset. Market Participants with Real-Time Emergency Generation Resources consisting of an aggregation of more than one Real-Time Emergency Generation Asset shall report the generator output of the resource to the ISO as the sum of the generator outputs of the individual assets making up that resource. Real-Time Emergency Generation Resources shall be assigned a unique resource identification number. The generator output of a Real-Time Emergency Generation Resource is reported to the ISO as a single set of values. A Real-Time Emergency Generation Resource shall consist of one or more Real-Time Emergency Generation Assets that are located within the same Dispatch Zone.

III.13.1.4.5.3. [Reserved.]

III.13.1.4.6. Conversion of Active Demand Resources Defined at the Load Zone to Active Demand Resources Defined at Dispatch Zones.

III.13.1.4.6.1. Establishment of Dispatch Zones.

The ISO shall establish Dispatch Zones that reflect potential transmission constraints within a Load Zone that are expected to exist during each Capacity Commitment Period. Dispatch Zones shall be used to establish the geographic location and dispatch of Demand Response Capacity Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation Resources. Dispatch Zones shall not change during a Capacity Commitment Period. For each Capacity Commitment Period, the ISO shall establish and publish Dispatch Zones by the beginning of the New Capacity Show of Interest Submission Window of the applicable Forward Capacity Auction. The ISO will review proposed Dispatch Zones with Market Participants prior to establishing and publishing final Dispatch Zones.

III.13.1.4.6.2. Disaggregation of Real-Time Demand Response Resources and Real-Time Emergency Generation Resources From Load Zones to Dispatch Zones.

III.13.1.4.6.2.1. Real-Time Demand Response Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Demand Response Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Demand Response Resource into one or more Real-Time Demand Response Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Demand Response Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation, in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.6.2.2. Real-Time Emergency Generation Resource Disaggregation.

Market Participants with a Capacity Supply Obligation that is being fulfilled using a Real-Time Emergency Generation Resource in a Load Zone shall, prior to the start of the relevant Capacity Commitment Period, disaggregate that Real-Time Emergency Generation Resource into one or more Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the original Load Zone. The sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within the Load Zone must be equal to the initial Capacity Supply Obligation within the original Load Zone. If the sum of the Capacity Values of the disaggregated Real-Time Emergency Generation Resources located within one or more Dispatch Zones within a Load Zone is less than the initial Capacity Supply Obligation by the start of the relevant Capacity Commitment Period, and the Market Participant does not transfer the entire difference through a Capacity Supply Obligation Bilateral or an annual reconfiguration auction by the beginning of the

relevant Capacity Commitment Period, then the Market Participant will be deemed to have failed to meet its Capacity Supply Obligation in which case the ISO shall terminate the Market Participant's Capacity Supply Obligation associated with the resource in the amount of the difference (which shall then be entered into subsequent reconfiguration auctions), terminate the Market Participant's right to any payments associated with the terminated Capacity Supply Obligation, and retain any applicable financial assurance associated with the terminated Capacity Supply Obligation.

III.13.1.4.7. [Reserved.]

III.13.1.4.8. [Reserved.]

III.13.1.4.9. Restrictions on Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Registration.

A Market Participant may not register and, if previously registered, must retire in accordance with Section III.13.1.4.9.1, a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of:

(a) the customers of Host Utilities that distributed more than 4 million MWh in the previous fiscal year if the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into the ISO-administered markets or programs, or

(b) the customers of Host Utilities that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into the ISO-administered markets or programs.

III.13.1.4.9.1. Requirement for Real-Time Demand Response Asset, Real-Time Emergency Generation Asset, On-Peak Demand Resource and Seasonal Peak Demand Resource Retirement.

A Market Participant must retire a previously registered Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or asset associated with an On-Peak Demand Resource or Seasonal Peak Demand Resource that is comprised of customers specified in subsections (a) or (b) of Section III.13.1.4.9 no later than 12 months from the date that the ISO receives notice that the relevant electric retail

regulatory authority prohibits such customer's demand response to be bid into the ISO-administered markets or programs or May 31, 2013, whichever is later.

III.13.1.4.10. Providing Information On Demand Response Capacity, Real-Time Demand Response and Real-Time Emergency Generation Resources.

If requested by a Market Participant with a registered Load Asset, the ISO will provide the following information about end-use customers served by the Market Participant: (a) whether the end-use customer's facility is registered with the ISO as part of an asset and whether the asset is associated with a Demand Response Resource, Real-Time Demand Response Resource or Real-Time Emergency Generation Resource, and; (b) the load reduction capability of the asset, as specified in the ISO's asset registration system, to which the end-use customer's facility is registered.

III.13.1.4.11. Assignment of Demand Assets to a Demand Resource.

The following mapping provisions apply to Demand Resources other than Demand Response Capacity Resources, the mapping for which is addressed in Appendix E to Market Rule 1.

(a) When a demand asset can be mapped to more than one Demand Resource, any demand assets shall be mapped to a commercial Demand Resource whose demand reduction capability is less than the lower of (i) its commercial capacity, as reflected in the resource's highest audit value or (ii) its highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period, before being mapped to a non-commercial Demand Resource or non-commercial increment of a Demand Resource.

(b) A demand asset cannot be unmapped from a Demand Resource if, following the unmapping, the sum of the audit values of the remaining demand assets that are mapped to the Demand Resource would be lower than the resource's highest Capacity Supply Obligation acquired for the current Capacity Commitment Period or any future Capacity Commitment Period.

III.13.1.5. Offers Composed of Separate Resources.

Separate resources seeking to participate together in a Forward Capacity Auction shall submit a composite offer form no later than 10 Business Days after the date on which the ISO provides qualification determination notifications, as described in Section III.13.1.1.2.8, Section III.13.1.2.4, and Section III.13.1.2.4.5.3. Offers composed of separate resources may not be modified or withdrawn after

the deadline for submission of the composite offer form. Separate resources may together participate in a Forward Capacity Auction as a single resource if the following conditions are met:

(a) In all months of the summer period (June through September where the summer resource is not a Demand Resource, April through November where the summer resource is a Demand Resource) of the Capacity Commitment Period, only one resource may be used to supply the amount of capacity offered during the entire summer period. In all months of the winter period (October through May where the summer resource is not a Demand Resource, December through March where the summer resource is a Demand Resource) of the Capacity Commitment Period, multiple resources may be combined to supply the amount of capacity offered, provided that: (i) the resources together meet the amount of the offer in all months of the winter period; and (ii) to combine for a month, that month must be considered a winter month for both the summer resource and the resource combining with that summer resource in that month.

(b) Each resource that is part of an offer composed of separate resources must qualify in accordance with all of the provisions of this Section III.13.1.5 applicable to that resource type. An offer composed of separate resources participates in the Forward Capacity Auction in accordance with the resource type of the resource providing capacity in the summer period. A resource electing (pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5) to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which its New Capacity Offer clears shall not be eligible to participate in an offer composed of separate resources as the resource providing capacity in the summer period in the Forward Capacity Auction in which the resource is a New Generating Capacity Resource or New Demand Resource.

(c) The summer Qualified Capacity of an offer composed of separate resources shall be the summer Qualified Capacity of the single resource that will provide the Capacity Supply Obligation during the summer period. If the summer Qualified Capacity of an offer composed of separate resources is greater than the winter capacity for any month, then the provisions of Section III.13.1.2.2.5.2 shall apply, even where any of the resources comprising the offer composed of separate resources is an Intermittent Power Resource or Intermittent Settlement Only Resource. If the winter capacity of the offer composed of separate resources in any month is higher than the summer Qualified Capacity, then the capacity offered from the winter resources will be reduced pro-rata to equal the summer Qualified Capacity.

(d) If an offer is composed of separate resources, and is intended to meet the Local Sourcing Requirement in an import-constrained Capacity Zone, then each resource comprising the offer must be located in that import-constrained Capacity Zone.

(e) If an offer is composed of separate resources, and is intended to meet the capacity requirement in the Rest-of-Pool Capacity Zone, then each resource comprising the offer must be located in a Capacity Zone that is not export-constrained.

(f) If an offer is composed of separate resources, and is for capacity in an export-constrained Capacity Zone, then each resource comprising the offer must be located inside of the export-constrained Capacity Zone or be located in any non-export constrained Capacity Zone.

(g) A Real-Time Emergency Generation Resource may only participate in an offer composed of separate resources as a winter resource if the summer resource is also a Real-Time Emergency Generation Resource.

III.13.1.5.A. Notification of FCA Qualified Capacity.

No later than 5 Business Days after the deadline for submission of offers composed of separate resources, the ISO shall notify the Project Sponsor or Lead Market Participant for each New Generating Capacity Resource, New Import Capacity Resource, and New Demand Resource of the resource's final FCA Qualified Capacity for the Forward Capacity Auction. Such notification will detail the resource's financial assurance requirements in accordance with Section III.13.1.9.

III.13.1.6. Self-Supplied FCA Resources.

Where a Project Sponsor elects to designate all or a portion of a New Generating Capacity Resource or an Existing Generating Capacity Resource as a Self-Supplied FCA Resource, the Project Sponsor must make such designation in writing to the ISO no later than the date by which the Project Sponsor is required to submit the financial assurance deposit and, if the Project Sponsor is not also the associated load serving entity, the Project Sponsor must at that time provide written confirmation from the load serving entity regarding the Self-Supplied FCA Resource designation. A New Import Capacity Resource or Existing Import Capacity Resource may be designated as a Self-Supplied FCA Resource. All Self-Supplied FCA Resources shall be subject to the eligibility and locational requirements in this Section III.13.1.6. If designated as a Self-Supplied FCA Resource and otherwise accepted in the qualification process, the resource will clear in the Forward Capacity Auction as described in Section III.13.2.3.2(c)

and, with the exception of demand programs for Self-Supplied FCA Resources, shall offset an equal amount of the load serving entity's share of Installed Capacity Requirement in the Capacity Commitment Period. A load serving entity seeking to self-supply using a Demand Resource shall realize the benefit through the actual reduction in its annual system coincident peak load, shall not receive credit for a resource and, therefore, is not required to participate in the qualification process described in this Section III.13.1. All designations as a Self-Supplied FCA Resource in the Forward Capacity Auction qualification process are binding.

III.13.1.6.1. Self-Supplied FCA Resource Eligibility.

Where all or a portion of a resource is designated as a Self-Supplied FCA Resource, it shall also maintain its status as a New Generating Capacity Resource, Existing Generating Capacity Resource, New Import Capacity Resource or Existing Import Capacity Resource, and must satisfy the Forward Capacity Auction qualification process requirements set forth in the remainder of Section III.13.1 applicable to that resource type, in addition to the requirements of this Section III.13.1.6. Where an offer composed of separate resources is designated as a Self-Supplied FCA Resource, all of the requirements and deadlines specified in Section III.13.1.5 shall apply to that offer, in addition to the requirements of this Section III.13.1.6. The total quantity of capacity that an load serving entity designates as Self-Supplied FCA Resources may not exceed the load serving entity's projected share of the Installed Capacity Requirement during the Capacity Commitment Period which shall be calculated by determining the load serving entity's most recent percentage share of the Installed Capacity Requirement multiplied by the projected Installed Capacity Requirement for the commitment year. No resource may be designated as a Self-Supplied FCA Resource for more MW than the lesser of that resource's summer Qualified Capacity and winter Qualified Capacity.

III.13.1.6.2. Locational Requirements for Self-Supplied FCA Resources.

In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource for a load in an import-constrained Capacity Zone, the Self-Supplied FCA Resource must be located in the same Capacity Zone as the associated load, unless the Self-Supplied FCA Resource is a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights. In order to participate in the Forward Capacity Auction as a Self-Supplied FCA Resource in an export-constrained Capacity Zone for a load outside that export-constrained Capacity Zone, the Self-Supplied FCA Resource must be a pool-planned unit or other unit with a special allocation of Capacity Transfer Rights.

III.13.1.7. Internal Market Monitor Review of Offers and Bids.

In addition to the other provisions of this Section III.13.1, the Internal Market Monitor shall have the authority to review in the qualification process each resource's summer and winter Seasonal Claimed Capability if it is significantly lower than historical values, and if the Internal Market Monitor determines that it may be an attempt to exercise physical withholding, the matter will be referred to the Commission in accordance with the protocols set forth in Appendix A to the Commission's Market Monitoring Policy Statement (111 FERC ¶ 61,267 (2005)). Where an entity submits: (i) an offer as a New Generating Capacity Resource, a New Import Capacity Resource or a New Demand Resource; and (ii) a Static De-List Bid, a Permanent De-List Bid, an Export Bid or an Administrative Export De-List Bid in the same Forward Capacity Auction, the Internal Market Monitor shall take appropriate steps to ensure that the resource bid to de-list or export in the Forward Capacity Auction is not inappropriately replaced by that new capacity in a subsequent reconfiguration auction or Capacity Supply Obligation Bilateral. In its review of any offer or bid pursuant to this Section III.13.1.7, the Internal Market Monitor may consult with the Project Sponsor or Market Participant, as appropriate, to seek clarification, or to address questions or concerns regarding the materials submitted.

III.13.1.8. Publication of Offer and Bid Information.

(a) Resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located about each Permanent De-list Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(b) The quantity, price, and Load Zone (or interface, as applicable) in which the resource is located of each Static De-List Bid will be posted no later than 15 days after the Forward Capacity Auction is conducted.

(c) Name of submitter, quantity, and interface of Export Bids and Administrative Export Bids shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(d) Name of submitter, quantity, and interface about offers from New Import Capacity Resources shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(e) If a Permanent De-List Bid above $1.00/kW-month or a Static De-List Bid is approved by the Internal Market Monitor, resource name, quantity, price, and Load Zone (or interface, as applicable) in which the resource is located shall be published no later than 15 days after the Forward Capacity Auction is conducted.

(f) The name of each Lead Market Participant submitting de-list bids, as well as the number and type of de-list bids submitted by each Lead Market Participant, shall be published no later than three Business Days after the ISO issues the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7. Authorized Persons of Authorized Commissions will be provided confidential access to full information about posted Static De-list Bids and Permanent De-List Bids upon request pursuant to Section 3.3 of the ISO New England Information Policy.

III.13.1.9. Financial Assurance.

Except as noted in this Section III.13.1.9, all financial assurance requirements associated with Forward Capacity Auctions and annual reconfiguration auctions and other payments and charges resulting from the Forward Capacity Market shall be governed by the ISO New England Financial Assurance Policy. The ISO and the NEPOOL Budget and Finance Subcommittee shall reconsider these financial assurance requirements no later than five years after the first Forward Capacity Auction is conducted.

III.13.1.9.1. Financial Assurance for New Generating Capacity Resources and New Demand Resources Participating in the Forward Capacity Auction.

In order to participate in any Forward Capacity Auction, New Generating Capacity Resources (including Conditional Qualified New Generating Capacity Resources) and New Demand Resources shall be required to meet the financial assurance requirements as described in the ISO New England Financial Assurance Policy. Timely payment of the financial assurance deposit specified in the ISO New England Financial Assurance Policy by the Project Sponsor for a New Generating Capacity Resource or New Demand Resource accepted for participation in the Forward Capacity Auction constitutes a commitment to offer the full FCA Qualified Capacity of that New Generating Capacity Resource or New Demand Resource in the Forward Capacity Auction at the starting price. If this financial assurance deposit is not received within the timeframe specified in the ISO New England Financial Assurance Policy, the New Generating Capacity Resource or New Demand Resource shall not be permitted to participate in the Forward Capacity Auction. If capacity offered by the New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit shall be applied toward the resource's financial assurance obligation, as described in the ISO New England Financial Assurance Policy. If no capacity offered by that New Generating Capacity Resource or New Demand Resource clears in the Forward Capacity Auction, the deposit will be returned pursuant to the terms of the ISO New England Financial Assurance Policy.

III.13.1.9.2. Financial Assurance for New Generating Capacity Resources and New Demand Resources Clearing in a Forward Capacity Auction.

Where a New Generating Capacity Resource's offer or a New Demand Resource's offer is accepted in a Forward Capacity Auction, that resource must provide financial assurance as described in the ISO New England Financial Assurance Policy.

III.13.1.9.2.1. Failure to Provide Financial Assurance or to Meet Milestone.

If a New Generating Capacity Resource or New Demand Resource: (i) fails to provide the required financial assurance on any required date for any reason; or (ii) has its Capacity Supply Obligation terminated by the ISO pursuant to Section III.13.3.4(c), it shall lose its Capacity Supply Obligation (which shall then be entered by the ISO into subsequent annual reconfiguration auctions) and its right to any payments associated with that Capacity Supply Obligation, and it shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation.

III.13.1.9.2.2. Release of Financial Assurance.

Once a New Generating Capacity Resource or New Demand Resource achieves Commercial Operation and is tested for its capacity rating, its financial assurance obligation shall be released pursuant to the terms of the ISO New England Financial Assurance Policy and it shall have the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy. If a New Generating Capacity Resource or New Demand Resource is only capable of delivering less than the amount of capacity that cleared in the Forward Capacity Auction, then the portion of its financial assurance associated with the shortfall shall be forfeited. Any resulting shortfall in capacity shall then be entered by the ISO into subsequent annual reconfiguration auctions.

III.13.1.9.2.2.1. [Reserved.]

III.13.1.9.2.3. Forfeit of Financial Assurance.

Where any financial assurance is forfeited pursuant to the provisions of this Section III.13, there shall be no further coverage for such forfeit under the ISO New England Billing Policy. Any financial assurance that is forfeited pursuant to the provisions of this Section III.13 shall be used to reduce payments incurred by load in the relevant Capacity Zone to replace that capacity.

III.13.1.9.2.4. Financial Assurance for New Import Capacity Resources.

A New Import Capacity Resource that is backed by a new External Resource shall be subject to the same financial assurance requirements as a New Generating Capacity Resource, as described in Section III.13.1.9.1 and Section III.13.1.9.2. Once the new External Resource achieves Commercial Operation, the New Import Capacity Resource shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as described in Section III.13.1.9. A New Import Capacity Resource that is backed by one or more existing External Resources or by an external Control Area shall be subject to the same financial assurance requirements as an Existing Generating Capacity Resource, as governed by the ISO New England Financial Assurance Policy.

III.13.1.9.3. Qualification Process Cost Reimbursement Deposit.

For each New Capacity Show of Interest Form and New Demand Resource Show of Interest Form submitted for the purposes of qualifying for either a Forward Capacity Auction or reconfiguration auction, the Project Sponsor must submit to the ISO a refundable deposit in the amount shown in the table below ("Qualification Process Cost Reimbursement Deposit"). The Qualification Process Cost Reimbursement Deposit must be received in accordance with the ISO New England Billing Policy. Such deposit shall be used for costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. An additional Qualification Process Cost Reimbursement Deposit is not required if: (i) the Project Sponsor is actively seeking qualification for another Forward Capacity Auction or annual reconfiguration auction, or is having the project's critical path schedule monitored pursuant to Section III.13.3; and (ii) the costs already incurred in the qualification process and critical path schedule monitoring do not equal or exceed 90 percent of the amount of the previously-submitted Qualification Process Cost Reimbursement Deposit(s). The ISO shall provide the Project Sponsor with an annual statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. In any case where resources are aggregated or disaggregated, the associated Qualification Process Cost Reimbursement Deposits will be adjusted as appropriate. After aggregation or disaggregation of resources, historical data regarding the costs already incurred in the qualification process of the original resources will no longer be provided. Coincident with the issuance of the annual statement, where incurred costs are equal to or greater than 90 percent of the Qualification Process Cost Reimbursement Deposit(s) previously submitted, the ISO will issue an invoice in the amount determined pursuant to the Qualification Process Cost Reimbursement Deposit table contained in Section III.13.1.9.3.1 plus any excess of costs incurred to date by the ISO and its consultants, including

the documented and reasonably-incurred costs of the affected Transmission Owners, associated with the qualification process described in Section III.13.1 and with the critical path schedule monitoring described in Section III.13.3. Any refunds that may result from aggregation of resources will be issued coincident with the annual statement. Payment on the invoice must be received in accordance with the ISO New England Billing Policy. If the Project Sponsor fails to pay the amount due by the stated due date, the ISO will consider the resources that were invoiced withdrawn by the Project Sponsor. Such a withdrawal shall be irrevocable, and payment on the invoice after the due date will not remedy the failure to pay or the withdrawal.

III.13.1.9.3.1. Partial Waiver Of Deposit.

A portion of the deposit shall be waived when there is an active Interconnection Request and an executed Interconnection Feasibility Study Agreement or Interconnection System Impact Study Agreement under Schedule 22 or 23 of the OATT or where a resource modification does not require a revision to the Interconnection Agreement.

New Generating Resources ≥ 20 MW	**New Generating Resources < 20 MW and ≥ 2 MW**	**Imports and New Demand Resources (including Distributed Generation)**		**New Generating Resources < 2 MW**
Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources	*Including Up-rates, Re-powering, Environmental Compliance & Intermittent Power Resources*			
$25,000	$7,500	$1,000		$500
With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement	*With Executed Interconnection Feasibility Study Agreement or System Impact Study Agreement*			
$15,000	$6500	n/a		n/a

III.13.1.9.3.2. Settlement of Costs.

III.13.1.9.3.2.1. Settlement Of Costs Associated With Resources Participating In A Forward Capacity Auction Or Reconfiguration Auction.

Upon the latter of: (i) the first day of the Capacity Commitment Period for which a resource offers into the Forward Capacity Market or (ii) the date on which the entire resource is accepted by the ISO for Commercial Operation, the ISO shall provide the Project Sponsor with a statement in writing of the costs

incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. If any portion of the Qualification Process Cost Reimbursement Deposit exceeds the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s) associated with the qualification process and critical path schedule monitoring, the ISO shall refund to the Project Sponsor the excess including interest calculated in accordance with 18 CFR § 35.19a(a)(2). If the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of the affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring exceed the Qualification Process Cost Reimbursement Deposit, the Project Sponsor shall pay such excess, including interest calculated in accordance with 18 CFR § 35.19a(a)(2) – For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.2. Settlement Of Costs Associated With Resources That Withdraw From A Forward Capacity Auction Or Reconfiguration Auction.

Upon the withdrawal or failure to meet the requirements of the qualification process set forth in Section III.13.1, the ISO shall provide the Project Sponsor with a statement in writing of the costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. A Project Sponsor that withdraws or is deemed to have withdrawn its request for qualification shall pay to the ISO all costs prudently incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), associated with the qualification process and critical path schedule monitoring. The ISO shall refund to the Project Sponsor any portion of the Qualification Process Cost Reimbursement Deposit that exceeds the costs associated with the qualification process and critical path schedule monitoring incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), including interest calculated in accordance with 18 CFR § 35.19a(a)(2). The ISO shall charge the Project Sponsor the amount of such costs incurred by the ISO and its consultants, including the documented and reasonably-incurred costs of affected Transmission Owner(s), that exceeds the Qualification Process Cost Reimbursement Deposit, including interest calculated in accordance with 18 CFR § 35.19a(a)(2). For Demand Resources, the ISO shall provide all of the above concurrently with the annual statement required under Section III.13.1.9.3.

III.13.1.9.3.2.3. Crediting Of Reimbursements.

Cost reimbursements received (excluding amounts passed through to the ISO's consultants and to affected Transmission Owner(s)) by the ISO pursuant to this Section III.13.1.9.3.2 shall be credited against revenues received by the ISO pursuant to Section IV.A.6.1 of the Transmission, Markets and Services Tariff.

III.13.1.10. Forward Capacity Auction Qualification Schedule.

The table below provides the major dates and deadlines for each of the first eight Forward Capacity Auctions.

New Capacity Show of Interest Submission Window	Existing Capacity Qualification Deadline	New Capacity Qualification Deadline	First Day of Forward Capacity Auction for the Capacity Commitment Period	Capacity Commitment Period Begins
For all resources except Demand Resources, Nov. 1, 2006 through Jan. 2, 2007 For Demand Resources, Dec. 18, 2006 through Feb. 28, 2007	Apr. 30, 2007	June 15, 2007	Feb. 4, 2008	June 1, 2010
Sept. 18, 2007 through Nov. 14, 2007	Mar. 14, 2008	Apr. 29, 2008	Dec. 8, 2008	June 1, 2011
July 15, 2008 through Sep. 16, 2008	Feb. 3, 2009	Feb. 17, 2009	Oct. 5, 2009	June 1, 2012
May 15, 2009 through July 14, 2009	Dec. 1, 2009	Dec. 15, 2009	Aug. 2, 2010	June 1, 2013
Mar. 15, 2010 through May 14, 2010	Oct. 1, 2010	Oct. 15, 2010	June 6, 2011	June 1, 2014
Mar. 1, 2011 through Mar. 14, 2011	Aug. 1, 2011	Aug. 15, 2011	Apr. 2, 2012	June 1, 2015
Jan. 3, 2012 through Jan. 17, 2012	June 1, 2012	June 15, 2012	Feb. 4, 2013	June 1, 2016
Feb. 14, 2013 through Feb. 28, 2013	June 3, 2013	June 17, 2013	Feb. 3, 2014	June 1, 2017

Beginning with the timeline for the Capacity Commitment Period beginning on June 1, 2017 (the eighth Forward Capacity Auction), and for each Capacity Commitment Period thereafter, the deadlines will be consistent for each Capacity Commitment Period, as follows:

(a) each Capacity Commitment Period shall begin in June;

(b) the New Capacity Show of Interest Submission Window will be in February (after the Forward Capacity Auction for the prior Capacity Commitment Period), approximately four years and three months before the beginning of the Capacity Commitment Period;

(c) the Existing Capacity Qualification Deadline will be in June just over four years before the beginning of the Capacity Commitment Period;

(d) the New Capacity Qualification Deadline will be in June or July that is just under four years before the beginning of the Capacity Commitment Period; and

(e) the Forward Capacity Auction for the Capacity Commitment Period will begin in February approximately three years and four months before the beginning of the Capacity Commitment Period.

The table below shows this generic timeline for the Capacity Commitment Period beginning in yer "X", where X is any year after 2015.

New Capacity Show of Interest Submission Window	**Existing Capacity Qualification Deadline**	**New Capacity Qualification Deadline**	**First Day of Forward Capacity Auction for the Capacity Commitment Period**	**Capacity Commitment Period Begins**
Feb. (X-4)	June (X-4)	June/July (X-4)	Feb. (X-3)	June X

III.13.2. Annual Forward Capacity Auction.

III.13.2.1. Timing of Annual Forward Capacity Auctions.

Except with respect to the first six Forward Capacity Auctions (as described in Section III.13.1.10), each Forward Capacity Auction will be conducted beginning on the first Monday in the February that is approximately three years and four months before the beginning of the associated Capacity Commitment Period (unless, no later than the immediately preceding December 1, an alternative date is announced by the ISO), or, where exigent circumstances prevent the start of the Forward Capacity Auction at that time, as soon as possible thereafter.

III.13.2.2. Amount of Capacity Purchased in Each Forward Capacity Auction.

Each Forward Capacity Auction shall procure one hundred percent of the Installed Capacity Requirement (net of HQICCs) approved by the Commission for the associated Capacity Commitment Period, except as a result of the Capacity Rationing Rule, as described in Sections III.13.2.6 and III.13.2.7.4. The sum of the Hydro-Quebec Interconnection Capability Credits and import capacity purchased over the Phase I/II HVDC-TF interconnection shall not exceed the capacity transfer limit of those facilities, as determined by the ISO.

III.13.2.3. Conduct of the Forward Capacity Auction.

The Forward Capacity Auction shall be a descending clock auction, which will determine, subject to the provisions of Section III.13.2.7, the Capacity Clearing Price for each Capacity Zone modeled in that Forward Capacity Auction pursuant to Section III.12.4, and the Capacity Clearing Price for certain offers from New Import Capacity Resources and Existing Import Capacity Resources pursuant to Section III.13.2.3.3(d). The Forward Capacity Auction shall determine the outcome of all offers and bids accepted during the qualification process and submitted during the auction. Each Forward Capacity Auction shall be conducted as a series of rounds, which shall continue (for up to five consecutive Business Days, with up to eight rounds per day, absent extraordinary circumstances) until the Forward Capacity Auction is concluded for all modeled Capacity Zones in accordance with the provisions of Section III.13.2.3.3. Each round of the Forward Capacity Auction shall consist of the following steps, which shall be completed simultaneously for each Capacity Zone included in the round:

III.13.2.3.1. Step 1: Announcement of Start-of-Round Price and End-of-Round Price.

For each round, the auctioneer shall announce a single Start-of-Round Price (the highest price associated with a round of the Forward Capacity Auction) and a single (lower) End-of-Round Price (the lowest price

associated with a round of the Forward Capacity Auction). In the first round, the Start-of-Round Price shall equal the Forward Capacity Auction Starting Price for all modeled Capacity Zones. In each round after the first round, the Start-of-Round Price shall equal the End-of-Round Price from the previous round.

III.13.2.3.2. Step 2: Compilation of Offers and Bids.

The auctioneer shall compile all of the offers and bids for that round, as follows:

(a) **Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.**

(i) The Project Sponsor for any New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource accepted in the qualification process for participation in the Forward Capacity Auction may submit an offer (a "New Capacity Offer") indicating the quantity of capacity that the Project Sponsor would commit to provide from the resource (in the associated modeled Capacity Zone during the qualification process) during the Capacity Commitment Period at that round's prices. A New Capacity Offer shall be defined by the submission of one to five prices, each strictly less than the Start-of-Round Price but greater than or equal to the End-of-Round Price, and an associated quantity in the associated modeled Capacity Zone. Each price shall be expressed in units of dollars per kilowatt-month to an accuracy of at most three digits to the right of the decimal point, and each quantity shall be expressed in units of MWs to an accuracy of at most three digits to the right of the decimal point. Such a New Capacity Offer shall imply a supply curve indicating quantities offered at all of that round's prices, pursuant to the convention of Section III.13.2.3.2(a)(iii).

(ii) If the Project Sponsor of a New Generating Capacity Resource, a New Import Capacity Resource, or New Demand Resource elects to offer in a Forward Capacity Auction, the Project Sponsor must offer the resource's full FCA Qualified Capacity at the Forward Capacity Auction Starting Price in the first round of the auction. A New Capacity Offer for a resource may in no event be for greater capacity than the resource's full FCA Qualified Capacity at any price. A New Capacity Offer for a resource may not be for less capacity than the resource's Economic Minimum Limit at any price, except where the New Capacity Offer is for a capacity quantity of zero.

(iii) Let the Start-of-Round Price and End-of-Round Price for a given round be P_S and P_E, respectively. Let the m prices ($1 \leq m \leq 5$) submitted by a Project Sponsor for a modeled Capacity Zone be $p_1, p_2, \ldots, p_m$, where $P_S > p_1 > p_2 > \ldots > p_m \geq P_E$, and let the associated quantities submitted for a New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource be $q_1, q_2, \ldots, q_m$. Then the Project Sponsor's supply curve, for all prices strictly less than P_S but greater than or equal to P_E, shall be taken to be:

$$S(p) = \begin{cases} q_0, & \text{if } p > p_1, \\ q_1, & \text{if } p_2 < p \leq p_1, \\ q_2, & \text{if } p_3 < p \leq p_2, \\ \ldots \quad \ldots & , \\ q_m, & \text{if } p \leq p_m. \end{cases}$$

where, in the first round, q_0 is the resource's full FCA Qualified Capacity and, in subsequent rounds, q_0 is the resource's quantity offered at the lowest price of the previous round.

(iv) [Reserved.]

(v) A New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource may not include any capacity in a New Capacity Offer during the Forward Capacity Auction at any price below the resource's New Resource Offer Floor Price. The amount of capacity included in each New Capacity Offer at each price shall be included in the aggregate supply curves at that price as described in Section III.13.2.3.3.

(b) **Bids from Existing Capacity Resources Accepted in Qualification.** Static De-List Bids, Permanent De-List Bids, and Export Bids from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources submitted and accepted in the qualification process (or as directed by the Commission) shall be automatically bid into the appropriate round(s) of the Forward Capacity Auction, such that each such resource's summer Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3. until any Static De-List Bid, Permanent De-List Bid, or Export Bid clears in the Forward Capacity Auction, as described in Section III.13.2.5.2, and is removed from the aggregate supply curves. Administrative Export De-List Bids shall be automatically entered into the first round of the Forward Capacity Auction at the Forward Capacity Auction Starting Price. If the amount of capacity associated with Export Bids for an interface exceeds the transfer limit of

that interface (minus any accepted Administrative De-List Bids over that interface), then the set of Export Bids associated with that interface equal to the interface's transfer limit (minus any accepted Administrative De-List Bids over that interface) having the highest bid prices shall be included in the auction as described above; capacity for which Export Bids are not included in the auction as a result of this provision shall be entered into the auction pursuant to Section III.13.2.3.2(c).

(c) **Existing Capacity Resources Not Having Accepted De-List or Export Bids and Self-Supplied FCA Resources**. Each Existing Generating Capacity Resource, Existing Import Capacity Resource, and Existing Demand Resource that did not submit a Static De-List Bid, a Permanent De-List Bid, an Export Bid, or an Administrative Export De-List Bid in its Existing Capacity Qualification Package, or an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource that did not have any such bid accepted in the qualification process, and each existing Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its FCA Qualified Capacity, such that the resource's FCA Qualified Capacity will be included in the aggregate supply curves as described in Section III.13.2.3.3, except where such resource, if permitted, submits an appropriate Dynamic De-List Bid, as described in Section III.13.2.3.2(d). Each new Self-Supplied FCA Resource shall be automatically entered into each round of the Forward Capacity Auction at its designated self-supplied quantity at prices at or above the resource's New Resource Offer Floor Price, such that the resource's designated self-supply quantity will be included in the aggregate supply curves as described in Section III.13.2.3.3.

(d) **Dynamic De-List Bids.** In any round of the Forward Capacity Auction in which prices are below $1.00/kW-month, any Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Resource (but not any Self-Supplied FCA Resources) may submit a Dynamic De-List Bid at prices below $1.00/kW-month. Such a bid shall be defined by the submission of one to five prices, each less than $1.00/kW-month (or the Start-of-Round Price, if lower than $1.00/kW-month) but greater than or equal to the End-of-Round Price, and a single quantity associated with each price. Such a bid shall be expressed in the same form as specified in Section III.13.2.3.2(a)(i) and shall imply a curve indicating quantities at all of that round's relevant prices, pursuant to the convention of Section III.13.2.3.2(a)(iii). The curve may in no case increase the quantity offered as the price decreases. A dynamic De-List Bid may not offer less capacity than the resource's Economic Minimum Limit at any price, except where the amount of capacity offered is zero. All Dynamic De-List Bids are subject to a reliability review as described in Section III.13.2.5.2.5, and if not rejected for reliability reasons, shall be included in the round in the same manner as Static De-List Bids as described in Section III.13.2.3.2(b).

Where a resource elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5 to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, the capacity associated with any resulting Capacity Supply Obligation may not be subject to a Dynamic De-List Bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply. Where a Lead Market Participant submits any combination of Dynamic De-List Bid, Static De-List Bid, Export Bid, and Administrative Export De-List Bid for a single resource, none of the prices in a set of price-quantity pairs associated with a bid may be the same as any price in any other set of price-quantity pairs associated with another bid for the same resource.

(e) **Repowering**. Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period. If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

(f) **Conditional Qualified New Generating Capacity Resources.** Offers associated with a resource participating in the Forward Capacity Auction as a Conditional Qualified New Generating Capacity

Resource pursuant to Section III.13.1.1.2.3(f) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(f). The Project Sponsor shall offer such a Conditional Qualified New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). An offer from at most one resource at a Conditional Qualified New Generating Capacity Resource's location will be permitted to clear (receive a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction. As long as a positive quantity is offered at the End-of-Round Price in the final round of the Forward Capacity Auction by the resource having a higher queue priority at the Conditional Qualified New Generating Capacity Resource's location, as described in Section III.13.1.1.2.3(f), then no capacity from the Conditional Qualified New Generating Capacity Resource shall clear. If at any price greater than or equal to the End-of-Round Price in the final round of the Forward Capacity Auction, zero quantity is offered from the resource having higher queue priority at the Conditional Qualified New Generating Capacity resource's location, as described in Section III.13.1.1.2.3(f), then the auctioneer shall consider capacity offered from the Conditional Qualified New Generating Capacity Resource in the determination of clearing, including the application of Section III.13.2.7.

(g) **Mechanics**. Offers and bids that may be submitted during a round of the Forward Capacity Auction must be received between the starting time and ending time of the round, as announced by the auctioneer in advance. The ISO at its sole discretion may authorize a participant in the auction to complete or correct its submission after the ending time of a round, but only if the participant can demonstrate to the ISO's satisfaction that the participant was making reasonable efforts to complete a valid offer submission before the ending time of the round, and only if the ISO determines that allowing the completion or correction will not unreasonably disrupt the auction process. All decisions by the ISO concerning whether or not a participant may complete or correct a submission after the ending time of a round are final.

III.13.2.3.3. Step 3: Determination of the Outcome of Each Round.

The auctioneer shall use the offers and bids for the round as described in Section III.13.2.3.2 to determine the aggregate supply curves for the New England Control Area and for each modeled Capacity Zone included in the round. The aggregate supply curve for the New England Control Area (the "Total System Capacity") shall reflect at each price the sum of (the amount of capacity offered in all Capacity Zones modeled as import-constrained Capacity Zones at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (the amount of capacity offered in the

Rest-of-Pool Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources)) plus (for each Capacity Zone modeled as an export-constrained Capacity Zone, the lesser of the amount of capacity offered in the Capacity Zone at that price (excluding capacity offered from New Import Capacity Resources and Existing Import Capacity Resources) or the Capacity Zone's Maximum Capacity Limit) plus (for each interface between the New England Control Area and an external Control Area, the lesser of that interface's approved capacity transfer limit (net of tie benefits) or the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources). In computing the Total System Capacity, capacity associated with any New Capacity Offer at any price greater than the Forward Capacity Auction Starting Price will not be included in the tally of total capacity at the Forward Capacity Auction Starting Price for that Capacity Zone. In no event shall the Capacity Clearing Price for a Capacity Zone be greater than the Forward Capacity Auction Starting Price for that Capacity Zone. On the basis of these aggregate supply curves, the auctioneer shall determine the outcome of the round for each modeled Capacity Zone as follows:

(a) **Import-Constrained Capacity Zones.**

For a Capacity Zone modeled as an import-constrained Capacity Zone, if either of the following two conditions is met during the round:

(1) the aggregate supply curve for the import-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Capacity Zone's Local Sourcing Requirement; or

(2) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which either of the two conditions above are satisfied, subject to the other provisions of this Section III.13.2. If neither of the two conditions above are met in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-

Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(b) **Rest-of-Pool Capacity Zone**. For the Rest-of-Pool Capacity Zone, if the Total System Capacity adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs), then the Forward Capacity Auction for the Rest-of-Pool Capacity Zone is concluded and the Rest-of-Pool Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for the Rest-of-Pool Capacity Zone shall be set at the highest price at which the Total System Capacity is less than or equal to the Installed Capacity Requirement (net of HQICCs), subject to the other provisions of this Section III.13.2. If the Total System Capacity exceeds the Installed Capacity Requirement (net of HQICCs) at the End-of-Round Price, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement (net of HQICCs)) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and the Rest-of-Pool Capacity Zone will be included in the next round of the Forward Capacity Auction.

(c) **Export-Constrained Capacity Zones**. For a Capacity Zone modeled as an export-constrained Capacity Zone, if both of the following two conditions are met during the round:

(i) the aggregate supply curve for the export-constrained Capacity Zone, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), is equal to or below the Capacity Zone's Maximum Capacity Limit; and

(ii) the Total System Capacity, adjusted as necessary in accordance with Section III.13.2.6 (Capacity Rationing Rule), equals or is less than the Installed Capacity Requirement (net of HQICCs);

then the Forward Capacity Auction for that Capacity Zone is concluded and such Capacity Zone will not be included in further rounds of the Forward Capacity Auction. The Capacity Clearing Price for that Capacity Zone shall be set at the highest price at which both of the conditions above

are satisfied, subject to the other provisions of this Section III.13.2. If it is not the case that both of the two conditions above are satisfied in the round, then the auctioneer shall publish the quantity of system-wide excess supply at the End-of-Round Price (the amount of capacity offered at the End-of-Round Price in all modeled Capacity Zones minus the Installed Capacity Requirement) and the quantity of excess supply in the export-constrained Capacity Zone (the amount of capacity offered at the End-of-Round Price in the export-constrained Capacity Zone minus the Maximum Capacity Limit of the export-constrained Capacity Zone) and the quantity of capacity from Demand Resources by type at the End-of-Round Price, and that Capacity Zone will be included in the next round of the Forward Capacity Auction.

(d) **Treatment of Import Capacity.** Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is less than or equal to that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offers from those resources shall be treated as capacity offers in the modeled Capacity Zone associated with that interface. Where the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between the New England Control Area and an external Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the following provisions shall apply (separately for each such interface):

(i) For purposes of determining which capacity offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface shall clear and at what price, the offers over the interface shall be treated in the descending-clock auction as if they comprised a separately-modeled export-constrained capacity zone, with an aggregate supply curve consisting of the offers from the New Import Capacity Resources and Existing Import Capacity Resources over the interface.

(ii) The amount of capacity offered over the interface that will be included in the aggregate supply curve of the modeled Capacity Zone associated with the interface shall be the lesser of the following two quantities: the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over the interface; and the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF).

(iii) The Forward Capacity Auction for New Import Capacity Resources and Existing Import Capacity Resources over the interface is concluded when the following two conditions are both satisfied: the amount of capacity offered from New Import Capacity Resource and Existing Import Capacity Resources over the interface is less than or equal to the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF); and the Forward Capacity Auction is concluded in the modeled Capacity Zone associated with the interface.

(e) **Treatment of Export Capacity.** Any Export Bid or any Administrative Export De-List Bid that is used to export capacity through an export interface connected to an import-constrained Capacity Zone from another Capacity Zone, or through an export interface connected to the Rest-of-Pool Capacity Zone from an export-constrained Capacity Zone in the Forward Capacity Auction will be modeled in the Capacity Zone where the export interface that is identified in the Existing Capacity Qualification Package is located. The Export Bid or Administrative Export De-List Bid clears against the Capacity Clearing Price in the Capacity Zone where the Export Bid or Administrative Export De-List Bid is modeled.

(i) Then the MW quantity equal to the relevant Export Bid or Administrative Export De-List Bid from the resource associated with the Export Bid or Administrative Export De-List Bid will be de-listed in the Capacity Zone where the resource is located. If the export interface is connected to an import-constrained Capacity Zone, the MW quantity procured will be in addition to the Local Sourcing Requirement of the import-constrained Capacity Zone.

(ii) If the Export Bid or Administrative Export De-List Bid does not clear, then the resource associated with the Export Bid or Administrative Export De-List Bid will not be de-listed in the Capacity Zone where the resource is located.

(f) **Treatment of Real-Time Emergency Generation Resources.** In determining when the Forward Capacity Auction is concluded, no more than 600 MW of capacity from Real-Time Emergency Generation Resources shall be counted towards meeting the Installed Capacity Requirement (net of HQICCs). If the sum of the Capacity Supply Obligations of Real-Time Emergency Generation Resources exceeds 600 MW, the Capacity Clearing Price, or in the case of Inadequate Supply or Insufficient Competition, the payment as described in Section III.13.2.8, (as adjusted pursuant to Section III.13.2.7.3(b)) paid to all Real-Time Emergency Generation Resources shall be adjusted by the ratio of 600 MW divided by the total of the final Capacity Supply Obligations of Real-Time Emergency

Generation Resources. The acceptance of a Real-Time Emergency Generation Resource Static De-list Bid, Dynamic De-list Bid, or Permanent De-list Bid shall be based on the effective Capacity Clearing Price as described in Section III.13.2.7.

III.13.2.3.4. Determination of Final Capacity Zones.

(a) For all Forward Capacity Auctions up to and including the sixth Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2015), after the Forward Capacity Auction is concluded for all modeled Capacity Zones, the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those having distinct Capacity Clearing Prices as a result of constraints between modeled Capacity Zones binding in the running of the Forward Capacity Auction. Where a modeled constraint does not bind in the Forward Capacity Auction, and as a result adjacent modeled Capacity Zones clear at the same Capacity Clearing Price, those modeled Capacity Zones shall be a single Capacity Zone used for all purposes of the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals.

(b) For all Forward Capacity Auctions beginning with the seventh Forward Capacity Auction (for the Capacity Commitment Period beginning June 1, 2016) the final set of distinct Capacity Zones that will be used for all purposes associated with the relevant Capacity Commitment Period, including for the purposes of reconfiguration auctions and Capacity Supply Obligation Bilaterals, shall be those described in Section III.12.4.

III.13.2.4. Forward Capacity Auction Starting Price.

The Forward Capacity Auction Starting Price for each Capacity Zone in the Forward Capacity Auction for the Capacity Commitment Period beginning on June 1, 2016 shall be $15/kW-month. Thereafter, the Forward Capacity Auction Starting Price will be adjusted after each Forward Capacity Auction using a rolling three-year average of the Handy-Whitman Index of Public Utility Construction Costs. References in this Section III.13 to the Forward Capacity Auction Starting Price shall mean the Forward Capacity Auction Starting Price for the Forward Capacity Auction associated with the relevant Capacity Commitment Period.

III.13.2.5. Treatment of Specific Offer and Bid Types in the Forward Capacity Auction.

III.13.2.5.1. Offers from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources.

A New Capacity Offer (other than one from a Conditional Qualified New Generating Capacity Resource) clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction if the Capacity Clearing Price is greater than or equal to the price specified in the offer, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. An offer from a Conditional Qualified New Generating Capacity Resource clears (receives a Capacity Supply Obligation for the associated Capacity Commitment Period) in the Forward Capacity Auction, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6, if all of the following conditions are met: (i) the Capacity Clearing Price is greater than or equal to the price specified in the offer; (ii) capacity from that resource is considered in the determination of clearing as described in Section III.13.2.3.2(f); and (iii) such offer minimizes the costs for the associated Capacity Commitment Period, subject to Section III.13.2.7.7(c).

The amount of capacity that receives a Capacity Supply Obligation through the Forward Capacity Auction shall not exceed the quantity of capacity offered from the New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource at the Capacity Clearing Price.

III.13.2.5.2. Bids and Offers from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources.

III.13.2.5.2.1. Permanent De-List Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Permanent De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.2. Static De-List Bids and Export Bids.

Except as provided in Section III.13.2.5.2.5 and Section III.13.2.5.2.7, a Static De-List Bid or an Export Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price

specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6.

III.13.2.5.2.3. Dynamic De-List Bids.

A Dynamic De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) if the Capacity Clearing Price is less than or equal to the price specified in the bid, except possibly as a result of the Capacity Rationing Rule described in Section III.13.2.6. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, such Dynamic De-List Bids shall be cleared pro-rata, but in no case less than a resource's Economic Minimum Limit.

III.13.2.5.2.4. Administrative Export De-List Bids.

An Administrative Export De-List Bid clears in the Forward Capacity Auction (does not receive a Capacity Supply Obligation for the associated Capacity Commitment Period) regardless of the Capacity Clearing Price and regardless of whether there is Inadequate Supply or Insufficient Competition in the Capacity Zone.

III.13.2.5.2.5. Bids Rejected for Reliability Reasons.

The ISO shall review each Non-Price Retirement Request, Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, and Dynamic De-List Bid entered into the Forward Capacity Auction to determine whether the capacity associated with that Non-Price Retirement Request or de-list bid is needed for reliability reasons during the Capacity Commitment Period associated with the Forward Capacity Auction. The capacity shall be deemed needed for reliability reasons if the absence of the capacity would result in the violation of any NERC or NPCC (or their successors) criteria, or ISO New England System Rules. Non-Price Retirement Requests and de-list bids shall not be rejected pursuant to this Section III.13.2.5.2.5 solely on the basis that acceptance of the Non-Price Retirement Request or de-list bid may result in the procurement of less capacity than the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement for Load Zones or aggregations of Load Zones considered for modeling in a Forward Capacity Auction. Where a Non-Price Retirement Request would otherwise be accepted, or a Permanent De-List Bid, Static De-List Bid, Export Bid, Administrative Export De-List Bid, or Dynamic De-List Bid would otherwise clear in the Forward Capacity Auction, but the ISO has determined that some or all of the capacity associated with the Non-Price Retirement Request or de-list bid is needed for reliability reasons, then the de-list bid having capacity needed for reliability

will not clear in the Forward Capacity Auction and the Non-Price Retirement Request will not be approved as described in Section III.13.1.2.3.1.5.3, and the following provisions will apply:

(a) The Lead Market Participant shall be notified that its de-list bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the de-list bid; or (ii) as soon as practicable after the time at which the ISO has determined that the de-list bid must be rejected for reliability reasons. In no event, however, shall a Lead Market Participant be notified that a bid submitted pursuant to Section III.13.1.2.5 and accepted in the qualification process for an Existing Generating Capacity Resource did not clear for reliability reasons if the associated New Generating Capacity Resource remains in the Forward Capacity Auction. In such a case, the Lead Market Participant shall be notified that its bid did not clear for reliability reasons at the later of: (i) immediately after the end of the Forward Capacity Auction round in which the auction price reaches the price of the bid; (ii) immediately after the end of the Forward Capacity Auction round in which the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity); or (iii) as soon as practicable after the time at which the ISO has determined that the bid must be rejected for reliability reasons.

(i) In the case of Non-Price Retirement Request, the Lead Market Participant will be notified whether or not the request has been rejected for reliability reasons within 90 days of the submission of the request.

(b) A resource that has a de-list bid rejected pursuant to this Section III.13.2.5.2.5 shall be compensated pursuant to the terms set out in Section III.13.2.5.2.5.1. An Existing Generating Capacity Resource or Existing Demand Resource that has a Non-Price Retirement Request rejected pursuant to this Section III.13.2.5.2.5 shall have the option to retire pursuant to Section III.2.5.2.5.3(a)(iii) or to continue operation and be compensated pursuant to Section III.13.2.5.2.5.1. A resource receiving payment under this Section III.13.2.5.2.5 and Section III.13.2.5.2.5.1 shall have the obligations of resources with Capacity Supply Obligations as described in Section III.13.6.1. Such resources shall be counted towards the Installed Capacity Requirement (net of HQICCs) for the Capacity Commitment Period.

(c) The ISO shall review the results of each annual reconfiguration auction and determine whether the reliability need which prevented the de-listing of the resource has been met through the annual

reconfiguration auction. The ISO may also attempt to address the reliability concern through other reasonable means (including transmission enhancements).

(d) If the reliability need that prevented the de-listing of the resource is met through a reconfiguration auction or other means, the resource shall be de-listed, be relieved of its Capacity Supply Obligation and no longer be eligible to receive the compensation specified in Section III.13.2.5.2.5(b). The ISO shall enter bids at the Forward Capacity Auction Starting Price to replace the capacity on behalf of load in subsequent annual reconfiguration auctions associated with the Capacity Commitment Period (and subsequent Capacity Commitment Periods, in the case of a Permanent De-List Bid).

(e) If a Permanent De-List Bid that would otherwise clear in a Forward Capacity Auction or a Non-Price Retirement Request is rejected for reliability reasons, that resource, or portion thereof, as applicable, is no longer eligible to participate as an Existing Generating Capacity Resource in any reconfiguration auction, Forward Capacity Auction or Capacity Supply Obligation Bilateral for that and subsequent Capacity Commitment Periods. If the resource, or portion thereof, continues to be needed for reliability reasons, it shall be counted as capacity in the Forward Capacity Auction and shall be compensated as described in Section III.13.2.5.2.5.1 until such time as it is no longer needed for reliability reasons.

(f) [Reserved.]

(g) The ISO shall review with the Reliability Committee (i) the status of any prior rejected delist bids reported to the Commission in an FCA results filing pursuant to Section 13.8.2, and (ii) the status of any Non-Price Retirement Request that has been rejected for reliability reasons and has elected to continue to operate, prior to the New Capacity Qualification Deadline in accordance with Section 4.1(c) of Attachment K of the ISO OATT.

In instances where an identified reliability need results in the rejection of a Non-Price Retirement Request, or the rejection of a Permanent De-List Bid, Export Bid, Administrative Export De-List Bid, Static De-List Bid, or Dynamic De-List Bid while executing an FCA, the ISO shall (i) review each specific reliability need with the Reliability Committee in accordance with the timing provided for in the ISO New England Operating Documents and, (ii) update the current system Needs Assessments pursuant to Section 4.1(c) of Attachment K of the ISO OATT. For de-list bids, this review and update will follow ISO's filing of the FCA results with the Commission pursuant to Section 13.8.2. System needs associated with Non-Price Retirement Requests that are rejected for reliability reasons will be reviewed with the

Reliability Committee prior to the notification of the Lead Market Participant that has submitted the Non-Price Retirement Request consistent with Section 13.2.5.2.5(a)(i).

III.13.2.5.2.5.1. Compensation for Bids Rejected for Reliability Reasons.

(a)(i) In cases where a Static De-List Bid, Export Bid, Administrative Export De-List Bid, Dynamic De-List Bid, or partial Permanent De-List Bid would otherwise clear in the Forward Capacity Auction but the de-list bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(a)(ii), the resource will be paid by the ISO in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price. Under this Section, accepted Dynamic De-list Bids filed with the Commission as part of the FCA results filing are subject to review and approval by the Commission pursuant to the "just and reasonable" standard of Section 205 of the Federal Power Act.

(a)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(a)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the de-list bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(a)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the de-list bid was rejected.

(b)(i) In cases where a Permanent De-List Bid for the capacity of an entire resource would otherwise clear in the Forward Capacity Auction but the Permanent De-List Bid has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource qualifies for payment under Section III.13.2.5.2.5.1(b)(ii), the resource will be paid either (i) in the same manner as all other capacity resources, except that payment shall be made on the basis of its de-list bid as accepted for the Forward Capacity Auction for the relevant Capacity Commitment Period instead of the Forward Capacity Market Clearing Price or (ii) under the terms of a cost-of-service agreement pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Permanent De-List Bid rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid on the basis of the resource's Permanent De-List Bid as accepted for the Forward Capacity Auction. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted the use of the cost-of-service rates subject to refund

while the rate is reviewed. In no event will payment under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Permanent De-List Bid was submitted. Resources that elect payment based on the accepted Permanent De-List Bid may file with the Commission pursuant to Section 205 of the Federal Power Act to update its Permanent De-List Bid if the unit is retained for reliability for a period longer than the Capacity Commitment Period for which the Permanent De-List Bid was originally submitted.

(b)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(b)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Permanent De-List Bid was rejected. Once qualified under this Section III.13.2.5.2.5.1(b)(ii), the resource will have a Capacity Supply Obligation for the 12-month Capacity Commitment Period for which the Permanent De-List Bid was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Permanent De-List Bid was rejected, payment pursuant to Section III.13.2.5.2.5.1(b)(i) will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(c)(i) In cases where a Non-Price Retirement Request for less than the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource will continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability. In cases where a Non-Price Retirement Request for the entire resource has been submitted and the request has been rejected for reliability reasons pursuant to Section III.13.2.5.2.5 and the resource has not elected to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), the resource may elect to either (i) continue to be paid in the same manner as other listed capacity resources until such time as the resource is no longer needed for reliability, or (ii) the resource may elect to receive cost-of-service compensation pursuant to Section III, Appendix I. Resources must notify the ISO of their election within six months after the ISO files the results of the relevant Forward Capacity Auction with the Commission. A resource that has had a Non-Price Retirement Request rejected for reliability reasons and does not notify the ISO of its election as described in this paragraph will be paid in the same manner as other listed capacity resources. Cost-of-service agreements must be filed with and approved by the Commission, and cost-of-service compensation may not commence until the Commission has approved the use of cost-of-service rates for the unit in question or has accepted subject to refund while the rate is reviewed. In no

event will compensation under the cost-of-service agreement start prior to the start of the relevant Capacity Commitment Period for which the Non-Price Retirement Request was rejected.

(c)(ii) A resource will qualify for payment under Section III.13.2.5.2.5.1(c)(i) if the ISO has not notified the resource that it is no longer needed for reliability reasons by 12:00 a.m. on June 1 of the year preceding the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request was rejected. Once qualified under this Section III.13.2.5.2.5.1(c)(ii), compensation will be provided for the 12-month Capacity Commitment Period for which the Non-Price Retirement Request was rejected. If a resource continues to be needed for reliability in Capacity Commitment Periods following the Capacity Commitment Period for which the Non-Price Retirement Request was rejected, payment pursuant to Section III.13.2.5.2.5.1 will continue and will terminate upon 120 day notice from the ISO to the resource that it is no longer needed for reliability.

(d) The difference between payments based on resource de-list bids or cost-of-service compensation as detailed in this Section III.13.2.5.2.5.1 and payments based on the market clearing price for the Forward Capacity Market under this Section III.13.2.5.2.5.1 shall be allocated to Regional Network Load within the affected Reliability Region.

(e) **Compensation for Existing Generating Capacity Resources at Stations with Common Costs that are Retained for Reliability**. If a Static De-List Bid or Permanent De-List Bid from an Existing Generating Capacity Resource that is associated with a Station having Common Costs is rejected for reliability reasons, the Existing Generating Capacity Resource will be paid as follows: (i) if one or more Existing Generating Capacity Resources at the Station assume a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then the Existing Generating Capacity Resources retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets comprising that Existing Generating Capacity Resource; or (ii) if no Existing Generating Capacity Resources at the Station assumes a Capacity Supply Obligation through the normal clearing of the Forward Capacity Auction and one or more Existing Generating Capacity Resources are retained for reliability, then each Existing Generating Capacity Resource retained for reliability will be paid the sum of the Asset-Specific Going Forward Costs for the assets associated with that Existing Generating Capacity Resource plus a portion of the Station Going Forward Common Costs (such that the full amount of Station Going Forward Common Costs are allocated to the Existing Generating Capacity Resources retained for reliability).

III.13.2.5.2.5.2. Incremental Cost of Reliability Service From Non-Price Retirement Request Resources:

In cases where an Existing Generating Capacity Resource or Existing Demand Resource has had a Non-Price Retirement Request for the entire resource rejected for reliability reasons pursuant to Section III.13.2.5.2.5, does not elect to retire pursuant to Section III.13.2.5.2.5.3(a)(iii), and must make a capital improvement to the unit to remain in operation in order to continue to operate to meet the reliability need identified by the ISO, the resource may make application to the Commission pursuant to Section 205 of the Federal Power Act to receive just and reasonable compensation of the capital investment pursuant to the following:

(a) **Notice to State Utility Commissions, the ISO and Stakeholder Committees of Expectation that a Capital Expense will be Necessary to Meet the Reliability Need Identified by ISO New England**: A resource seeking to avail itself of the recovery mechanism provided in this Section must notify the state utility commissions in the states where rate payers will fund the capital improvement, the ISO, and the Participants Committee of its intent to make the capital expenditure and the need for the expenditure. This notification must be made at least 120 days prior to the resource making the capital expenditure.

(b) **Required Showing Made to the Federal Energy Regulatory Commission**: In order to receive just and reasonable compensation for a capital expenditure under this Section, a resource must file an explanation of need with the Commission that explains why the capital expenditure is necessary in order to meet the reliability need identified by the ISO. This showing must demonstrate that the expenditure is reasonably determined to be the least-cost commercially reasonable option consistent with Good Utility Practice to meet the reliability need identified by the ISO. If the resource elects cost-of-service treatment pursuant to Section III.13.2.5.2.5.1(c), the Incremental Cost of Reliability Service filing described in this Section must be made separately from and may be made in advance of the resource's cost-of-service filing.

(c) **Allocation:** Costs of capital expenditures approved by the Commission under this provision shall be allocated to Regional Network Load within the affected Reliability Region.

III.13.2.5.2.5.3. Retirement of Resources

(a)(i) A resource, or portion thereof, that submits a Non-Price Retirement Request pursuant to Section III.13.1.2.3.1.5 will be retired coincident with the commencement of the Capacity Commitment Period for

which the Non-Price Retirement Request is submitted if the request is approved, or if not approved the resource nonetheless elects to retire pursuant to Section III.13.2.5.2.5.3(a)(iii). If the Non-Price Retirement Request is approved after the resource has a Capacity Supply Obligation for the Capacity Commitment Period for which the Non-Price Retirement Request was submitted, the resource, or portion thereof, will be retired coincident with the end of Capacity Supply Obligation under Section III.13.2.5.2.5.1(c)(ii). The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(ii) An Existing Generating Capacity Resource or Existing Demand Resource with an approved Non-Price Retirement Request may retire the resource, or portion thereof, earlier than the Capacity Commitment Period for which its Non-Price Retirement Request has been approved if it is able to transfer the relevant Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4.1. A resource, or portion thereof, electing to retire pursuant to this provision must notify the ISO in writing of its election to retire and the date of retirement. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(a)(iii) In cases where an Existing Generating Capacity Resource or Existing Demand Resource has submitted a Non-Price Retirement Request and the request is not approved because the resource is determined to be needed for reliability pursuant to Section III.13.2.5.2.5, the portion of the resource subject to the Non-Price Retirement Request may nonetheless retire as permitted by applicable law coincident with the commencement of the Capacity Commitment Period for which the Non-Price Retirement Request is submitted by notifying ISO within six months of receiving the notice from the ISO that the Non-Price Retirement Request has not been approved for reliability reasons. Such an election will be binding. A resource making an election pursuant to this Section III.13.2.5.2.5.3(a)(iii) will not be eligible for compensation pursuant to Sections III.13.2.5.2.5.1 or III.13.2.5.2.5.2. The interconnection rights, or relevant portion thereof, for the resource will terminate and the status of the resource, or portion thereof, will be converted to retired on the date of retirement, consistent with the provisions of Schedules 22 and 23 of the OATT.

(b)(i) A resource that has submitted a non-partial Permanent De-List Bid that has cleared in the Forward Capacity Auction may retire the resource as of the Capacity Commitment Period for which its Permanent De-List Bid has cleared or earlier as described in Section III.13.2.5.2.5.3(b)(ii) by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(b)(ii) A resource with a cleared non-partial Permanent De-List Bid may retire the resource earlier than the Capacity Commitment Period for which its Permanent De-List Bid has cleared if it is able to transfer the entire Capacity Supply Obligation of the resource to another resource through one or more approved Capacity Supply Obligation Bilateral transactions as described in Section III.13.5.1 or reconfiguration auctions as described in Section III.13.4. A resource electing to retire pursuant to this provision must notify ISO in writing of its election to retire and the date of retirement. The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date on retirement.

(c) A resource that has never been counted as a capacity resource may retire the asset by notifying the ISO in writing of its election to retire and the date of retirement. The date specified for retirement is subject to the limit for resource inactivity set out in Section III.13.2.5.2.5.3(d). The interconnection rights for the resource will terminate and the status of the resource will be converted to retired on the date of retirement.

(d) A resource that does not operate commercially for a period of three calendar years will be deemed by the ISO to be retired. The interconnection rights for the unit will terminate and the status of the unit will be converted to retired on the date of retirement. Where a generator has submitted an application to repower under Schedule 22 or 23 of the OATT, the current interconnection space will be maintained beyond the three years unless the application under Schedule 22 or 23 is withdrawn voluntarily or by the operation of those provisions. Where an application is withdrawn under Schedule 22 or 23, the three year period will be calculated from the last day of commercial operation of the resource.

III.13.2.5.2.6. [Reserved.]

III.13.2.5.2.7. Treatment of De-List and Export Bids When the Capacity Clearing Price is Set Administratively.

Where the Capacity Clearing Price is set pursuant to Section III.13.2.8 (Inadequate Supply and Insufficient Competition), and as a result a Permanent De-List Bid, Static De-List Bid, or Export Bid clears that would not otherwise have cleared, then the de-listed or exported capacity will not be replaced in the current Forward Capacity Auction (that is, the amount of capacity procured in the Forward Capacity Auction shall be the Installed Capacity Requirement (net of HQICCs) or Local Sourcing Requirement, as appropriate, minus the amount of the de-listed or exported capacity that results from the application of administratively determined prices) and shall be included in subsequent annual reconfiguration auctions (that is, the amount of capacity procured in subsequent annual reconfiguration auctions shall be increased by the amount of the de-listed or exported capacity).

III.13.2.6. Capacity Rationing Rule.

Except for Dynamic De-List Bids, Export Bids, and offers from New Import Capacity Resources and Existing Import Capacity Resources, offers and bids in the Forward Capacity Auction must clear or not clear in whole, unless the offer or bid specifically indicates that it may be rationed. A resource may elect to be rationed to either its Economic Minimum Limit or a level above its Economic Minimum Limit. These levels are submitted pursuant to Section III.13.1.1.2.2.3. Offers from New Import Capacity Resources and Existing Import Capacity Resources are subject to rationing, except where such rationing would violate any applicable physical minimum flow requirements on the associated interface. Export Bids may elect to be rationed generally, but regardless of such election will always be subject to potential rationing where the associated external interface binds. If more Dynamic De-List Bids are submitted at a price than are needed to clear the market, the bids shall be cleared pro-rata, subject to honoring the Economic Minimum Limit of the resources. Where an offer or bid may be rationed, such rationing may not result in procuring an amount of capacity that is below the associated resource's Economic Minimum Limit.

III.13.2.7. Determination of Capacity Clearing Prices.

The Capacity Clearing Price in each Capacity Zone shall be the price established by the descending clock Forward Capacity Auction as described in Section III.13.2.3, subject to the other provisions of this Section III.13.2.

III.13.2.7.1. Import-Constrained Capacity Zone Capacity Clearing Price Floor.

The Capacity Clearing Price in an import-constrained Capacity Zone shall not be lower than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an import-constrained Capacity Zone is less than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the import-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.2. Export-Constrained Capacity Zone Capacity Clearing Price Ceiling.

The Capacity Clearing Price in an export-constrained Capacity Zone shall not be higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone. If after the Forward Capacity Auction is conducted, the Capacity Clearing Price in an export-constrained Capacity Zone is higher than the Capacity Clearing Price in the Rest-of-Pool Capacity Zone, all resources clearing in the export-constrained Capacity Zone shall be paid based on the Capacity Clearing Price in the Rest-of-Pool Capacity Zone during the associated Capacity Commitment Period.

III.13.2.7.3. Capacity Clearing Price Floor.

In the Forward Capacity Auctions for the Capacity Commitment Periods beginning on June 1, 2013, June 1, 2014, June 1, 2015, and June 1, 2016 only, the following additional provisions regarding the Capacity Clearing Price shall apply in all Capacity Zones (and in the application of Section III.13.2.3.3(d)(iii)):

(a) [Reserved.]

(b) The Capacity Clearing Price shall not fall below 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 below $3.15). Where the Capacity Clearing Price reaches 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 reaches $3.15), offers shall be prorated such that no more than the Installed Capacity Requirement (net of HQICCs) is procured in the Forward Capacity Auction, as follows:

(i) The total payment to all listed capacity resources during the associated Capacity Commitment Period shall be equal to 0.6 times CONE (or in the case of the Forward Capacity Auction for the Capacity Commitment Period beginning June 1, 2016 shall be equal to $3.15) times the Installed Capacity Requirement (net of HQICCs) applicable in the Forward Capacity Auction.

(ii) Payments to individual listed resources shall be prorated based on the total number of MWs of capacity clearing in the Forward Capacity Auction (receiving a Capacity Supply Obligation for the associated Capacity Commitment Period).

(iii) Suppliers may instead prorate their bid MWs of participation in the Forward Capacity Market by partially de-listing one or more resources. Regardless of any such proration, the full amount of capacity that cleared in the Forward Capacity Auction will be ineligible for treatment as new capacity in subsequent Forward Capacity Auctions (except as provided under Section III.13.1.1.1.2).

(iv) Any proration shall be subject to reliability review. Where proration is rejected for reliability reasons, the resource's payment shall not be prorated as described in subsection (ii) above, and the difference between its actual payment based on the Capacity Clearing Price and what its payment would have been had prorationing not been rejected for reliability reasons shall be allocated to Regional Network Load within the affected Reliability Region. In this case, the total payment described in subsection (i) above will increase accordingly.

(v) Any election to prorate bid MWs associated with a New Capacity Offer that clears in the Forward Capacity Auction shall also apply in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5.

III.13.2.7.3A Treatment of Imports.

At the Capacity Clearing Price, if the amount of capacity offered from New Import Capacity Resources and Existing Import Capacity Resources over an interface between an external Control Area and the New England Control Area is greater than that interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF):

(a) the full amount of capacity offered at that price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall clear, unless that amount of capacity is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), in which case the capacity offered at that

price from Existing Import Capacity Resources associated with contracts listed in Section III.13.1.3.3(c) shall be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded; and

(b) if there is space remaining over the interface after the allocation described in subsection (a) above, then the capacity offered at that price from New Import Capacity Resources and Existing Import Capacity Resources other than Existing Import Capacity Resources associated with the contracts listed in Section III.13.1.3.3(c) will be rationed such that the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) is not exceeded. If the capacity offered at that price by any single New Import Capacity Resource or Existing Import Capacity Resource that is not associated with the contracts listed in Section III.13.1.3.3(c) is greater than the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF), then the capacity offered by that resource that is above the interface's approved capacity transfer limit (net of tie benefits, or net of HQICC in the case of the Phase I/II HVDC-TF) shall not be included in the rationing.

III.13.2.7.4. Effect of Capacity Rationing Rule on Capacity Clearing Price.

Where the requirement that offers and bids clear or not clear in whole (Section III.13.2.6) prohibits the descending clock auction in its normal progression from clearing a Capacity Zone at the precise amount of capacity required, then the auctioneer shall analyze the aggregate supply curve to determine cleared capacity offers and Capacity Clearing Prices that result in procuring at least the amount of capacity required while seeking to maximize social surplus for the associated Capacity Commitment Period. In an import-constrained Capacity Zone, the clearing algorithm will not consider blocks of capacity not needed to meet the import-constrained Capacity Zone's Local Sourcing Requirement when price separation occurs between the import-constrained Capacity Zone and the Rest-of-Pool Capacity Zone. The clearing algorithm may result in offers below the Capacity Clearing Price not clearing, and in de-list bids below the Capacity Clearing Price clearing.

III.13.2.7.5. Effect of Decremental Repowerings on the Capacity Clearing Price.

Where the effect of accounting for certain repowering offers and bids (as described in Section III.13.2.3.2(e)) results in the auction not clearing at the lowest price for the required quantity of capacity, then the auctioneer will conduct additional auction rounds of the Forward Capacity Auction as necessary to minimize capacity costs.

III.13.2.7.6. Minimum Capacity Award.

Each offer (excluding offers from Conditional Qualified New Generating Capacity Resources that do not satisfy the conditions specified in Sections III.13.2.5.1(i)-(iii)) clearing in the Forward Capacity Auction shall be awarded a Capacity Supply Obligation at least as great as the amount of capacity offered at the End-of-Round Price in the final round of the Forward Capacity Auction. For Intermittent Power Resources and Intermittent Settlement Only Resources, the Capacity Supply Obligation for months in the winter period (as described in Section III.13.1.5) shall be adjusted based on its winter Qualified Capacity as determined pursuant to Section III.13.1.1.2.2.6 and Section III.13.1.2.2.2.

III.13.2.7.7. Tie-Breaking Rules.

Where the provisions in this Section III.13.2 for clearing the Forward Capacity Auction (system-wide or in a single Capacity Zone) result in a tie – that is, where two or more resources offer sufficient capacity at prices that would clear the auction at the same minimum costs – the auctioneer shall apply the following rules (in sequence, as necessary) to determine clearing:

(a) The auctioneer shall clear the resources in such a manner as to maximize the total amount of capacity procured.

(b) If multiple projects may be rationed, they will be rationed proportionately.

(c) Where clearing either the offer associated with a resource with a higher queue priority at a Conditional Qualified New Generating Capacity Resource's location or the offer associated with the Conditional Qualified New Generating Capacity Resource would result in equal costs, the offer associated with the resource with the higher queue priority shall clear.

(d) The offer associated with the Project Sponsor having the lower market share in the capacity auction (including Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources) shall be cleared.

III.13.2.7.8. [Reserved.]

III.13.2.7.9 Capacity Carry Forward Rule.

III.13.2.7.9.1. Trigger.

The capacity carry forward rule shall be triggered in an import-constrained Capacity Zone if all of the following conditions are met:

(a) the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction in the Capacity Zone is less than or equal to zero;

(b) there is not Inadequate Supply in the Forward Capacity Auction in the Capacity Zone; and

(c) at the Capacity Clearing Price, the sum of the amount of New Capacity Required plus the amount of Permanent De-List Bids clearing in the Forward Capacity Auction plus the amount of capacity carried forward due to rationing is greater than zero. The amount of capacity carried forward due to rationing shall equal the amount of capacity above the Local Sourcing Requirement procured in that Capacity Zone in the previous Forward Capacity Auction as a result of the Capacity Rationing Rule.

III.13.2.7.9.2. Pricing.

If the capacity carry forward rule is triggered, then the Capacity Clearing Price for the Capacity Zone shall be the lesser of: (1) $0.01 below the price at which the last New Generating Capacity Resource, New Import Capacity Resource, or New Demand Resource in the Capacity Zone to withdraw withdrew from the Forward Capacity Auction; or (2) the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1; provided, however, that if in the Capacity Zone there is Insufficient Competition and no capacity offered from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources has been withdrawn from the Forward Capacity Auction, then the Capacity Clearing Price shall equal the Offer Review Trigger Price for a combustion turbine, as set forth in Section III.A.21.1.1.

III.13.2.8. Inadequate Supply and Insufficient Competition.

In the case of either Inadequate Supply or Insufficient Competition, as defined in this Section III.13.2.8, the Forward Capacity Auction shall still be used to the extent possible; that is, the remedy for Inadequate Supply or Insufficient Competition shall be limited to the Capacity Zones having Inadequate Supply or Insufficient Competition.

III.13.2.8.1. Inadequate Supply.

III.13.2.8.1.1. Inadequate Supply in an Import-Constrained Capacity Zone.

An import-constrained Capacity Zone will be considered to have Inadequate Supply if at the Forward Capacity Auction Starting Price the amount of capacity offered in the import-constrained Capacity Zone through New Capacity Offers is less than the amount of New Capacity Required in that Capacity Zone. In an import-constrained Capacity Zone, "New Capacity Required" shall mean the Capacity Zone's Local Sourcing Requirement, minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Capacity Zone for the Capacity Commitment Period; in the Rest-of-Pool Capacity Zone, "New Capacity Required" shall mean the Installed Capacity Requirement (net of HQICCs), minus the Local Sourcing Requirement of each modeled import-constrained Capacity Zone, minus, for each modeled export-constrained Capacity Zone, the lesser of the Capacity Zone's Maximum Capacity Limit or the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus the total amount of capacity of Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone (that is not permanently de-listed for the Capacity Commitment Period), minus capacity otherwise obligated in the Rest-of-Pool Capacity Zone for the Capacity Commitment Period.

(a) Where an import-constrained Capacity Zone has Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) in that Capacity Zone, other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction in that Capacity Zone shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In an import-constrained Capacity Zone having Inadequate Supply, the difference between the amount of capacity offered in the Capacity Zone through New Capacity Offers and the amount of New Capacity Required in that Capacity Zone shall be included in subsequent annual reconfiguration auctions.

(c) Inadequate Supply in one or more import-constrained Capacity Zones shall not affect Capacity Zones having adequate supply.

(d) Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Inadequate Supply will be assessed at a rate equal to 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

III.13.2.8.1.2. System-Wide Inadequate Supply.

The New England Control Area will be considered to have system-wide Inadequate Supply if at the Forward Capacity Auction Starting Prices, the total amount of capacity offered in the Forward Capacity Auction is less than the Installed Capacity Requirement (net of HQICCs).

(a) In the case of system-wide Inadequate Supply, Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, shall be paid 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply during the associated Capacity Commitment Period, and New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources in the Forward Capacity Auction shall be paid the Forward Capacity Auction Starting Price during the associated Capacity Commitment Period (and subsequent Capacity Commitment Periods, as elected pursuant to Section III.13.1.1.2.2.4 or Section III.13.1.4.2.2.5).

(b) In the case of system-wide Inadequate Supply, the difference between the total amount of capacity offered in the Forward Capacity Auction and the Installed Capacity Requirement (net of HQICCs) shall be included in subsequent annual reconfiguration auctions.

(c) System-wide Inadequate Supply will not affect the Forward Capacity Auction in Capacity Zones having adequate supply, except that in those Capacity Zones having adequate supply, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the

Capacity Clearing Price, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources other than such resources, or portions thereof, that have no Capacity Supply Obligation or are designated as Self-Supplied FCA Resources for the Capacity Commitment Period, will be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply.

(d) If there is system-wide Inadequate Supply, but the amount of capacity offered in an export-constrained Capacity Zone, including imports as appropriate, is greater than the Maximum Capacity Limit in that export-constrained Capacity Zone, the Forward Capacity Auction in the export-constrained Capacity Zone shall be unaffected, and in that case the price paid to Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Rest-of-Pool Capacity Zone shall be the higher of: (1) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Inadequate Supply; or (2) the price in the export-constrained Capacity Zone.

III.13.2.8.2. Insufficient Competition.

The Forward Capacity Auction shall be considered to have Insufficient Competition system-wide or in any import-constrained Capacity Zone if the following two conditions are both satisfied:

(a) at the Forward Capacity Auction Starting Price, the amount of capacity offered from Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources is less than the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable; and

(b) at the Forward Capacity Auction Starting Price:

(i) less than 300 MW of capacity is offered from New Generating Capacity Resources and New Demand Resources (the ISO shall revisit the appropriateness of the 300 MW threshold in the case of an import-constrained Capacity Zone having a Local Sourcing Requirement of less than 5000 MW);

(ii) the amount of capacity offered from New Generating Capacity Resources and New Demand Resources is more than the amount of New Capacity Required but less than twice the amount of New Capacity Required; or

(iii) any Market Participant's total capacity from New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources is pivotal. A Market Participant shall be considered pivotal if, at the Forward Capacity Auction Starting Price, some capacity from that Market Participant's potential New Generating Capacity Resources, New Import Capacity Resources, or New Demand Resources is required to satisfy the Installed Capacity Requirement (net of HQICCs) or the Local Sourcing Requirement, as applicable.

If the Forward Capacity Auction has Insufficient Competition, New Generating Capacity Resources, New Import Capacity Resources, and New Demand Resources shall be paid the Capacity Clearing Price during the associated Capacity Commitment Period, and Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources (other than those still subject to a multi-year Capacity Commitment Period election as described in Sections III.13.1.1.2.2.4 and III.13.1.4.2.2.5) shall be paid the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition during the associated Capacity Commitment Period. Any availability penalty assessed during the associated Capacity Commitment Period pursuant to Section III.13.7.2.7.1.2 on a resource in an import-constrained Capacity Zone having Insufficient Competition will be assessed at a rate equal to the lower of: (1) the Capacity Clearing Price; or (2) 1.1 times the Capacity Clearing Price for the most recent Forward Capacity Auction not having Insufficient Competition.

III.13.2.9. [Reserved.]

III.13.8. Reporting and Price Finality

III.13.8.1. Filing of Certain Determinations Made By the ISO Prior to the Forward Capacity Auction and Challenges Thereto

(a) For each Forward Capacity Auction, no later than 90 days prior to the first day of the auction, the ISO shall make an informational filing with the Commission detailing the following determinations made by the ISO with respect to that Forward Capacity Auction, and providing supporting documentation for each such determination, provided, however, that the determinations in subsections (vi), (vii), and (viii) below shall be filed confidentially with the Commission in the informational filing, except determinations on which new resources have been rejected due to overlapping interconnection impacts (the determinations in subsections (vi), (vii), and (viii) shall be published by the ISO no later than 15 days after the Forward Capacity Auction):

(i) which Capacity Zones shall be modeled in the Forward Capacity Auction;

(ii) the transmission interface limits as determined pursuant to Section III.12.5;

(iii) which existing and proposed transmission lines the ISO determines will be in service by the start of the Capacity Commitment Period associated with the Forward Capacity Auction;

(iv) the expected amount of installed capacity in each modeled Capacity Zone during the Capacity Commitment Period associated with the Forward Capacity Auction, and the Local Sourcing Requirement for each modeled import-constrained Capacity Zone and the Maximum Capacity Limit for each modeled export-constrained Capacity Zone;

(v) the multipliers applied in determining the Capacity Value of a Demand Resource, as described in Section III.13.7.1.5.1;

(vi) which new resources are accepted and rejected in the qualification process to participate in the Forward Capacity Auction;

(vii) the Internal Market Monitor's determinations regarding each requested offer price from a new resource submitted pursuant to Section III.13.1.1.2.2.3 or Section III.13.1.4.2, including information regarding each of the elements considered in the Internal Market Monitor's

determination of expected net revenues (other than revenues from ISO-administered markets) and whether that element was included or excluded in the determination of whether the offer is consistent with the resource's long run average costs net of expected net revenues other than capacity revenues;

(viii) the Internal Market Monitor's determinations regarding offers or bids submitted during the qualification process made according to the provisions of this Section III.13, including an explanation of the reasons for rejecting any de-list bids based on the Internal Market Monitor review and the resource's net risk-adjusted going forward costs and opportunity costs as determined by the Internal Market Monitor. The filing shall identify to the extent possible the components of the bid which were accepted as justified, and shall also identify to the extent possible the components of the bid which were not justified and which resulted in rejection of the bid;

(ix) which existing resources are qualified to participate in the Forward Capacity Auction (this information will include resource type, capacity zone, and qualified MW); and

(x) aggregate MW from new resources qualified to participate in the Forward Capacity Auction and aggregate de-list bid amounts.

(b) Any comments or challenges to the determinations contained in the informational filing described in Section III.13.8.1(a) or in the qualification determination notifications described in Sections III.13.1.1.2.8, III.13.1.2.4, and III.13.1.3.5.7, and any election made pursuant to Section III.13.1.2.3.2.1.1.1, must be filed with the Commission no later than 15 days after the ISO's submission of the informational filing. If the Commission does not issue an order within 75 days after the ISO's submission of the informational filing that directs otherwise, the determinations contained in the informational filing and elections made pursuant to Section III.13.1.2.3.2.1.1 shall be used in conducting the Forward Capacity Auction, and challenges to Capacity Clearing Prices resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c). If within 75 days after the ISO's submission of the informational filing, the Commission does issue an order modifying one or more of the ISO's determinations, then the Forward Capacity Auction shall be conducted no earlier than 15 days following that order using the determinations as modified by the Commission (unless the Commission directs otherwise), and challenges to Capacity Clearing Prices

resulting from the Forward Capacity Auction shall be reviewed in accordance with the provisions of Section III.13.8.2(c).

III.13.8.2. Filing of Forward Capacity Auction Results and Challenges Thereto.

(a) As soon as practicable after the Forward Capacity Auction is complete, the ISO shall file the results of that Forward Capacity Auction with the Commission pursuant to Section 205 of the Federal Power Act, including the final set of Capacity Zones resulting from the auction, the Capacity Clearing Price in each of those Capacity Zones (and the Capacity Clearing Price associated with certain imports pursuant to Section III.13.2.3.3(d), if applicable), and a list of which resources received Capacity Supply Obligations in each Capacity Zone and the amount of those Capacity Supply Obligations. Upon completion of the fourth and future auctions, such list of resources that receive Capacity Supply Obligation shall also specify which resources cleared as Conditional Qualified New Generating Capacity Resources. Upon completion of the fourth and future auctions, the filing shall also list each Long Lead Time Generating Facility, as defined in Schedule 22 of Section II of the Transmission, Markets and Services Tariff, that secured a Queue Position to participate as a New Generating Capacity Resource in the Forward Capacity Auction and each resource with lower queue priority that was selected in the Forward Capacity Auction subject to a Long Lead Time Generating Facility with the higher queue priority. The filing shall also enumerate bids rejected for reliability reasons pursuant to Section III.13.2.5.2.5, and the reasons for those rejections.

(b) The filing of Forward Capacity Auction results made pursuant to this Section III.13.8.2 shall also include documentation regarding the competitiveness of the Forward Capacity Auction, which may include a certification from the auctioneer and the ISO that: (i) all entities offering and bidding in the Forward Capacity Auction were properly qualified in accordance with the provisions of Section III.13.1; and (ii) the Forward Capacity Auction was conducted in accordance with the provisions of Section III.13.

(c) Any objection to the Forward Capacity Auction results must be filed with the Commission within 45 days after the ISO's filing of the Forward Capacity Auction results. The filing of a timely objection with the Commission will be the exclusive means of challenging the Forward Capacity Auction results.

(d) Any change to the Transmission, Markets and Services Tariff affecting the Forward Capacity Market or the Forward Capacity Auction that is filed after the results of a Forward Capacity Auction have been accepted or approved by the Commission shall not affect those Forward Capacity Auction results.

III.13.8.3. **[Reserved.]**

III.13.8.4. **[Reserved.]**