September 24, 2015

BY 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,***
Docket No. ER15-____-000; Revisions to Fast-Start Resource Pricing and Dispatch

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act,[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee (together, the "Filing Parties"),[2] hereby submit this transmittal letter and revisions to the ISO's Transmission, Markets and Services Tariff (the "Tariff")[3] to improve real-time price formation when fast-start resources are deployed. As discussed below, these Tariff changes were broadly supported by stakeholders. In support of these Tariff changes, the ISO is submitting the testimony of Matthew White, the ISO's Chief Economist (the "White Testimony"). The White Testimony is sponsored solely by the ISO. The ISO respectfully requests an effective date of March 31, 2017 and that the Federal Energy Regulatory Commission (the "Commission") **issue an order accepting these Tariff revisions no later than December 15, 2015.**

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

[2] Under New England's RTO arrangements, the ISO has the rights to make this filing of changes to the Tariff under Section 205 of the Federal Power Act. NEPOOL, which pursuant to the Participants Agreement provides the sole Market Participant stakeholder process for advisory voting on ISO matters, supported the changes reflected in this filing and accordingly, joins in this Section 205 filing.

[3] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the Tariff, the Second Restated New England Power Pool Agreement, and the Participants Agreement.

I. REQUESTED EFFECTIVE DATE, REQUEST FOR WAIVER, AND REQUEST FOR COMMISSION ORDER

The ISO requests that the Commission accept these Tariff changes as filed, without suspension or hearing, to be effective on March 31, 2017. Pursuant to Section 35.3(a)(1) of the Commission's Rules of Practice and Procedure, Tariff revisions such as those presented here must be filed with the Commission "not less than sixty days nor more than one hundred twenty days prior to the date on which the electric service is to commence and become effective."[4] Because the requested effective date of March 31, 2017 is more than 120 days after the date of this filing, the ISO respectfully requests waiver of this requirement of Section 35.3(a)(1).

Good cause exists to permit such a waiver because the changes filed here require a significant investment in software development, testing, and integration. This process requires a substantial amount of time between a Commission order and the implementation date, and the effort will only be undertaken with Commission approval. Moreover, these changes must be sequenced with several other intensive software projects (such as "do not exceed" dispatch for Intermittent Power Resources and sub-hourly real-time market settlements), which present numerous interdependencies and rely on the same ISO personnel and software vendor for implementation. For these reasons, and because the ISO does not believe that any party will be prejudiced by the additional notice time, the Commission should permit these Tariff changes to become effective on March 31, 2017.

For similar reasons, the ISO respectfully requests that the Commission issue an order on these Tariff changes no later than December 15, 2015. This date will provide ample time for any responsive pleadings in this proceeding and for the Commission's consideration, while providing the ISO with the necessary lead-time to schedule internal resources and to obtain the specialized vendor-supplied software upgrades that will enable completion of these fast-start pricing improvements by the requested effective date.

II. DESCRIPTION OF THE FILING PARTIES; 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").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 440 members. The Participants

[4] 18 C.F.R. § 35.3(a)(1) (2015).

include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[5] 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 provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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

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[5] *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

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

III. STANDARD OF REVIEW

These changes are being submitted pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[7] 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 accept this Section 205 filing if it is just and reasonable.[12]

IV. EXPLANATION OF THE CHANGES

The term "fast-start" generally describes resources that can be started in thirty minutes or less, that have a minimum run time of one hour or less, and that have a minimum down time of one hour or less. These general criteria are met by Fast Start Generators, Flexible DNE Dispatchable Generators,[13] Fast Start Demand Response Resources, and certain Dispatchable Asset Related Demand resources, though each of these resource types may have additional requirements specified in the Tariff.[14] Resources meeting these criteria play an important role in operating the system efficiently and reliably. They allow the ISO to respond quickly and reliably to unanticipated system conditions, help to satisfy peak loads on the power system, and provide essential operating reserves when offline.[15]

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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) ("*Bethany*").

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

12 *Cf. Southern California Edison Co., et al,* 73 FERC ¶ 61,219 at p. 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 The term "Flexible DNE Dispatchable Generator" will become effective in the Tariff in April 2016 pursuant to *ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,065 (July 23, 2015).

14 *See* Tariff Section I.2.2.

15 *See* White Testimony at 3.

As explained in the White Testimony, there are two significant problems with the current pricing and dispatch method when fast-start resources are deployed.[16] First, these valuable (and generally high-cost) resources typically do not set the real-time energy market price, even though they are routinely committed and dispatched, in least-cost manner, to meet demand and ensure reliable operation of the power system. As a result, the market's real-time price signals often fail to reflect the costs of operating these resources, and fast-start resources frequently must rely on uplift payments to cover their operating costs (as offered). As Dr. White notes,[17] this problem was identified by the ISO's External Market Monitor, Potomac Economics, in its 2013 Assessment of the ISO New England Electricity Markets,[18] which stated that:

> [f]ast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2013, 60 percent of the fast-start capacity that was started in the real-time market did not recoup its offer. This leads fast-start resources with flexible characteristics to be substantially under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits.[19]

The External Market Monitor recommended that "the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices."[20]

Second, when a fast-start resource is initially committed, the current fast-start logic may yield a dispatch solution with a small amount of system-wide over-generation. Although the period in which this occurs is not long (as it is associated with only the initial commitment interval), it can require "regulation down" service by other generators on Automatic Generation Control to offset the effect of the imbalanced power system dispatch. From an economic perspective, this unnecessary use of Automatic Generation Control service may have a greater cost than would occur with a more efficient fast-start dispatch and pricing method that avoids this over-generation instruction problem.[21]

These problems stem from the fact that fast-start resources are "lumpy" by nature. Fast-start resources are generally inflexible in that they typically operate inefficiently at less than their maximum output, or may not be able to physically operate much below their maximum output.

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[16] *See* White Testimony at 9-10.

[17] *See* White Testimony at 10-11.

[18] *See* Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, June 2014, available at http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf ("2013 Market Assessment").

[19] 2013 Market Assessment at p. 22.

[20] *Id*.

[21] *See* White Testimony at 10.

For this reason, the energy supply offer parameters of these resources may stipulate that they be dispatched either to zero output, or to a minimum level that is at (or close to) their maximum output, but not in between.[22] Because of their ability to start quickly, these resources are often the ones called on to meet sudden changes in demand, but their "lumpiness" imposes significant challenges to both dispatch and pricing.

To address these problems, the ISO is making four changes to dispatch, pricing, and compensation when fast-start resources are committed and dispatched:

(1) adjusting the real-time dispatch process to satisfy the offered minimum output level of each committed fast-start resource during its initial commitment interval;

(2) "relaxing" a pool-committed fast-start resource's minimum output to zero in the pricing process that calculates real-time Locational Marginal Prices ("LMPs") and Reserve Market Clearing Prices ("RMCPs");

(3) revising the current treatment of a fast-start resource's Start-Up Fee and No-Load Fee in the pricing process; and

(4) providing compensation to resources that, in certain circumstances, may incur a lost-opportunity cost for following the ISO's dispatch instructions when a fast-start resource sets the LMP under the new pricing method.

Each of these changes is discussed in more detail below. Additionally, provided as Attachment A to this filing is a copy of a March 4, 2015 memorandum from the ISO to the NEPOOL Markets Committee that provides additional background information and several detailed numerical examples that illustrate the mechanics and effects of the new pricing method.

With these changes, a fast-start resource may be able to set the real-time LMP under a much broader range of conditions than those under which fast-start resources are able to set the LMP today.[23] Furthermore, the energy market price is more likely to reflect the costs of operating fast-start resources whenever these resources supply energy economically – thus better signaling, through transparent market prices, the costs that must be incurred in real-time to operate the system.[24]

Moreover, as Dr. White explains, these revisions will strengthen performance incentives for *all* types of resources, not only the fast-start resources. Since there is a uniform market-clearing price in the energy and reserve markets, pricing improvements that better enable fast-start resources to set prices reflective of their costs mean that *all* resources will perceive stronger financial incentives to perform when fast-start resources operate (which tends to be during

[22] *See* White Testimony at 3-4.

[23] *See* White Testimony at 20.

[24] *See* White Testimony at 14.

stressed system conditions, when the performance of all resources is paramount).[25] Finally, Dr. White explains that these changes will also improve price signals to buyers, improving overall market efficiency.[26]

The ISO's Internal Market Monitor has reviewed these Tariff changes and has determined that they require no changes to the mitigation provisions of the Tariff, and that they raise no new market power concerns.

As explained in Part VI below, these Tariff changes were reviewed through the stakeholder processes and unanimously supported by the NEPOOL Participants Committee. In addition, the New England States Committee on Electricity, representing the six New England states in regional electricity matters, has also indicated its support for these Tariff changes.[27]

A. Honoring the Offered Minimum Output Level of a Fast-Start Resource in the Real-Time Dispatch Process

Under the current method, in the *dispatch* process, a fast-start resource's minimum output level is treated differently during the initial commitment interval and after the initial commitment interval.[28] Currently, during the initial commitment interval of a fast-start resource, the dispatch process treats the resource's minimum output level as zero MW, regardless of the level actually specified for the resource in the energy supply offer (this is often referred to as "relaxing" the resource's minimum output parameter).[29] After the initial commitment interval, the dispatch process honors (that is, satisfies) the minimum output level stipulated in the resource's supply offer during its minimum run time.[30]

As Dr. White explains, in relaxing the resource's minimum output level to zero during its initial commitment interval, the dispatch optimization treats the fast-start resource as if it is fully dispatchable between zero megawatts and the resource's *maximum* output level, regardless of the minimum output value submitted in its energy supply offer parameter. Because of this, it is possible that the dispatch system will produce a solution that specifies an output level from the fast-start resource that is greater than zero and *less* than the resource's *minimum* output level.[31]

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[25] *See* White Testimony at 15.

[26] *See* White Testimony at 16-17.

[27] The State of Connecticut does not support these Tariff changes at this time, but is not contesting this filing. Connecticut supports efficient price formation, but questions the timing of this change in light of other market changes coming into effect (such as the two-settlement capacity market).

[28] A fast-start resource's initial commitment interval is the period of time between when the fast-start resource is electronically instructed to start and the time when the resource synchronizes to the power system. This interval generally lasts five to ten minutes or less.

[29] *See* White Testimony at 5.

[30] *See* White Testimony at 8.

[31] *See* White Testimony at 26-27.

While such a value may be used to generate the dispatch solution, the electronic dispatch signal actually sent to the resource is corrected such that it satisfies the resource's offered minimum output level.[32]

This practice of sending an electronic dispatch signal to a fast-start resource that is higher than the value calculated in the economic dispatch solution can result in system-wide over-generation. To keep total generator output balanced with load system-wide, it may then be necessary to offset any such over-generation with "regulation down" signals to other generators providing Regulation service. While this problem only exists during the relatively short initial commitment interval, it nonetheless can be economically inefficient.[33]

To address this problem, under the revised method, the commitment and dispatch process will be constrained to satisfy a fast-start resource's offered minimum output level throughout its run time, including the initial commitment interval. Hence, the dispatch solution will not calculate an output level for a fast-start resource below its offered minimum output level under normal operations, and there will be no need for special logic to correct the dispatch instruction electronically sent to a fast-start resource in order to avoid sending it an infeasible dispatch level. This change will resolve the potential over-generation problem when a fast-start resource is committed and initially dispatched, and will resolve the potential inefficiencies associated with relying on other generators to provide frequency "regulation down" service to counterbalance the potential over-generation when fast-start resources are started.[34]

B. Relaxing the Minimum Output Level of a Committed Fast-Start Resource in the Pricing Process

Under the current method, in the *pricing* process, a fast-start resource's minimum output level is treated in the same manner as in the *dispatch* process. In a pricing interval associated with the initial commitment interval, a fast-start resource's minimum output level is relaxed to zero MW, regardless of the level actually specified in the supply offer. After the initial commitment interval, the pricing process enforces (does not relax) the minimum output level specified in the supply offer for the duration of the resource's minimum run time.[35]

As explained in the White Testimony, it is this feature of the current method that commonly precludes a fast-start resource from setting price after the initial commitment interval, even when the resource is economically committed and economically dispatched throughout its run time. Because fast-start resources are "lumpy," they are dispatched (after the correction is applied during the initial commitment interval) to at least their minimum output levels – which are commonly equal, or close, to their maximum output levels. When a resource is economically

[32] *See* White Testimony at 27.

[33] *See* White Testimony at 10, 27-28.

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

[35] *See* White Testimony at 29.

dispatched to its minimum output level it is typically because there is another generator, with a lower incremental cost, that would be dispatched instead to meet incremental demand. In these situations, the pricing algorithm typically determines that the fast-start resource's dispatch would not change to meet incremental demand – that is, the fast-start unit is not a marginal resource in the pricing process. As a consequence, fast-start resources generally do not set the LMP after their initial commitment interval, even when they are economically committed, economically dispatched to their minimum output level, and the highest-cost resources supplying power in the system.[36]

Under the revised rules, LMPs and RMCPs will be calculated in the real-time pricing process by relaxing a pool-committed fast-start resource's minimum output level to zero throughout its run time.[37] This will enable the pricing algorithm to treat a committed fast-start unit as the marginal resource, and therefore potentially able to set price, under a broader range of dispatch conditions than the current pricing method.[38] As Dr. White explains, these conditions generally correspond to the concept of a resource being economically useful for meeting the system's real-time energy and reserve requirements – that is, a committed fast-start resource may set the LMP when it has the highest cost among all resources operating at the time, and the power system's total production costs are lower with the fast-start resource than total production costs would be under the lowest-cost alternative without the fast-start resource.[39]

With respect to RMCPs, Dr. White explains that this filing does not change the existing co-optimization logic that jointly determines real-time energy and reserve prices. Reserve prices will continue to be set by the opportunity cost of supplying reserves, rather than energy, in real-time. However, because energy prices will change – when set by a fast-start resource – the opportunity cost of supplying reserves instead of providing energy will change accordingly. Under both the current and the new pricing methods, the opportunity cost of supplying reserves instead of energy will continue to determine all real-time RMCPs.[40]

C. Revising the Treatment of a Fast-Start Resource's Commitment Costs

A fast-start resource's commitment costs are its Start-Up Fee (designated in dollars per start) and its No-Load Fee (designated in dollars per hour). Under the current practice, these

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[36] *See* White Testimony at 29-30.

[37] *See* White Testimony at 30. To summarize, under the current method, both the dispatch and pricing processes relax the minimum output level during the initial commitment interval, but not after the initial commitment interval. Under the revised method, the *dispatch* process will not relax the minimum output level in any interval, while the *pricing* process will relax the minimum output level in all intervals.

[38] *See* White Testimony at 31. This is not to suggest that under the revised method fast-start resources will set the LMP in all of the pricing intervals in which they operate. *See* White Testimony at 35-36.

[39] *See* White Testimony at 31. In his testimony, Dr. White provides an example contrasting the current and revised real-time pricing methods. *See* White Testimony at 32-34

[40] *See* White Testimony at 34-35.

commitment costs may be incorporated into the LMP during the resource's initial commitment interval, but are not incorporated into the LMP during subsequent intervals. Specifically, the pricing process first calculates an "adjusted" incremental energy offer for each fast-start resource. This adjusted incremental energy offer combines the submitted incremental energy offer price with the resource's commitment costs.[41] The pricing process calculates LMPs and RMCPs during the initial commitment interval using the fast-start resource's adjusted incremental energy offer, instead of the incremental energy offer alone. After the initial commitment interval, pricing is based on only the resource's incremental energy offer, and the resource's commitment costs are ignored.[42]

While there are several reasons why it is beneficial to incorporate such commitment costs into the pricing process for fast-start resources,[43] Dr. White explains that there are two general concerns with the way they are incorporated in the current processes. First, amortizing the Start-Up Fee over a fixed period of one hour, despite considerable variation in the minimum run times of fast-start resources, is arbitrary and not economically justified. Fast-start resources in New England can, and do, have minimum run time offer parameters of less than one hour. Second, and more importantly, under the current method these commitment costs affect real-time prices only during a fast-start resource's initial commitment interval. As a result, the energy market's price signal fails to reflect the costs incurred to operate a fast-start resource during periods after the initial commitment interval, when the resource's operation may continue to be economically useful.[44]

To address the first problem, Dr. White explains that instead of using a fixed and arbitrary duration of one hour, the revised method will amortize a fast-start resource's Start-Up Fee over the resource's minimum run time. This means that a fast-start resource's Start-Up Fee will be amortized over a resource-specific time period ranging from a minimum of 15 minutes to a maximum of one hour (because one hour is the maximum value of the minimum run time allowed for a fast-start resource in the Tariff).[45]

To address the second problem, under the revised pricing method (and not commitment and dispatch), the No-Load Fee of a fast-start resource will be amortized over the resource's maximum output (as is performed currently) and then incorporated into (that is, added to) its incremental energy offer price throughout the resource's actual run time (a change from current

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[41] Specifically, the resource's Start-Up Fee is amortized (that is, averaged) over the product of the resource's maximum output level (in MW) and one hour; the resource's No-Load Fee is amortized over the resource's maximum output level; and the resulting values are added to the resource's incremental energy offer price. The sum total is the resource's adjusted incremental energy offer price. Dr. White provides an example of these calculations in his testimony. *See* White Testimony at 37-38.

[42] *See* White Testimony at 37-38.

[43] *See* White Testimony at 39-40.

[44] *See* White Testimony at 40-41.

[45] *See* White Testimony at 41-42.

practice). The Start-Up Fee of a fast-start resource will be amortized over the resource's maximum output and the resource's minimum run time (instead of over one hour, as is the current practice), and the amortized value will be incorporated into (that is, added to) the resource's incremental energy offer price throughout the resource's minimum run time. Thus, under the revised method, a fast-start resource's adjusted incremental energy offer price will be the sum of its incremental energy offer and its amortized no-load value and, during its minimum run time period, its amortized start-up value.[46]

Dr. White explains that incorporating the Start-Up Fee and No-Load Fee in this manner will improve price signals in the energy market by reflecting the costs incurred to operate fast-start resources that are economically useful for meeting the system's real-time energy and reserve requirements. This will help to improve price transparency, and will serve to strengthen performance incentives for all resources during operating conditions when performance tends to matter the most.[47]

D. Providing Compensation for Lost-Opportunity Costs

In his testimony, Dr. White explains that because the dispatch process (under the revised method) will enforce a fast-start resource's minimum output level in all intervals, some resources could face lost-opportunity costs. Broadly, if a fast-start resource is dispatched to its minimum output level, and this minimum output level exceeds the additional output required to meet demand, then the dispatch solution must also simultaneously re-dispatch other online resources. In this case, the system's dispatch solution may balance total supply and total demand by "posturing down" one (or possibly several) lower-cost online generators. In this context, "posturing down" means that one or more online resources may be dispatched to an output level that is less than their profit-maximizing output level when the fast-start resource sets the LMP. In this situation, an online resource dispatched below its profit-maximizing output level incurs a lost-opportunity cost by following its dispatch as instructed.[48]

This is a problem because, unless this opportunity cost is properly addressed by the market design, an affected resource may perceive a strong financial opportunity to increase its profit by increasing its real-time output above its dispatch instruction. This is not only economically inefficient – because generators may find it profitable to no longer execute their part of the least-cost dispatch for the power system – it can result in an imbalance of power supply and demand and, over time, undermine the ability and confidence of system operators to assure reliable system operation.[49]

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[46] *See* White Testimony at 43.

[47] *See* White Testimony at 44.

[48] *See* White Testimony at 45.

[49] *See* White Testimony at 47.

To address this problem, under the revised rules, certain resources "postured down" in these specific circumstances will be compensated for their lost-opportunity costs. This will eliminate the potential financial incentive for a resource to not follow its dispatch instruction that may otherwise arise when a "lumpy" fast-start resource sets the real-time LMP.[50] Specifically, these lost-opportunity cost payments will be paid to a resource that is "postured down" to balance the system when a fast-start resource sets the LMP at a value higher than the resource's energy price offer. Resources that are not dispatchable would not be postured down by the dispatch system in these situations, so it is appropriate that no lost-opportunity cost payments will be calculated or provided to resources that are not dispatchable in real-time. Accordingly, no lost-opportunity cost payments are to be provided to Settlement Only Resources, Demand Response Resources, or External Transactions. In addition, to avoid duplicative credits to resources that may receive lost-opportunity cost compensation through other, existing provisions of the Tariff, there is an exception for any resource that has been Postured (pursuant to other provisions of the Tariff), or that provides Regulation service during the same hour.[51]

Dr. White explains that these payments are consistent with other lost-opportunity cost payments in the real-time markets,[52] that such payments are superior to penalties and other Tariff requirements that may seek the same end,[53] and that they in no way constitute a "double" payment.[54] He also explains that a resource cannot increase its lost-opportunity cost payment by producing less than its dispatch instruction.[55]

E. Anticipated Economic Impacts

In his testimony, Dr. White presents the results of a detailed impact analysis of these changes to fast-start pricing in the real-time energy and reserves markets. This analysis consisted of re-running the ISO's production-level dispatch and pricing software, with modifications to perform the new fast-start pricing method, using system data from 2014.[56] This analysis indicates that, had the fast-start pricing changes described here been in effect during 2014:[57]

- the estimated change in the average annual real-time system energy price during the study period, as a result of these pricing improvements, would be $3.10 per MWh;

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[50] *See* White Testimony at 47.

[51] *See* White Testimony at 51-52.

[52] *See* White Testimony at 48.

[53] *See* White Testimony at 48-50.

[54] *See* White Testimony at 51.

[55] *See* White Testimony at 52.

[56] *See* White Testimony at 54.

[57] *See* White Testimony at 55-56.

- the real-time energy charges to load deviations would have increased by approximately $20.5 million;

- the real-time reserve payments would have increased by approximately $11.6 million;

- the total lost-opportunity cost payments would have been approximately $3.2 million; and

- the estimated reduction in total real-time NCPC in 2014 that would have resulted from the improved method presented here (after accounting for the impact of other NCPC-related rules implemented since that time) is approximately $17.2 million (comprised of an estimated reduction in the real-time NCPC paid to fast-start resources of $7.1 million, and an estimated reduction in the real-time NCPC paid to non-fast-start resources of $10.1 million (attributable to the higher real-time LMPs and RMCPs when fast-start resources set price)).

As Dr. White notes, given the estimated total lost-opportunity cost payments of $3.2 million and a reduction in total real-time NCPC of $17.2 million, the instant changes would have resulted in an estimated net reduction in total real-time out-of-market payments of $14 million ($17.2 million minus $3.2 million) during the 2014 study period.[58]

F. Implementation in the Real-Time Energy and Reserves Markets Only

The revised fast-start dispatch and pricing method will be implemented in the real-time energy and reserves markets only. As explained in the White Testimony, this is because implementation in the day-ahead market will have a far smaller beneficial impact than implementation in the real-time markets.[59] Moreover, focusing implementation on the real-time markets will reduce the complexity and allow for faster implementation of this project in the market where it will provide the most benefit. As Dr. White explains, changes to the pricing logic in the day-ahead market for fast-start resources will likely be undertaken in the future, in conjunction with other enhancements to the day-ahead market.[60]

V. DETAILED DESCRIPTION OF SPECIFIC TARIFF REVISIONS

As discussed above and in the White Testimony, the changes made by this filing fall into four general categories: (1) adjusting the real-time dispatch process to satisfy the offered minimum output level (“Economic Minimum Limit”) of each committed fast-start resource

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[58] *See* White Testimony at 56.

[59] *See* White Testimony at 17.

[60] *See* White Testimony at 17-18.

during its initial commitment interval;[61] (2) "relaxing" a pool-committed fast-start resource's Economic Minimum Limit to zero in the pricing process that calculates real-time LMPs and RMCPs; (3) revising the current treatment of a fast-start resource's Start-Up Fee and No-Load Fee in the pricing process; and (4) providing compensation to resources that, in certain circumstances, may incur a lost-opportunity cost by following the ISO's dispatch instructions when a fast-start resource sets the LMP under the new pricing method. The specific Tariff revisions relating to each of these are discussed in turn below.

As an initial matter, however, the changes made by this filing include some changes to defined terms in Section I.2.2 of the Tariff. "Rapid Response Pricing Asset" is a new term being added to the definitions section of the Tariff (Section I.2.2) and will be defined as "a Fast Start Generator, a Flexible DNE Dispatchable Generator, or a Dispatchable Asset Related Demand for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Run Time does not exceed one hour; and (ii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes." A Rapid Response Pricing Asset is not a new type of resource. It is simply a new term that obviates the need to refer to three separate resource types throughout the new pricing rules. For Dispatchable Asset Related Demand, the Rapid Response Pricing Asset definition includes restrictions regarding Minimum Run Time and cold notification and start-up time that already apply to Fast Start Generators and Flexible DNE Dispatchable Generators (per their existing definitions in Section I.2.2), ensuring that the new provisions apply only to Dispatchable Asset Related Demand that is actually fast-start.

As explained in the White Testimony, the definition of Rapid Response Pricing Asset does not apply to Fast Start Demand Response Resources at this time. However, these rule changes will permit the new pricing treatment to be applied to Fast Start Demand Resources after the full integration of demand response resources into New England's real-time energy and reserve markets is implemented.[62]

In creating the Rapid Response Pricing Asset term, the ISO reviewed the definitions of the underlying fast-start resource types, and identified two minor changes to those. First, in the definition of Fast Start Generator, the terms Minimum Run Time and Minimum Down Time are being capitalized to reflect that they are proper defined terms. Second, in the definitions of Fast Start Demand Response Resource, Fast Start Generator, and Flexible DNE Dispatch Generator, the criteria stating that the resource has satisfied its Minimum Down Time (or Minimum Time Between Reductions, in the case of Fast Start Demand Response Resources), is being removed. This is because the criteria listed in each of those definitions should be confined to the resource's static physical characteristics, and should not include its minute-to-minute operating state. A resource that has not satisfied its Minimum Down Time does not cease being a fast-start resource. Information about whether a resource has satisfied its applicable minimum time criteria is instead reflected in the specific provisions of new Section III.2.4, discussed below.

[61] A resource's Economic Minimum Limit is defined in the Tariff (at Section I.2.2) as a resource-specific parameter based on the physical and operational characteristics of the resource.

[62] *See* White Testimony at 24-25.

A. Honoring the Economic Minimum Limit of a Fast-Start Resource in the Dispatch Process

As previously explained, under the current dispatch process, a fast-start resource's Economic Minimum Limit is relaxed to zero during the initial commitment interval; the Economic Minimum Limit is not relaxed subsequently during the resource's minimum run time. Under the new fast-start method presented here, the real-time dispatch process will not relax a fast-start resource's Economic Minimum Limit at all. No Tariff revisions are needed to implement this change, because the ISO already has the necessary authority regarding dispatch under Section III.1.11.1 of the currently effective Tariff. Specifically, that section states that "[t]he ISO shall have the authority to direct any Market Participant to adjust the output or demand reduction of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid."[63]

B. Relaxing the Economic Minimum Limit of a Committed Fast-Start Resource in the Pricing Process

As explained above, under the revised fast-start method, the calculation of LMPs and RMCPs in the real-time pricing process will relax a pool-committed fast-start resource's Economic Minimum Limit to zero in all pricing intervals during its run time. This is accomplished in new Tariff Sections III.2.4 and III.2.4(a).

New Section III.2.4, titled "Adjustment for Rapid Response Pricing Assets," states that the energy offer of a Rapid Response Pricing Asset will be adjusted for any real-time pricing interval during which it is committed by the ISO and not Self-Scheduled. Intervals in which the Rapid Response Pricing Asset are Self-Scheduled are excluded because the act of Self-Scheduling a resource indicates that the resource wishes to be a price-taker in the energy market for quantities up to the resource's offered minimum output level.[64] New Section III.2.4 also indicates that the adjustment shall apply to the price calculations described in existing Section III.2.5 (calculation of nodal real-time prices) and existing Section III.2.7A (calculation of real-time reserve clearing prices).

The specific adjustment that relaxes the fast-start resource's Economic Minimum Limit in these circumstances is contained in subsection (a) to new Section III.2.4. That subsection (which applies to the pricing process only, not the dispatch process) states that if the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero, and if the Rapid Response Pricing Asset is a

[63] As explained in the White Testimony, under the current process, during a fast-start resource's initial commitment interval the electronic dispatch signal actually sent to the resource is corrected to satisfy the resource's offered Economic Minimum Limit, consistent with the requirements of Section III.1.11.1. *See* White Testimony at 26-27.

[64] *See* White Testimony at 23.

Dispatchable Asset Related Demand, its Minimum Consumption Limit shall be set to zero. Again, this treatment will apply in all pricing intervals in which the fast-start resource is committed and not Self-Scheduled.

C. Revising the Treatment of a Fast-Start Resource's Commitment Costs

As previously explained, under the revised fast-start method, a fast-start resource's Start-Up and No-Load fees will be incorporated into the pricing process beyond its initial commitment interval. This revised treatment is described in new Section III.2.4 and its subsections (b) through (e).

Subsections (b) and (c) of new Section III.2.4 address Fast Start Generators and Flexible DNE Dispatchable Generators. Pursuant to subsection (b), where such a resource has *not* satisfied its Minimum Run Time in the interval in question, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit. Pursuant to subsection (c), where such a resource *has* satisfied its Minimum Run Time in the interval in question, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit. In this way, the rules effectuate the design described above whereby a fast-start resource's start-up and no-load costs are incorporated into pricing during the resource's Minimum Run Time; thereafter, only the resource's no-load costs are incorporated into pricing.

Subsections (d) and (e) of new Section III.2.4 create essentially the same structure for Dispatchable Asset Related Demand, but using the requisite terminology applicable to that resource type. Specifically, pursuant to subsection (d), if the Dispatchable Asset Related Demand has *not* satisfied its minimum consumption time,[65] its energy offer shall be decreased by: (i) the Start-Up Fee divided by the product of the Maximum Consumption Limit and the minimum consumption time; and (ii) the No-Load Fee divided by the Maximum Consumption Limit. Pursuant to subsection (e), if the Dispatchable Asset Related Demand *has* satisfied its minimum consumption time, its energy offer shall be decreased by the No-Load Fee divided by the Maximum Consumption Limit. In these subsections, the energy offer of Dispatchable Asset Related Demand is decreased (as opposed to increased, as in the case of Fast Start Generators and Flexible DNE Dispatchable Generators) because Dispatchable Asset Related Demand participates in the energy markets via Demand Bids rather than Supply Offers.

New Section III.2.4 also provides default values to be used if resource-specific values are not included in the submitted Offer Data. Specifically, if no Start-Up Fee or No-Load Fee is specified in the submitted Offer Data, a value of zero shall be used, and if no Minimum Run

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[65] The minimum consumption time parameter for Dispatchable Asset Related Demand is not reflected in the current Tariff and is not added in the instant Tariff revisions. That parameter will be discussed with stakeholders through the Participant Processes and filed with the Commission as part of a separate set of Tariff changes with an anticipated effective date that is earlier than the March 31, 2017 effective date for the changes in this filing.

Time or minimum consumption time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or minimum consumption time is less than 15 minutes, a duration of 15 minutes shall be used. This 15-minute value corresponds to the shortest frequency with which the ISO's forward-looking fast-start commitment software will evaluate start-up and shut-down decisions for fast-start resources under normal operating conditions. Thus, a resource-submitted Minimum Run Time of less than 15 minutes is, *de facto*, a minimum run time of 15 minutes. The default values in new Section III.2.4, for purposes of fast-start pricing, align the Tariff treatment with the practice.

Rounding out these changes are three very minor edits in Section III.2.5. First, in Section III.2.5(a), a parenthetical is added noting that the energy offers and bids used in calculating nodal real-time prices will be as adjusted pursuant to the new Section III.2.4 described above. Second, later in Section III.2.5(a), an internal cross reference is corrected. Third, in Section III.2.5(b), an extraneous word is deleted.

D. Compensation for Lost-Opportunity Costs for Resources that are Postured Down When Fast-Start Resources Set the LMP

The lost-opportunity cost compensation described above and in the White Testimony is codified in new Section III.F.2.3.10. This compensation is a new type of NCPC Credit, and so belongs in Appendix F, which addresses Net Commitment Period Compensation accounting, and which describes, in Section III.F.2, the various NCPC Credits. In Appendix F as revised, the new lost-opportunity cost NCPC Credit that results in certain circumstances when a Rapid Response Pricing Asset sets the LMP is termed the "Rapid Response Pricing Opportunity Cost." This new term is also being added to the definitions section of the Tariff (Section I.2.2).

New Section III.F.2.3.10.1 describes which resources are eligible to receive the Rapid Response Pricing Opportunity Cost NCPC Credit. Specifically, during any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, all resources that are committed and able to respond to Dispatch Instructions during the interval are eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit. As discussed below, however, eligibility does not guarantee compensation.

As explained in the White Testimony,[66] there are three exceptions to this broad eligibility that are provided in New Section III.F.2.3.10.1. The credit shall be zero if: (i) the Resource is non-dispatchable; (ii) the Resource has been Postured or has provided Regulation service at any time during the hour in which the interval occurs; or (iii) if the Resource is a Settlement Only Resource, a Demand Response Resource, or an External Transaction. Generally, these exceptions apply where the resource would not be postured down by the dispatch and thus no lost-opportunity cost would arise (cases (i) and (iii)) or where the resource may otherwise receive duplicative lost-opportunity cost credits under other, existing provisions of the Tariff (case (ii)).

[66] *See* White Testimony at 51-52.

As stated in new Section III.F.2.3.10.4, each resource's Rapid Response Pricing Opportunity Cost NCPC Credit in an interval is calculated as the difference between the amount the resource would have earned for energy and reserves absent being postured down (its "economic net revenue") and the amount that it actually earned for energy and reserves in the interval (its "actual net revenue"). So that the calculation does not result in a charge, if the actual net revenue exceeds the economic net revenue, then the Rapid Response Pricing Opportunity Cost NCPC Credit in the interval shall be zero.

The calculation of a resource's economic net revenue for an interval in which a Rapid Response Pricing Asset is committed by the ISO (and not Self-Scheduled) is more fully described in new Section III.F.2.3.10.2. That new section states that the economic net revenue for the resource during the pricing interval is the resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities. The optimized feasible energy and reserve quantities are determined consistent with the resource's offer parameters, and are the energy and reserve quantities that maximize the resource's net real-time energy and reserve revenue for the pricing interval, taking prices as fixed during the interval and without changing the resource's commitment status. This calculation corresponds to the resource's net revenue if it were to operate at its profit-maximizing output level during the interval, taking prices as fixed, and is the first part of the lost-opportunity cost calculation.

The second part of the lost-opportunity cost calculation is a resource's actual net revenue for an interval in which a Rapid Response Pricing Asset is committed by the ISO (and not Self-Scheduled). This is described in new Section III.F.2.3.10.3. That new section states that the actual net revenue for a resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy multiplied by the Real-Time Price, plus the dispatched reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities. As explained in the White Testimony, using the greater of the two values in the determination of actual net revenue serves to ensure that a resource receiving a lost-opportunity cost payment cannot increase this payment by producing less than its dispatch instruction.[67]

The remaining changes to Appendix F all simply reflect the inclusion of the new type of NCPC Credit. In Section III.F.2.2.2.4, a sentence is added noting that a resource's hourly revenue must be increased by any Rapid Response Pricing Opportunity Cost NCPC Credits. In Section III.F.2.4, which addresses the apportionment of NCPC Credits, Rapid Response Pricing Opportunity Cost NCPC Credits are added to the list of NCPC Credits that are assigned to the hours for which the credit was calculated. In Section III.F.2.5, Rapid Response Pricing Opportunity Cost NCPC Credits are added to the list of NCPC Credit types that are given a specific designation for purposes of allocating NCPC costs. And in Section III.F.3.1.2, which

[67] *See* White Testimony at 52.

addresses how NCPC costs for the Real-Time Energy Market are allocated and charged, a new subsection (e) is being added stating that the costs of Rapid Response Pricing Opportunity Cost NCPC Credits will be allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand (pumps only). This treatment of costs is similar to the treatment of other costs addressed in Section III.F.3.1.2. Finally, a very minor typographical error in Section III.F.3.1.2(a) is being corrected.

VI. STAKEHOLDER PROCESS

The Tariff revisions filed here were considered through the complete NEPOOL Participant Processes and received the unanimous support of the NEPOOL Participants Committee. At its June 2-3, 2015 meeting, the NEPOOL Markets Committee, based on a show of hands (with one opposition within the Transmission Sector recorded and a number of abstentions noted), voted to recommend that the NEPOOL Participants Committee support the changes. The NEPOOL Participants Committee, at its June 23-25, 2015 meeting, unanimously approved these revisions as part of its Consent Agenda.[68]

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 market rule changes do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[69] Notwithstanding its request for waiver, the Filing Parties submit 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 Matthew White, sponsored solely by the ISO;

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[68] The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's approval of the Consent Agenda included its support for the revisions filed here, with abstentions noted by Eversource Energy, Littleton (NH) Water & Light Department, The United Illuminating Company, Vermont Electric Cooperative, and Vermont Public Power Supply Authority.

[69] 18 C.F.R. § 35.13 (2015).

- Blacklined Tariff sections effective March 31, 2017;

- Clean Tariff sections effective March 31, 2017;

- Attachment A: March 4, 2015 Memorandum to the NEPOOL Markets Committee, "Fast-Start Pricing Improvements – Revised Edition;" and

- 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) – As set forth in Part I above, the ISO requests that the Tariff revisions filed here become effective on March 31, 2017.

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/participate/participant-asset-listings. 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 Parts IV and V of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Part IV of this transmittal letter.

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

35.13(b)(7) – Neither the ISO nor NEPOOL has 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 do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

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

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

VIII. CONCLUSION

For the reasons set forth above, the ISO requests that the Commission issue an order, by December 15, 2015, accepting these changes to the fast-start pricing method with an effective date of March 31, 2017.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
ISO New England Inc. and	)	Docket No. ER15-_____-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 the ISO's market design enhancements and associated rule changes to improve real-time price formation when fast-start resources are deployed, including the rationale for these enhancements and their expected impact on market outcomes.

Q: What role did you play in the development of these market design enhancements?

A: I supervised the development of these market design enhancements by a team of qualified professionals, employed by the ISO, consisting of engineers, economists, optimization specialists, data analysts, and information-technology experts.

Q: How is your testimony organized?

- In Part III, I describe the problems that exist under the current fast-start pricing method.

- In Part IV, I explain how the ISO developed the instant improvements to the fast-start pricing method.
- In Part V, I provide a detailed description of the design changes being filed here.
- In Part VI, I discuss the anticipated economic impacts of the revised pricing method.

III. PROBLEMS WITH THE CURRENT FAST-START PRICING METHOD

Q: What are fast-start resources and why are they important?

A: As the name implies, fast-start resources are those that can start quickly. Generally, the term "fast start" describes resources that can be started in thirty minutes or less, that have a minimum run time of one hour or less, and that have a minimum down time of one hour or less.[1] Resources meeting these criteria play an important role in operating the system efficiently and reliably. Fast-start resources provide essential operating reserves when offline, allow the ISO to respond quickly and reliably to unanticipated system conditions, and can help to satisfy peak loads on the power system.

Q: Please summarize briefly why price formation is a concern when fast-start resources are deployed.

A: Once started, fast-start resources are generally inflexible. By inflexible, I mean that fast-start resources typically operate inefficiently at less than their maximum output, or may not be able to physically operate much below their maximum output. As a consequence,

[1] Additional criteria applicable to fast-start resources are specified in the Tariff in Section I.2.2, in the definitions of Fast Start Demand Response Resources, Fast Start Generators, and Flexible DNE Dispatchable Generators. (The term "Flexible DNE Dispatchable Generator" will become effective in the Tariff in April 2016 pursuant to *ISO New England Inc. and New England Power Pool Participants Committee*, 152 FERC ¶ 61,065 (July 23, 2015).)

the energy supply offer parameters of these resources may stipulate that they be dispatched either to zero output, or to a minimum level that is at (or close to) their maximum output, and not in between. Because of this limited dispatchable range (once started), these resources are commonly referred to as having "lumpy" output (or as being "lumpy resources," for short).

Importantly, the ISO's current real-time pricing and dispatch algorithms treat fast-start resources as able to meet the "next MW of demand" when they are initially committed and starting up – a process that generally takes no more than five to ten minutes. However, because they must be dispatched to a minimum output that is at, or close to, their maximum output, these resources frequently add more power to the system than the incremental demand for power (which, in turn, requires other, online resources to be concurrently dispatched down slightly). In these situations, the ISO's real-time pricing algorithm commonly determines that, once operating, the fast-start resource's dispatch would not change if there is a perturbation in demand – a requisite condition for a generator's supply offer to set the Locational Marginal Price ("LMP").

As a direct consequence, fast-start resources generally do not set the LMP, even when they are economically committed, economically dispatched, and the highest-cost resources supplying power in the system (that is, the fast-start resource has the highest-cost offer at the time). From a price formation standpoint, in these conditions the energy market's price signal fails to convey the costs of operating the fast-start resource – costs that the ISO must incur to operate the power system reliably and economically.

Q: Please describe further how prices in the Real-Time Energy Market are determined when fast-start resources are committed and dispatched.

A: A number of elements determine how real-time LMPs are calculated when fast-start resources are committed and dispatched. Here I will focus on a central element of this process that, in large part, determines when – if at all – an economically-committed and economically-dispatched fast-start resource may set the LMP. (Other elements of this pricing process are addressed later, in Part V.C of this testimony.) The central element is the treatment of the minimum output level of a fast-start resource in the ISO's current real-time dispatch and pricing systems. The treatment is different at the initial commitment of a fast-start resource than during the remainder of the resource's minimum run time.

Q: How are fast-start resources currently treated at the time they are initially committed?

A: A fast-start resource's initial commitment interval is the period of time between when the fast-start resource is electronically instructed to start and the time when the resource synchronizes to the power system. This interval generally lasts five to ten minutes or less. Currently, during the initial commitment interval of a fast-start resource, both the dispatch process and the associated pricing process treat the resource's minimum output level as zero MW. This treatment is applied even though the minimum output level specified in the resource's energy supply offer parameter is greater than zero. This specific treatment is referred to as "relaxing" the minimum output parameter.

As noted, this "relaxation" treatment of the minimum output parameter is applied differently during the initial commitment interval and after the initial commitment interval. Moreover, it has substantively different implications for the dispatch process and for the pricing process.

Q: What are the implications of the current "relaxation" treatment for the dispatch process, during the initial commitment interval?

In the ISO's dispatch process, the implication of relaxing the minimum output level to zero during the resource's initial commitment interval is that the resource is assumed to be fully dispatchable, between zero and the resource's maximum output, at the time it is instructed to start. As a result, at the time a fast-start resource is committed, the ISO's dispatch solution may calculate a dispatch level that is infeasible for the resource (because the calculated dispatch point, in MW, may be below the resource's actual minimum output level). The ISO's software currently has additional logic for the purpose of identifying these situations in real-time, and corrects the electronic dispatch instruction sent to the fast-start resource at its initial commitment to satisfy the resource's minimum output level (as stated in its energy supply offer parameters).

This need to correct the start-up dispatch instructions sent to fast-start resources is not ideal. In particular, because the correction increases the dispatch instruction sent to the fast-start resource above the level calculated by the optimized dispatch solution, it can result in system dispatch instructions that call for more total generation than total energy demand. That, in turn, may prompt "regulation down" signals to be sent to other resources providing Regulation service at the time, in order to offset the effect of the imbalanced power dispatch. Altogether, this outcome can have a greater cost than would occur with a more efficient fast-start dispatch and pricing process that avoids an imbalanced power dispatch in the first place. I discuss this problem, and its consequences, in further detail in Part V.A.

Q: What are the implications of the current "relaxation" treatment for the pricing process, during the initial commitment interval?

In the ISO's pricing process, the implication of relaxing the resource's minimum output level to zero is that the resource is no longer treated as "lumpy" during the initial commitment interval (commonly associated with one or two five-minute real-time pricing intervals). That is, like the current dispatch process, the current pricing process treats the fast-start resource as being able to produce any output level between zero MW and its offered maximum output level when it is instructed to start. This "relaxation" treatment greatly increases the likelihood that, when a fast-start resource is initially committed, the pricing algorithm will treat it as the marginal resource that will satisfy the next MW of demand – and therefore will set the LMP.

This "relaxation" treatment is why fast-start resources are commonly able to set the LMP during their initial commitment interval, under the current real-time pricing algorithm. However, this treatment is not applied similarly after the initial commitment interval.

Q: After the initial commitment interval, how are fast-start resources treated?

A: After the initial commitment interval, for the remainder of the resource's minimum run time, the resource's minimum output level is not "relaxed." That is, once the fast-start resource has synchronized to the power system and is generating power, both the dispatch solution and the associated pricing solution honor (that is, satisfy) the minimum output level stipulated in the resource's energy supply offer parameters during its minimum run time.

Again, this treatment of the minimum output parameter after the initial commitment interval has different implications for the dispatch process and for the pricing process. In the ISO's dispatch process, the implication of honoring the minimum output level is that the ISO's dispatch solutions will calculate dispatch levels that are feasible for the resource (*i.e.*, the calculated dispatch point, in MW, will not be less than the resource's minimum output level). Thus, no additional logic is necessary to correct the dispatch instruction sent to the fast-start resource, as occurs when the resource is initially committed. Moreover, the system does not experience the problem of dispatching more total generation than total energy demand, as I discussed previously with respect to the initial commitment period.

Q: After the initial commitment interval, what are the implications of *not* applying the "relaxation" treatment for the current pricing process?

A: In the ISO's pricing process, the implication of honoring the resource's offered minimum output level is that the resource becomes "lumpy" in the pricing algorithm. As noted previously, when a resource is dispatched at its minimum output level, the pricing algorithm commonly determines that the resource's dispatch would not change to meet the next MW of demand on the system. Indeed, in these situations, the fast-start resource is commonly dispatched at its minimum output level precisely *because* there is another generator, with a lower incremental cost, that would be dispatched instead to meet the next MW of demand. As a consequence, fast-start resources generally do not set the LMP after their initial commitment interval, even when they are economically committed, economically dispatched (at their minimum output level), and the highest-cost resources supplying power in the system.

Q: Please summarize the ISO's concerns with the current pricing and dispatch method when fast-start resources are deployed.

A: In summary, there are two significant problems with the current method. First, fast-start resources typically do not set the real-time energy market price under the ISO's current method, even though they are routinely committed and dispatched, in least-cost manner, to meet demand and ensure reliable operation of the power system. While these resources generally do set price during their initial commitment interval (when their minimum is "relaxed"), they generally do not set price *after* their initial commitment interval (when their minimum is not "relaxed") – and, importantly, the period *after* the initial commitment interval comprises the bulk of the run time for fast-start resources, in practice.

As a result, for the bulk of the time that a fast-start resource operates, the market's real-time price signals often fail to reflect the costs to operate the fast-start resource – costs that must be incurred to operate the system economically and reliably. In simple terms, fast-start resources are chronically undervalued in the real-time market, in the sense that the real-time LMP commonly does not cover their operating costs (as offered); instead, to cover their costs, many fast-start resources must rely on Net Commitment Period Compensation ("NCPC," informally called "uplift" or "make whole" payments).[2]

The second problem is that, when a fast-start resource is initially committed, the current fast-start logic may yield a dispatch solution with a small amount of over-generation system-wide. Although the period in which this occurs is not long (as it is associated with only the initial commitment interval), it can require "regulation down" service by other generators on Automatic Generation Control to offset the effect of the imbalanced power system dispatch. From an economic perspective, this unnecessary use of Automatic Generation Control service may have a greater cost than would occur with a more efficient fast-start dispatch and pricing method that avoids this over-generation instruction problem.

Q: Has the ISO's External Market Monitor reviewed whether the current pricing method for fast-start resources is appropriate?

The ISO's External Market Monitor, Potomac Economics, expressed similar concerns with fast-start pricing in its 2013 Assessment of the ISO New England Electricity

[2] Capitalized terms not otherwise defined in my testimony are intended to have the meanings described in the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

Markets.[3] It stated that:

> "[f]ast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2013, 60 percent of the fast-start capacity that was started in the real-time market did not recoup its offer. This leads fast-start resources with flexible characteristics to be substantially under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits."[4]

Potomac Economics recommended that "the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices."[5]

Q: If the current method is not appropriate, why was it adopted?

A: The current method was developed well over a decade ago. To reduce the real-time computational burden associated with commitment, dispatch, and pricing of fast-start resources at the time, it was important to simplify the design of those processes. The approach in current use was reasonable in light of the practical constraints that existed at the time, but entails important shortcomings as observed above.

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[3] *See* Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, June 2014, available at http://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/ind_mkt_advsr/isone_2013_emm_report_final_6_25_2014.pdf ("2013 Market Assessment").
[4] 2013 Market Assessment at p. 22.
[5] *Id*.

Technological change in recent years has made many other methods feasible. In particular, technology now permits the ISO to perform separate (but closely-related) optimization processes for the commitment, dispatch, and pricing of fast-start resources. These technological enhancements, in conjunction with the changes described in this filing, will enable the ISO to improve price formation when fast-start resources are economically committed and dispatched.

IV. DEVELOPING IMPROVEMENTS TO FAST-START PRICING

Q: How did the ISO go about developing an improved fast-start pricing method?

A: The ISO first conducted a survey study, which I supervised and co-authored, of the fast-start commitment, dispatch, and pricing methods used by various ISOs and RTOs. The results of this study – presented to stakeholders in New England in November and December 2014 as part of a series of technical sessions on real-time price formation – are available on the ISO's website.[6] This study yielded a wealth of information about various approaches to fast-start pricing. We examined the pros and cons of various methods, from both theoretical and practical perspectives.

Q: What did you conclude from this study of fast-start pricing methods?

A: The ISO drew three principal conclusions from this study. First, fast-start pricing methods vary widely across the various ISOs and RTOs. The differences are manifest in

[6] *See* ISO New England, Inc., *Real-Time Price Formation: Fast-Start Pricing – A Survey*, November 14, 2014 (Technical Session #7, available at http://www.iso-ne.com/static-assets/documents/2014/11/price_information_technical_session7.pdf) ("Fast-Start Pricing Part I") and December 15, 2014 (Technical Session #8, available at http://www.iso-ne.com/static-assets/documents/2014/12/price_information_technical_session8.pdf) ("Fast-Start Pricing Part II").

many different dimensions, including what resources qualify as “fast-start” technologies, how their operating constraints are handled in real-time dispatch, how such constraints are handled in real-time pricing algorithms, and so on. In my opinion, it appears that different regions have weighed the trade-offs inherent in the problem differently, selecting different methods on the basis of various economic and operational considerations.[7]

Second, there is no “perfect” solution to the problem of fast-start pricing – whether from the standpoint of economic theory, or as an unambiguous, state-of-the-art “best practice.” Reforms to fast-start pricing can reduce total out-of-market payments and better reflect the costs of fast-start resource deployments in energy and reserve market prices, but they cannot, in principle or in practice, completely eliminate out-of-market payments to fast-start resources. More specifically, although fast-start pricing improvements can shift a greater share of resources’ total compensation into the LMP-based energy and reserves markets, the potential for out-of-market payments cannot be eliminated completely given the “lumpy” nature of fast-start generators. These out-of-market payments remain necessary, in some conditions, to ensure units are properly compensated and have proper incentives to follow dispatch instructions.

The third important conclusion is that, while there is no “perfect” solution to the problem of fast-start pricing, the ISO’s current fast-start pricing method could be improved significantly. In particular, with technical changes to the current pricing method when

[7] For a summary of the key design elements culled from ISO-NE’s survey of ISO/RTO fast-start pricing methods, and the trade-offs among them, *see* Fast Start Pricing Part II, slides 67-74.

fast-start units are economically committed and dispatched, it is possible to address the two central problems with the ISO's current fast-start pricing and dispatch methods that I summarized in Part III above (*viz.*, the infrequency with which fast-start resources set price, and the potential for system-wide over-generation instructions at start-up). I will discuss the specific technical changes that enable these improved outcomes in detail in Part V of this testimony, below.

Q: At a high-level, will the revised method better reflect the costs of deploying fast-start resources in market prices? Do you expect the revised method will reduce out-of-market payments overall?

A: Yes, to both questions. While there is no perfect solution to pricing with "lumpy" resources like fast-start units, the rule changes filed here represent a significant improvement. As I show in Part V below, under the revised rules the energy market price is more likely to reflect the costs of operating fast-start resources whenever these resources supply energy economically – thus better signaling, through transparent market prices, the costs that must be incurred in real-time to operate the system.

We have conducted a market simulation analysis of the specific changes presented here that leads me to expect these changes will reduce total real-time NCPC payments to both fast-start resources and non-fast-start resources in the New England system. Based on that analysis, the estimated net reduction in total real-time out-of-market payments in 2014 that would have resulted from the improvements presented here (after accounting for other rules implemented since that time) is approximately $14 million. As a reference point, the actual value of total real-time NCPC during 2014 was $93.3 million. In Part VI below, I describe further the simulation analysis we performed to quantify this effect, and the interpretation of the principal results.

Q: Will the revised rules improve resources' performance incentives?

A: These rule changes will strengthen performance incentives for *all* types of resources – not only the fast-start resources. As previously discussed, under the current rules, the energy market's real-time price signals commonly do not reflect the costs incurred to operate fast-start resources. Since there is a uniform market-clearing price in the energy and reserve markets, pricing improvements that better enable fast-start resources to set prices reflective of their costs mean that *all* resources will perceive stronger financial incentives to perform when fast-start resources operate.

This is an especially important point because fast-start resources tend to operate during stressed system conditions, when the performance of all resources – not simply the fast-start resources – is paramount. The ISO's real-time economic dispatch system will often start high-cost, fast-start resources during the operating day when the system is facing unanticipated operating situations, experiencing rapid increases in net load, or recovering from a sudden disturbance like a major generator or transmission loss. Thus, fast-start resources tend to run during periods of scarce supply and heightened reliability risk. The inability of these resources to set an energy market price that reflects their high operating costs means the market *as a whole* sees inappropriately low price signals at precisely the times when energy and reserves are most valuable, and when suppliers' performance incentives should be greatest.

Under the revised rules, the market's price signals will better reflect the higher costs associated with fast-start deployments during these stressed system conditions, providing all resources with stronger performance incentives in these conditions. Thus, like well-designed performance incentives generally, improving real-time price formation when fast-start resources are deployed will send market price signals that are targeted to the specific times when performance is particularly important to system reliability.

Q: Are there other potential benefits, arising on the buyer side of the marketplace?

Yes. Under the revised rules, the buyer side (or "load" side) of the marketplace will also see these appropriately-timed, higher price signals in the real-time energy market. That provides stronger incentives for wholesale buyers to more accurately forecast their end-users' consumption the next day, so as to be able to buy the energy they will use at the day-ahead price and avoid potential charges at higher real-time prices for energy procured in the real-time market – when higher-cost fast-start resources may now set the price. This buy-side market response to potentially higher real-time price signals during stressed system conditions can improve overall market efficiency, since there are generally lower-cost options to meet demand when manifest day-ahead than in real-time alone.

The ISO's External Market Monitor expands on this point in its 2013 Market Assessment, noting that with "more efficient real-time pricing during fast-start resource deployments … [i]ncentives to purchase more in the day-ahead market would increase, which would increase the amount of lower-cost generation committed in the day-ahead market."[8] The External Market Monitor concluded that "these responses would substantially improve efficiency because higher-cost peaking generation would be displaced by lower-cost intermediate generation."[9]

Q: Will the revised method apply to both the day-ahead and real-time markets?

A: No. At present, the revised method is being implemented in the real-time energy and reserves markets only. Changes to the pricing logic in the day-ahead market for fast-start resources will likely be undertaken in the future, in conjunction with other enhancements to the day-ahead market.

Q: Please explain why the ISO plans to implement the revised method in the real-time markets only at this time.

A: In brief, the reasons are practical. I do not expect that implementation in the day-ahead market will have nearly as significant a beneficial impact as in the real-time market, due to the characteristics of New England's fast-start resources. Moreover, implementing fast-start pricing reforms in only the ISO's real-time software systems at this time will reduce the complexity – thus expediting the ISO's implementation – of this project in the market where it will provide the most benefit.

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[8] 2013 Market Assessment at p. 95.
[9] *Id*.

To elaborate on these points, note that most fast-start resources do not clear in the day-ahead market. This is especially true for the system's fossil-fuel fast-start resources, which are a combination of internal-combustion units and simple-cycle peaking units. Resources of these types operate on expensive fuels (primarily distillates), and have sufficiently high operating costs that they are generally uncompetitive – and thus infrequently clear – in the day-ahead market. For example, in 94.5 percent of the hours of 2014, *none* of the system's fossil-fuel fast-start resources cleared in the day-ahead market. As noted previously in my testimony, these high-cost resources primarily operate in response to unanticipated real-time system conditions – thus the key benefits of fast-start pricing reforms should result from implementation in the real-time markets, rather than the day-ahead market.

It is useful to note there are other fast-start technologies in the New England system, and at present there are a handful of large, hydroelectric fast-start resources that clear in the day-ahead market more frequently. These large hydroelectric resources have significant dispatchable ranges (*e.g.*, maximum output levels that are up to twice as large as their minimum output levels). Because of their large dispatchable ranges, these resources can clear in the day-ahead market at a MW level between these two limits – in which case they will set the day-ahead LMP under the current market rules.

For these reasons, making fast-start pricing revisions to the day-ahead market at this time would not have nearly as significant an impact as implementation in the real-time market. Moreover, the ISO is concerned that undertaking the software changes to address fast-start pricing in the day-ahead market would expand the scope of the implementation phase of this priority project. Making changes to only the real-time market systems at the present time will enable their implementation on a faster schedule, and provide benefits in the real-time markets – where the changes are most needed and will have the greatest benefit.

Q: You indicated that the new pricing method will improve performance incentives for *all* resources. How will it improve performance incentives for resources that transact in the day-ahead market, if the new method is only implemented in the real-time markets?

A: Under the ISO's standard two-settlement energy markets, a resource that clears in the day-ahead market and that fails to perform in real-time – for any reason – is charged the real-time LMP for the MWh deviation between the amount of energy it sells day-ahead and the amount of energy it delivers in real-time. This is generally referred to "buying out" (all or a portion of) its day-ahead energy position.

Under the new fast-start pricing method, all resources will have stronger performance incentives: If a resource that clears in the day-ahead market fails to perform in real-time, and the system must deploy fast-start resources in real-time, the day-ahead cleared resource will have to buy out its day-ahead position at a higher real-time LMP than occurs with the current pricing method. This increases the financial consequences, and therefore the economic incentive, for resources that transact in the day-ahead market to undertake additional investment, maintenance, and operational practices that help assure they can perform during the delivery day.

V. DETAILED DESCRIPTION OF THE FAST-START PRICING CHANGES

Q: What changes are needed to improve the ISO's fast-start pricing method?

A: The ISO is making four closely-related changes to dispatch, pricing, and compensation when fast-start resources are committed and dispatched. With these changes, a fast-start resource may be able to set the real-time LMP when the resource is economically useful for meeting the system's real-time energy and reserve requirements – a much broader range of conditions than those under which fast-start resources are able to set the LMP today.

Q: What do you mean by "when the resource is economically useful" in this context?

A: It means that the system's total production cost is lower with the fast-start resource's output, as dispatched, than it would be under the next lowest-cost alternative without the fast-start resource. When this is the case, operating the fast-start resource improves economic efficiency – or, in simpler terms, the resource is economically useful.

Q: What are the four changes that are being made in this filing to achieve these improvements?

A: I will address each of the four changes in detail below. At a high level, they are: (1) adjusting the real-time dispatch process to satisfy the offered minimum output level of each committed fast-start resource during its initial commitment interval; (2) "relaxing" a pool-committed fast-start resource's minimum output to zero in the pricing process that calculates real-time LMPs and Reserve Market Clearing Prices ("RMCPs"); (3) revising the current treatment of a fast-start resource's Start-Up Fee and No-Load Fee in the pricing process; and (4) providing compensation to resources that, in certain circumstances, may incur a lost-opportunity cost by following the ISO's dispatch instructions when a fast-start resource sets the LMP under the new pricing method.

Q: How will these four changes help to resolve the specific problems you identified previously, in Part III of your testimony?

A: The first major problem that I discussed previously – the fact that fast-start resources infrequently set the LMP, even when they are economically committed, economically dispatched, and the highest-cost resources operating – is addressed directly by the rule changes filed here. As I will describe in more detail, under the revised rules, the pricing (but not dispatch) method will relax an economically-committed fast-start resource's minimum output to zero for the duration of the resource's run time, not just during the initial commitment interval as occurs today. This will allow the pricing algorithm to treat the fast-start unit as marginal, and therefore able to set the LMP, under a broader range of dispatch conditions. As a result, fast-start resources will be able to set the LMP much more frequently than they do today – generally, when their operation is economically useful to the system and they are the highest-cost resources operating at the time. The costs incurred to operate these resources will therefore be more frequently reflected in the real-time energy and reserve markets' prices, improving performance incentives for all resources.

The second major problem that I discussed previously – the potential for the system's dispatch to instruct more total generation than total demand when a fast-start resource is starting up – will be resolved by ensuring that the offered minimum output level of a fast-start resource is satisfied (that is, enforced) during all phases of the commitment and dispatch process. Because the minimum output level is currently satisfied by the dispatch solution *after* a fast-start resource's initial commitment interval, this change will alter the dispatch solution only when a fast-start resource is in its initial commitment interval. Again, I will describe how the instant changes address these problems in greater detail below.

Q: To clarify, pursuant to these changes, the ISO will apply the "relaxation" treatment in the real-time pricing process and not apply any "relaxation" treatment in the dispatch process?

A: Yes. With these changes, the ISO will relax a pool-committed fast-start resource's minimum output level in the real-time pricing process, but it will not relax a fast-start resource's minimum output level in the real-time commitment or dispatch process. This is in contrast to today, where the same relaxation treatment is applied in the pricing process and the dispatch process. Applying these specific and different relaxation treatments in each process is precisely what enables fast-start resources to set price under a broader range of conditions after their initial commitment interval, while enabling the system dispatch to avoid sending over-generation instructions during their initial commitment interval.

Q: You indicated that the new treatment in the real-time pricing process will apply to pool-committed fast-start resources. Does the new pricing method apply only to pool-committed fast-start resources?

A: Yes. As a general matter, fast-start resources can be either pool-committed or self-committed. In simple terms, with a pool-committed resource the initial decision to start the resource is made by the ISO. With a self-committed resource, the initial decision to start the resource is made by the Market Participant.

The pricing process changes in the instant filing will apply only to pool-committed fast-start resources. This is economically appropriate. Under the ISO's energy market design, self-committing a resource indicates that the resource seeks to operate as a price-taker in the energy market for quantities up to its offered minimum output level. Accordingly, it would not be appropriate to extend *price-setting* logic to a resource that seeks to operate as a *price-taking* supplier of its specified minimum output.

Note that, under both the current and revised pricing rules, a self-committed fast-start resource can set the LMP when economically dispatched by the ISO between its offered minimum and maximum output levels.

Q: Will all fast-start resources be subject to the new pricing method?

A: Not initially. There are three types of fast-start resources described in the Tariff: Fast Start Generators, Flexible DNE Dispatchable Generators, and Fast Start Demand Response Resources. The new method will apply to Fast Start Generators and to Flexible DNE Dispatchable Generators, but at this time not to Fast Start Demand Response Resources.

Q: Why will Fast Start Demand Response Resources not be subject to the new pricing method?

A: Completion of another ongoing project – the full integration of demand response resources into New England's wholesale energy markets and reserve markets – is a necessary prerequisite for applying the new pricing method described in this filing to Fast Start Demand Response Resources. That project will implement the more fundamental changes necessary to dispatch and permit demand response resources to set price in the real-time energy market. The Commission has accepted Tariff changes related to that project,[10] but in light of subsequent court decisions,[11] the implementation date of those changes is uncertain at this time.

That uncertainty, however, should not delay the pricing and incentive improvements described here as applied to Fast Start Generators and Flexible DNE Dispatchable Generators. Once the full integration of demand response resources into the energy and

[10] *See ISO New England Inc. and New England Power Pool Participants Committee,* Order Accepting Tariff Revisions, 150 FERC ¶ 61,007 (issued January 9, 2015).
[11] *See Electric Power Supply Association v. FERC*, 753 F.3d 216 (D.C. Cir. 2014)*, cert. granted sub nom. FERC v. Electric Power Supply Association*, 135 S. Ct. 2049 (2015).

reserve markets is implemented, the pricing treatment described here can be extended to Fast Start Demand Response Resources.

Q: Will the new fast-start pricing method apply to any other types of resources?

A: Yes. The new pricing method will also apply to Dispatchable Asset Related Demand resources that meet the same general criteria as fast-start resources (that is, can be started in thirty minutes or less and have a minimum run time of one hour or less). This treatment is appropriate because such assets can reduce real-time energy demand, participate directly in the real-time energy markets today by submitting price-based bids to reduce demand in real-time, and be dispatched in real-time on the same short timeframes as other fast-start resources.

Q: Do the rule changes filed here create any new resource types?

A: No, the changes filed here do not create any new resource types. However, to simplify the new rules, the changes include a new defined term to describe the types of resources to which the new fast-start pricing method applies. The new term "Rapid Response Pricing Asset" is defined as "a Fast Start Generator, a Flexible DNE Dispatchable Generator, or a Dispatchable Asset Related Demand for which the Market Participant's Offer Data meets the following criteria: (i) minimum run time does not exceed one hour; and (ii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes."

Again, a Rapid Response Pricing Asset is not a new type of resource. It is simply a new term that obviates the need to refer to three separate resource types throughout the new pricing rules.

Q: Please describe each of the four changes being filed here in more detail.

A: I will address each of the four changes in turn below.

A. Honoring the Offered Minimum Output Level of a Fast-Start Resource in the Real-Time Dispatch Process

Q: Please explain how a fast-start resource's minimum output level is treated in the real-time processes under the current method.

A: As I discussed previously, the current treatment of a fast-start resource's minimum output level depends on the interval in question. During a fast-start resource's initial commitment interval, the resource's minimum is relaxed to zero in *both* the real-time dispatch process and the associated pricing process. After the initial commitment interval, the resource's minimum output level is enforced for the duration of its minimum run time in both the dispatch and pricing processes.

Q: Please explain the problem with this approach in the dispatch process.

A: The problem with relaxing the minimum output level in the dispatch process occurs during the initial commitment interval. During the initial commitment interval, the dispatch system relaxes the fast-start resource's minimum output level to zero MW. In other words, the dispatch optimization treats the fast-start resource as if it is fully dispatchable between zero megawatts and the resource's *maximum* output level, regardless of the minimum output value submitted in its energy supply offer parameter. Because of this, it is possible that the dispatch system will produce a solution that specifies an output level from the fast-start resource that is greater than zero and *less* than the resource's *minimum* output level.

This dispatch solution, however, does not govern the electronic dispatch signal actually sent to a fast-start resource. To avoid sending infeasible dispatch instructions, in these situations the ISO's real-time systems have additional logic to correct the dispatch instruction sent to a fast-start resource. The corrected dispatch instruction satisfies the resource's offered minimum output level. In other words, even though the economic dispatch solution may call for, say, 30 MW from a fast-start resource at the time of its start-up instruction, if the resource's offered minimum output level is 50 MW, the dispatch instruction electronically sent to the resource will be 50 MW, not 30 MW. In this event, the total generation dispatched in the system will be 20 MW too high, relative to total projected load. This is the system's over-generation instruction problem during the initial commitment interval that I noted earlier in Part III of this testimony.

Q: Why is this over-generation a problem, if it applies only to the dispatch during a fast-start resource's initial commitment interval?

A: To reliably operate the system, total generator output must be constantly balanced with load system-wide. In practice, any over-generation resulting from the dispatch of fast-start resources at levels in excess of those calculated in the economic dispatch solution will typically be offset by other generators that have Automatic Generation Control and are providing Regulation service at the time. However, from an economic perspective, this is often not a least-cost outcome. It would typically be more efficient if the dispatch process did not result in total generation instructions in excess of total projected load in the first place.

Q: How do the instant changes address this problem?

A: Under the revised method, the commitment and dispatch process will be constrained to satisfy a fast-start resource's offered minimum output level throughout its run time, including the initial commitment interval.

Q: How will this resolve the over-generation problem that you described?

A: Because the dispatch solution will be constrained to satisfy the offered minimum output level of each fast-start resource, the dispatch solution will not calculate an output level for a fast-start resource below its offered minimum output level under normal operations. There will no longer be any need for the special logic to correct the dispatch instruction electronically sent to a fast-start resource in order to avoid sending it an infeasible dispatch level. As a direct consequence, under the revised method, the potential over-generation instructions problem will no longer occur when a fast-start resource is initially committed. This treatment will resolve the potential inefficiencies associated with relying on other generators on Automatic Generation Control providing frequency "regulation down" service to counterbalance the potential over-generation when fast-start resources are started.

B. Relaxing the Minimum Output Level of a Committed Fast-Start Resource in the Pricing Process

Q: Please explain how a fast-start resource's minimum output level is treated in the real-time pricing process under the current method.

A: Under the current method, a fast-start resource's minimum output level is treated the same way in the pricing process as it is in the dispatch process (as discussed above). In a pricing interval associated with the initial commitment interval, a fast-start resource's minimum output level is relaxed to zero MW; in a pricing interval after the initial commitment interval, the resource's offered minimum output level is enforced for the duration of the resource's minimum run time.

Q: Please explain the problem with this approach in the pricing process.

A: It is this feature of the current method that commonly precludes a fast-start resource from setting price after the initial commitment interval, even when the resource is economically committed and economically dispatched throughout its run time. Because fast-start resources are "lumpy," they are dispatched (after the correction is applied during the initial commitment interval) to at least their minimum output levels – which are commonly equal, or close, to their maximum output levels. As noted previously in Part III of this testimony, when a resource is economically dispatched to its minimum output level it is typically because there is another generator, with a lower incremental cost, that would be dispatched instead to meet incremental demand. In these situations, the pricing algorithm typically determines that the fast-start resource's dispatch would not change to meet incremental demand – that is, the fast-start unit is not a marginal resource in the pricing process. As a consequence, fast-start resources generally do not set the LMP after their initial commitment interval, even when they are economically committed, economically dispatched to their minimum output level, and the highest-cost resources supplying power in the system.

Q: How do the instant rule changes address this problem?

A: Under the revised rules, the LMPs and RMCPs will be calculated in the real-time pricing process by relaxing a pool-committed fast-start resource's minimum output level to zero throughout its run time. That is, the minimum output level will be relaxed both during its initial commitment interval (as occurs today) and after its initial commitment interval (the change from the current method).

Importantly, the fast-start resource's minimum output level will be relaxed to zero only in the real-time pricing process. As explained in Part V.A. above, the resource's minimum output level will not be relaxed in the real-time dispatch process. Although both the real-time dispatch and real-time pricing processes use nearly identical computational algorithms, the resource-specific numerical inputs to the two processes will, under the new pricing method, generally specify different values for the minimum output level of a fast-start resource – zero for the pricing process, and the offered minimum output level for the dispatch process.

Q: How will this resolve the pricing problems that you have described?

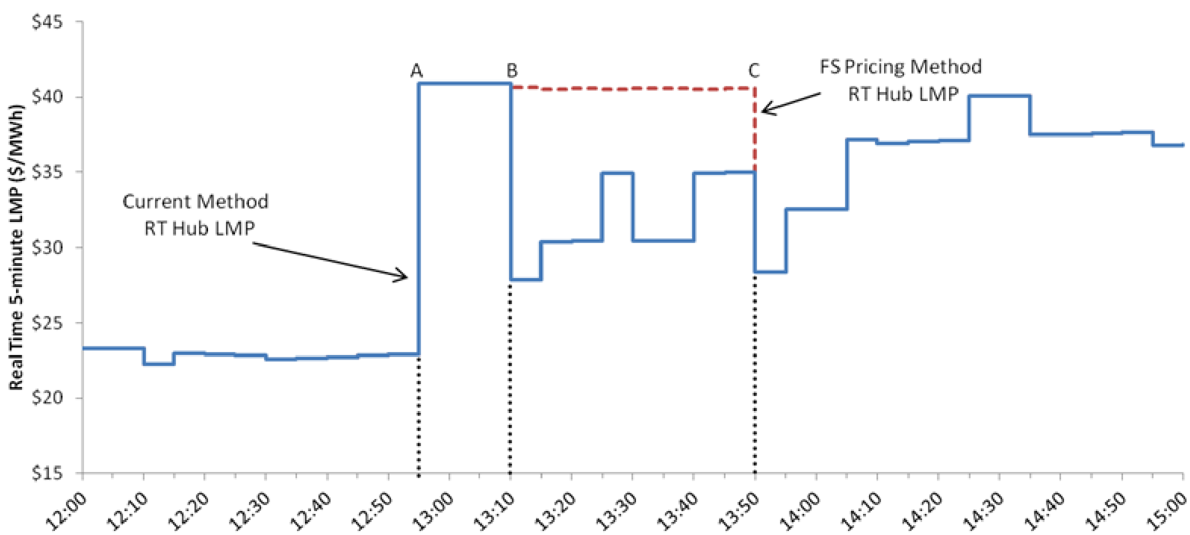
A: Relaxing the fast-start resource's minimum output level to zero in the real-time pricing process throughout the resource's run time will enable the pricing algorithm to treat a committed fast-start unit as the marginal resource, and therefore potentially able to set price, under a broader range of dispatch conditions than the current pricing method. Generally, these conditions correspond to the concept of a resource being economically useful for meeting the system's real-time energy and reserve requirements.

Q: Please explain the "economically useful" concept further.

A: The changes filed here will make it more likely (relative to the current pricing method) that committed fast-start units will set the LMP. However, this does not imply that that a committed fast-start unit will necessarily set price when it has a higher cost than all other operating units. Rather, a committed fast-start resource may set the LMP when it has the highest cost among all resources operating at the time, and the fast-start resource is economically useful in this dispatch interval in the sense noted previously: the power system's total production costs are lower with the fast-start resource than total production costs would be under the lowest-cost alternative without the fast-start resource.

Q: Can you please provide an example contrasting the current and revised real-time pricing methods?

A: Yes. The graph below shows the real-time five-minute LMPs between 12:00 and 15:00 on August 19, 2014. A fast-start resource was committed just before 12:55. The solid blue line depicts the real-time Hub LMP under the current method; the dashed red line depicts how the real-time LMP would differ under the new method in this filing.



The particular fast-start resource committed just before 12:55 has some dispatchable range (that is, its offered minimum output level is less than its offered maximum output level), and was dispatched between its offered minimum and offered maximum output levels for the three five-minute pricing intervals from 12:55 to 13:10 (shown in the graph as points A and B, respectively). As a consequence, this fast-start resource was marginal and set the LMP between points A and B, under the current pricing method.

The difference between the two pricing methods can be seen between point B and point C. From point B to point C, this fast-start resource was dispatched at its offered minimum output level (which is a value significantly greater than zero MW). Under the current pricing method, as shown by the blue line, the fast-start resource did not set the LMP during this period. Instead, other online resources – with lower incremental energy offer prices than the now-online fast-start resource – set the LMP during the eight five-minute real-time pricing intervals from point B to point C. As previously explained, this is because the current real-time pricing process did not treat this fast-start resource as the marginal resource after point B. That is, under the current method, even though this fast-start resource was economically committed, economically dispatched, and had a higher cost than other resources operating at the time, it did not set the price for the majority of its minimum run time (*viz.*, from point B to point C).

The dashed red line in this graph depicts the LMP as it would have been calculated under the revised rules in the instant filing. Under the new pricing method, the fast-start resource's minimum output level is satisfied by the dispatch process, but it is relaxed to zero in the pricing process as long as the resource remains pool-committed. With its minimum output level treated as zero in the pricing process, the new pricing method would continue to treat this fast-start unit as a marginal resource from 13:10 to 13:50. Thus, with the new pricing method, the LMP would be set – incorporating the fast-start resource's higher cost – at the dashed red line between point B and point C. Because this resource was economically useful throughout its minimum run time, and had a higher cost than other resources operating at the time, the new method sends a market price signal reflecting this fast-start resource's higher cost.

At the end of the fast-start resource's minimum run time (at approximately point C), this resource was no longer economically useful for meeting the system's energy and reserve requirements. Under both the current and new pricing methods, the real-time prices – as shown by the solid blue and dashed red lines – converge after point C, and other system resources set the real-time LMP thereafter.

Q: Why does the price on the graph appear to vary slightly between points A and C?

A: It is tempting to expect a perfectly horizontal line between points A and C on the graph under the new pricing method, reflecting the fast-start resource's offer price during that time. However, the real-time Hub LMP shown here incorporates the cost of energy losses and congestion, which vary slightly in each five-minute pricing interval.

Q: You mentioned that under the revised rules, the pricing process will also relax a fast-start resource's minimum output level in the calculation of reserve market clearing prices. How will that affect reserve market clearing prices?

A: Reserve prices will continue to be set by the opportunity cost of supplying reserves, rather than energy, in real-time. However, because energy prices will change – when set by a fast-start resource – the opportunity cost of supplying reserves instead of providing energy will change accordingly. Under both the current and the new pricing methods, the opportunity cost of supplying reserves instead of energy will continue to determine all real-time RMCPs.

In other words, because energy prices will change when set by a fast-start resource, the results of co-optimized real-time energy and reserve pricing will change accordingly. In general, this will tend to increase not only the real-time price for energy, but also the real-time price for reserves: when the energy price increases, the opportunity cost of supplying reserves instead of energy generally increases, and consequently the price that must be paid for reserves generally increases. This does not result from a change to the existing co-optimization logic that jointly determines real-time energy and reserve prices; it is merely a consequence of the changes to real-time energy prices that will result from the revised method.

Q: Under the new pricing method, will fast-start resources set the LMP in all of the pricing intervals when they operate?

A: No. While the revised method will allow fast-start resources to set the price under a wider range of conditions, there are situations in which a pool-committed fast-start resource may be operating but will not set the price. Broadly, this may occur for two reasons. First, a fast-start resource may not set the price if another, higher-cost resource does so. In this case, the fast-start resource is infra-marginal and, in a uniform clearing-price market, the infra-marginal supplier does not set the market-clearing price.

Second, an operating fast-start resource will not set the price during intervals when the new pricing process, which will treat the fast-start resource's minimum output level as zero, determines that the fast-start resource's economically optimal output level is zero. In this situation, the pricing process indicates the resource is no longer economically useful for meeting the system's energy and reserve requirements – and from an economic perspective, it should be released for shutdown. The fast-start resource will not set the price in this situation, even if it cannot yet be shut down by the ISO's dispatch process because the resource has not completed its minimum run time. This is an important component of the revised design, ensuring that the energy market's price signal does not reflect the higher costs of a fast-start resource if the new pricing process indicates that the fast-start resource is no longer economically useful. Furthermore, this treatment helps to avoid creating perverse incentives for fast-start resources to offer increased minimum run times, and – over time – may actually provide incentives for fast-start resources to undertake operational improvements to enhance their flexibility and to reduce their minimum run times.

C. Revising the Treatment of a Fast-Start Resource's Commitment Costs

Q: What are a fast-start resource's "commitment costs," generally?

A: A fast-start resource provides the ISO with three costs as part of its Supply Offer: (1) the resource's incremental energy offer (in dollars per megawatt-hour); (2) its Start-Up Fee (in dollars per start); and (3) its No-Load Fee (in dollars per hour). Collectively, the Start-Up Fee and the No-Load Fee are commonly referred to as a resource's "commitment costs." The treatment of these separate costs, and their effects on real-time prices, depends on timing. As I will explain further, under the current practice the resource's commitment costs may be incorporated into the LMP during the initial commitment interval, but are not incorporated in the LMP during subsequent intervals.

Q: Please describe how a fast-start resource's commitment costs are treated currently in the pricing process.

A: In the current real-time pricing method, the Start-Up Fee and No-Load Fee of a fast-start resource are incorporated into the real-time price calculation during the resource's initial commitment interval. Specifically, the pricing process first calculates an "adjusted" incremental energy offer for each fast-start resource. This adjusted incremental energy offer combines the submitted incremental energy offer price with the resource's commitment costs. The pricing process calculates LMPs and RMCPs during the initial commitment interval using the fast-start resource's adjusted incremental energy offer, instead of the incremental energy offer alone.

Specifically, to determine the adjusted incremental energy offer, the fast-start resource's commitment costs are combined with its incremental energy offer as follows.

The resource's Start-Up Fee is amortized (that is, averaged) over the product of the resource's maximum output level (in MW) and one hour; the resource's No-Load Fee is amortized over the resource's maximum output level; and the resulting values are added to the resource's incremental energy offer price. The sum total is the resource's adjusted incremental energy offer price.

As a simple example, assume a fast-start resource with a 50 MW maximum output submits the following offer parameters:

- an Incremental Energy Offer of $100 per MWh;
- a Start-Up Fee of $150 per start; and
- a No-Load Fee of $100 per hour.

This resource's amortized start-up is calculated as:

- $150 / (50 MW × 1 hour) = $3 per MWh.

This resource's amortized no-load is calculated as:

- $100 per hour / 50 MW = $2 per MWh.

The resource's adjusted incremental energy offer price is the sum of the incremental energy offer price, the amortized start-up, and the amortized no-load, which is:

- $100 per MWh + $3 per MWh + $2 per MWh = $105 per MWh.

During the resource's initial commitment interval, the pricing process would employ this $105 per MWh value as the marginal cost of energy supplied from this fast-start resource in the calculation of real-time LMPs and RMCPs.

Q: Under the current pricing method, are the fast-start resource's commitment costs incorporated into the pricing process *after* the resource's initial commitment interval?

A: No. Under the current pricing method, a fast-start resource's commitment costs are not considered at all in the pricing process after its initial commitment interval. The pricing process after the initial commitment interval is based on only the resource's incremental energy offer, and the resource's commitment costs are ignored.

Q: As a fundamental matter, why is it beneficial to incorporate these commitment costs into the pricing process for fast-start resources at all?

A: There are several reasons why incorporating commitment costs into the pricing process can be beneficial. First, this practice further strengthens resources' performance incentives when they matter most. Most fast-start resources are infrequently committed and dispatched, but they are typically instructed to start during stressed system conditions when no alternate, lower-cost resources are available. In these conditions, the system may be experiencing a combination of severe weather, unplanned outages, gas pipeline problems, higher than forecast load, or steep ramping needs. These are precisely the times and conditions when resource performance, from all units, is crucial. Sending strong price signals during these conditions is essential to provide financial incentives for performance to all resources. By incorporating the commitment costs of fast-start resources into their incremental energy offer prices and thereby into the real-time LMP, the incentives for all resources to perform during stressed system conditions are enhanced.

Second, adjusting fast-start resources' incremental energy offers by their amortized commitment costs promotes price transparency. This is achieved when a greater percentage of the total revenues earned by resources passes through transparent energy market price signals, rather than through non-transparent, resource-specific, out-of-market uplift (NCPC) payments. Adjusting incremental energy offers by amortized commitment costs lowers the total NCPC to all resources, because it results in higher real-time prices for all operating resources when a fast-start resource sets the LMP.

Finally, if commitment costs are not incorporated into the pricing process, fast-start resources may have an incentive to lower their submitted Start-Up Fee and No-Load Fee and raise their submitted incremental energy offer prices by an offsetting amount. This could result in inefficient dispatch solutions for the system. Specifically, when evaluating whether it is efficient to continue operating an online fast-start resource beyond its minimum run time, or whether it is more efficient to release the resource for shutdown, the ISO's dispatch system needs to have the actual incremental energy costs of the fast-start resource. If resources have incentives to submit incremental energy offers that already incorporate their commitment costs, rather than to submit the commitment costs separately (and let the ISO make use of this commitment cost information appropriately in the dispatch and pricing processes), it could impede efficient outcomes when the ISO's dispatch system makes unit shutdown or extended-run time decisions for fast-start resources.

For all of these reasons, it is appropriate and beneficial to incorporate a fast-start resource's commitment costs into its incremental energy offer. Indeed, as explained below, in several respects the current method does not go far enough.

Q: Please explain the ISO's concerns with the current approach for incorporating a fast-start resource's commitment costs into the pricing process.

A: There are two general concerns with the current approach to incorporating the Start-Up Fee and No-Load Fee into a fast-start resource's incremental energy offer. First, amortizing the Start-Up Fee over a fixed period of one hour, despite considerable variation in the minimum run times of fast-start resources, is arbitrary and not economically justified. Fast-start resources in New England can, and do, have minimum run time offer parameters of less than one hour. Second, and more importantly, under the current method these commitment costs affect real-time prices only during a fast-start resource's initial commitment interval. As a result, the energy market's price signal fails to reflect the costs incurred to operate a fast-start resource during periods after the initial commitment interval, when the resource's operation may continue to be economically useful.

Q: What is a more appropriate period for amortizing a fast-start resource's Start-Up Fee?

A: A resource's Start-Up Fee is a marginal cost before the resource is committed. After the resource is committed, the Start-Up Fee is a sunk cost. Because the start-up decision is instantaneous (given modern software), a practical issue arises regarding the period of time over which the start-up cost should be amortized. Economic theory does not provide a precise answer, but provides a partial guide: Because the start-up costs are marginal when the resource is committed, they should be incorporated into prices – at a minimum – at the time the resource is started. This serves as a price signal to the markets about the costs of the marginal action being undertaken to operate the power system economically in real time.

Instead of using a fixed and arbitrary duration of one hour, the revised method will amortize a fast-start resource's Start-Up Fee over the resource's minimum run time. This means that a fast-start resource's Start-Up Fee will be amortized over a resource-specific time period ranging from a minimum of 15 minutes to a maximum of one hour (because one hour is the maximum value of the minimum run time allowed for a fast-start resource in the Tariff).

Observe that with this revised Start-Up Fee amortization approach, a resource that is economically committed and dispatched to its maximum output level for the duration of its minimum run time will not require an uplift (NCPC) payment to cover the costs it incurs to start, as its start-up cost will be covered by the market price for energy. Further, by setting the Start-Up Fee amortization period based on the (resource-specific) minimum run time, the revised approach avoids creating situations in which a marginal fast-start resource would recover more than the full amount of its Start-Up Fee if it continues to operate economically after the end of its minimum run time. This is because the amortized Start-Up Fee will be incorporated into the resource's adjusted incremental energy offer only before the resource completes its minimum run time, and not incorporated thereafter.

Q: Is the period for amortizing a fast-start resource's No-Load Fee the same?

A: No. Under the revised approach, the treatment of the No-Load fee is similar, but not exactly the same. While the Start-Up Fee is a fixed dollar amount incurred when the resource starts to operate, the No-Load Fee is a continuous rate when the resource operates. That is, if it is economical to continue operating a fast-start resource after its minimum run time, the resource continues to incur its no-load cost. (This difference between the two is exemplified by the fact that the Start-Up Fee is denominated in dollars per start, while the No-Load Fee is denominated in dollars per hour.)

Q: Please summarize the specific changes to the treatment of these commitment costs in the pricing process under the revised pricing method.

A: In the pricing process, under the revised method, the No-Load Fee of a fast-start resource will be amortized over the resource's maximum output (as is performed currently) and then incorporated into (that is, added to) its incremental energy offer price throughout the resource's actual run time (a change from current practice).

As indicated above, the Start-Up Fee of a fast-start resource will be amortized over the resource's maximum output and the resource's minimum run time (instead of over one hour, as is the current practice), and the amortized value will be incorporated into (that is, added to) the resource's incremental energy offer price throughout the resource's minimum run time.

Thus, under the revised method, a fast-start resource's adjusted incremental energy offer price will be the sum of its incremental energy offer and its amortized no-load value and, during its minimum run time period, its amortized start-up value.

It is important to note that these adjustments to a fast-start resource's incremental energy offer will be performed in the pricing process only. The real-time commitment and dispatch process does not combine these values in its optimization routines to determine whether to commit a fast-start unit, and the dispatch process will use only the incremental energy offer (without adjustments) to determine the system's dispatch solution and the dispatch instruction sent to a fast-start resource.

Q: How will the revised treatment of fast-start resources' commitment costs address the problem that you described earlier?

A: Incorporating the Start-Up Fee and No-Load Fee in this manner will improve price signals in the energy market by reflecting the costs incurred to operate fast-start resources that are economically useful for meeting the system's real-time energy and reserve requirements. This will help to improve price transparency, and will serve to strengthen performance incentives for all resources during operating conditions when performance tends to matter the most.

Moreover, in conjunction with the changes to the treatment of a fast-start resource's minimum output parameters in the pricing process described previously in Part V.B, these revisions to the treatment of a fast-start resource's commitment costs will have a helpful impact well beyond the fast-start resource's initial commitment interval because fast-start resources will be able to set price more frequently after their start-up interval than they do today.

D. Providing Compensation for Lost-Opportunity Costs

Q: You stated earlier that these revised rules provide compensation for lost-opportunity costs in certain circumstances when a fast-start resource sets the LMP. What lost-opportunity costs arise when a fast-start resource sets the LMP under the new pricing method?

A: As explained previously, under the revised method a fast-start resource's minimum output level will be enforced in the dispatch process. Broadly, if a fast-start resource is dispatched to its minimum output level, and this minimum output level exceeds the additional output required to meet demand, then the dispatch solution must also simultaneously re-dispatch other online resources. In this case, the system's dispatch solution may balance total supply and total demand by "posturing down" one (or possibly several) lower-cost online generators. By "posturing down," I mean that one or more online resources may be dispatched to an output level that is less than their profit-maximizing output level when the fast-start resource sets the LMP. In this situation, an online resource dispatched below its profit-maximizing output level incurs a lost-opportunity cost by following its dispatch as instructed.

Q: Can you please provide a simple example explaining how this lost-opportunity cost may arise?

A: Yes. Imagine that an online, non-fast-start resource sets the real-time LMP at its energy offer price of $20 per MWh. Suppose now that demand increases by 5 MW, and that the least-cost means to satisfy the increase in total demand is to start a particular fast-start resource and dispatch it to its minimum output level of 20 MW. Suppose further that, under the revised pricing method, this fast-start resource now sets the real-time LMP at $100 per MWh.

Since the additional output from the fast start resource is 20 MW but the additional demand is only 5 MW, the real-time dispatch system will simultaneously re-dispatch down 15 MW of online generation to balance total supply and total demand. Suppose now that the $20 per MWh online non-fast-start resource is the unit dispatched down by 15 MW (from its output level before demand increased). By construction, this online non-fast-start resource is capable of producing 15 MW more than its new dispatch instruction, and can do so at an energy offer price of $20 per MWh – which is well below the $100 per MWh LMP it now faces. If the online, non-fast-start unit were to deviate from its dispatch by producing more than its new dispatch instruction, it would earn an additional $80 per MWh "deviation margin" ($100 LMP – $20 energy offer) on each MWh it produces.

This "deviation margin" creates a lost-opportunity cost. Specifically, if the online non-fast-start unit deviated from its dispatch instruction by 15 MW (*e.g.,* it maintains the same output level as at the outset of this example despite receiving a new, lower dispatch instruction), then the non-fast-start unit would increase its net revenue over (say) the next half-hour, assuming all else remains constant, by $600:

- 15 MW deviation × ($100 LMP – $20 energy offer) × ½ hour = $600.

Put in simple terms, by *following* its new dispatch as instructed after a fast-start resource sets the LMP, the online non-fast-start resource in this example incurs a lost-opportunity cost of $600 over the next half-hour.

Q: Why is that a problem?

A: Resources dispatched below their profit-maximizing real-time output level in this manner incur a lost-opportunity cost by following their dispatch instruction while facing a rising price, which diminishes their economic incentive to follow the dispatch instruction. Stated more directly, unless this opportunity cost is properly addressed by the market design, an affected resource may perceive a strong financial opportunity to increase its profit by increasing its real-time output above its dispatch instruction. This is not only economically inefficient – because generators may find it profitable to no longer execute their part of the least-cost dispatch for the power system – it can result in an imbalance of power supply and demand and, over time, undermine the ability and confidence of system operators to assure reliable system operation.

Q: How is this lost-opportunity cost issue addressed by the revised market design?

A: Under the revised rules, certain resources "postured down" in these specific circumstances will be compensated for their lost-opportunity costs. This will eliminate the potential financial incentive for a resource to not follow its dispatch instruction that may otherwise arise when a "lumpy" fast-start resource sets the real-time LMP.

Q: Is there any precedent for lost-opportunity cost payments in the ISO's real-time markets?

A: Yes. The ISO directly compensates resources for lost-opportunity costs in other circumstances under the currently effective Tariff. For example, in the ISO-administered Regulation market, units providing frequency regulation service may incur a lost-opportunity cost of not supplying energy when their real-time regulation signal sends the unit down (to reduce its energy output) despite a high real-time energy price. This form of lost-opportunity cost for units providing regulation service is analogous to the lost-opportunity cost incurred by online resources "postured down" when a fast-start resource sets the LMP, under the revised rules filed here. That is, in both situations, a resource may incur a lost-opportunity cost when, to balance the system's total energy supply and demand, it is necessary to instruct the resource to lower its energy output during a period when another, higher-cost resource sets the market price for energy.

Q: Aren't resources already required to follow the ISO's dispatch instructions, and if so, aren't these new lost-opportunity cost payments unnecessary?

A: As a basic principle of sound market design, it is important for market rules – and the compensation the rules provide – to ensure that resource owners' private, profit-maximizing incentives are properly aligned with the specific dispatch instructions issued to achieve reliable and least-cost system operations. If they do not, resource owners may have undesirable and adverse incentives to take actions that inhibit reliable and least-cost operations, and to test the boundaries of non-market enforcement mechanisms.

A simple analogy may be helpful. In the United States, highway speed limits are the law of the land. Yet, even to causal observation, it is evident that many drivers routinely exceed them. It is only practical to detect, stop, ticket, and prosecute the most egregious speeders – and, knowing as much, these practicalities leave other drivers with little inhibition from traveling modestly over the posted speed limit.

Unlike the impact of modestly speeding drivers, however, if generation operators in the power system modestly exceed the limit they have been instructed to follow, there could be significant ramifications – such as difficulty maintaining supply and demand balance within mandatory reliability standards. Without the lost-opportunity cost payments provided for under the revised rules in the instant filing, there is clear financial incentive for resources to deviate from dispatch instructions, or to respond slowly. It is far superior to eliminate the incentive to deviate from dispatch instructions through the sound application of market design than it is to merely attempt to "prosecute" the truly egregious offenders. Properly designed incentives and associated compensation rules will ensure that the entire fleet is motivated to properly follow their dispatch instructions.

Q: But couldn't the same incentives be achieved by imposing Tariff-based penalties on resources that do not follow real-time dispatch instructions, instead of making the payments for lost-opportunity costs that you describe?

A: In principle, explicit penalties for deviations from dispatch are a possible means to provide resource owners with financial incentives to follow dispatch. But again, imposing penalties for otherwise profitable actions is never going to be as effective as taking the profit out of the action in the first place. Moreover, the penalty approach has other, adverse incentive effects that could undermine resource flexibility and system operational capabilities.

Specifically, if there are significant penalties for deviations from dispatch instructions, then a resource owner may find it profitable to minimize its penalty exposure by either: (1) self-scheduling its output more frequently, so that it receives fewer dispatch instructions to change output; or (2) increasing its minimum output level over time, so that the ISO's dispatch system does not dispatch that owner's resource down when a "lumpy" fast-start resource may be started and set price – which increases the owner's profit by avoiding its *de facto* lost opportunity cost. These behaviors are plainly inefficient, will reduce operational flexibility, and over time the reduced flexibility may increase the cost of operating the power system. At bottom, implementing express penalties for not following dispatch instructions is far less efficient and more fraught with potential problems than simply removing the incentive to deviate from dispatch instructions in the first instance – which is precisely what the ISO's revised rules will accomplish via carefully-calibrated lost-opportunity cost payments.

Q: Are these lost-opportunity cost payments to resources postured down under the revised method preferable to the current practice of using Automatic Generation Control to address over-generation that occurs under the current method?

A: Yes. While both methods broadly address the problem of mis-matched energy supply and demand when "lumpy" generators (such as fast-start resources) set price, the new method is preferable. Under the current method, dispatch instructions do not properly balance supply and demand during the initial commitment interval, and so Automatic Generation Control, and the associated payments, are used to correct the imbalance *after* it occurs. Under the revised approach, dispatch instructions properly balance supply and demand, and lost-opportunity cost payments are used to avoid an imbalance *before* it occurs. To continue using the current approach when fast-start resources are able to set price under a much broader range of operating conditions would result in imbalanced power system dispatch instructions far more frequently than occurs today – an adverse outcome that is easily avoided using the revised method and lost-opportunity cost compensation.

Q: Does the lost-opportunity cost payment constitute a "double" payment?

A: No. It only provides compensation for net revenue that could have been earned by not following dispatch instructions in certain circumstances. It does not pay resources a "second time" for the energy delivered. Nor does it pay for costs not incurred, such as fuel not burned. Lost-opportunity cost corresponds to the net revenue foregone by following the ISO's dispatch as instructed.

Q: Which resources will be eligible to receive a lost-opportunity cost payment?

A: Lost-opportunity cost payments will be paid to a resource that is "postured down" to balance the system when a fast-start resource sets the LMP at a value higher than the resource's energy price offer. Resources that are not dispatchable would not be postured down by the dispatch system in these situations, so it is appropriate that no lost-opportunity cost payments will be calculated or provided to resources that are not dispatchable in real-time. Accordingly, no lost-opportunity cost payments are to be provided to Settlement Only Resources, Demand Response Resources, or External Transactions. In addition, to avoid duplicative credits to resources that may receive lost-opportunity cost compensation through other, existing provisions of the Tariff, there is an exception for any resource that has been Postured (pursuant to other provisions of the Tariff), or that provides Regulation service during the same hour.[12]

Q: Can a resource increase its lost-opportunity cost payment by producing less than its dispatch instruction?

A: No. The amount of the payment will be calculated, generally, as the difference between what the resource would have earned for energy and reserves absent being postured down (its "economic net revenue") and what the resource actually earned for energy and reserves (its "actual net revenue"). Importantly, however, the payment is calculated such that a resource incurring a lost-opportunity cost cannot increase the payment by producing less than instructed. In the Tariff, this is provided for by calculating the impacted resource's "actual net revenue" based on the greater of the net revenue associated with its real-time dispatch level and the net revenue associated with its real-time energy output level.[13] In this way, a resource cannot increase its lost-opportunity cost payment by producing less than its dispatch instruction.

[12] *See* new Tariff Section III.F.2.3.10.1.
[13] *See* new Tariff Section III.F.2.3.10.3.

Q: Have you estimated the potential magnitude of the lost-opportunity cost payments?

A: Yes. As an initial matter, it is helpful to understand that the magnitude of the lost-opportunity cost payments when a fast-start resource sets the LMP is inherently limited because only a small number of megawatts are affected. Specifically, the total MW that may incur a lost-opportunity cost (system-wide) is, at most, equal to the aggregate minimum output level of the fast-start resources operating at the time. For instance, if there are two fast-start resources operating and the sum of their minimum output levels is 20 MW, then the total MW that may be "postured down" on other online generators and incur a lost-opportunity cost is – at most – 20 MW system-wide. This property holds because the lost-opportunity cost compensation only applies to the extent that an online resource is postured down to accommodate the minimum output levels of the fast-start resources in current operation.

More specifically, the ISO has conducted a detailed impact analysis of the instant changes to the fast-start resource pricing method, which I will discuss in more detail presently. In brief, using data from 2014, we estimate that had the revised method in this filing been in effect during 2014, the total lost-opportunity cost payments would have been approximately $3.2 million. As I will explain, these payments are much less than – that is, they are more than offset by – the considerably larger reductions in total real-time NCPC payments to fast-start and non-fast-start resources resulting from these pricing improvements.

VI. ANTICIPATED ECONOMIC IMPACTS

Q: What has the ISO done to assess the potential impacts of these fast-start pricing improvements?

A: The ISO performed a detailed impact analysis of these changes to fast-start pricing in the real-time energy and reserves markets, under my supervision. This analysis consisted of re-running the ISO's production-level dispatch and pricing software, with modifications to perform the new fast-start pricing method, using system data from 2014. While 2014 may or may not be representative of future conditions, it is informative to compare the actual outcomes from that time period to the simulated results that would have occurred during 2014 using the new fast-start pricing method.

Specifically, we re-ran the ISO's production-level real-time pricing algorithm – as modified per the revised method – for all pricing intervals in which one or more eligible fast-start resources were committed (there would be no change to the pricing process in the other intervals). Approximately 15,000 real-time dispatch cases met this criterion, out of approximately 58,000 total dispatch cases in the study period. The five-minute simulated real-time prices computed under the new pricing method were aggregated into hourly LMPs and RMCPs, for comparison to the actual hourly LMPs and RMCPs under the current pricing method.

Q: Please describe the results of that analysis.

A: Our analysis indicates that, had the fast-start pricing changes described here been in place during 2014, there would have been modest overall impacts on real-time market settlements. These consist of increases in the real-time energy charges to load deviations and increases in real-time reserve payments of approximately $20.5 million and $11.6 million, respectively, and approximately $3.2 million in lost-opportunity cost payments (as I noted previously).

The estimated change in the average annual real-time system energy price during the study period, as a result of these pricing improvements, is $3.10 per MWh. Importantly, the impact on real-time prices occurs in only approximately 30 percent of all hours during the 2014 study period. In approximately 70 percent of the hours, the revised fast-start pricing method resulted in no change to the hourly LMP. This is because fast-start resources generally have low annual capacity factors, and no fast-start resources are in operation during most hours of the year.

Q: And what is the overall effect of this change on out-of-market payments?

A: In general, there is a trade-off between: (a) total make-whole payments to resources, which decrease the more often fast-start resources set price, and (b) lost-opportunity cost payments, which increase the more often fast-start resources set price. This tradeoff is inescapable, in both theory and practice, because of the “lumpy” nature of fast-start resources. However, with good market design and careful simulation studies, it is possible to improve upon current pricing practices in a way that reduces the total of these aggregate out-of-market payments. This reduction is what we expect to come of the fast-start pricing changes presented here, and what our detailed simulation study results indicate.

Specifically, the estimated reduction in total real-time NCPC in 2014 that would have resulted from the improved method presented here (after accounting for the impact of other NCPC-related rules implemented since that time) is approximately $17.2 million. This is comprised of an estimated reduction in the real-time NCPC paid to fast-start resources of $7.1 million, and an estimated reduction in the real-time NCPC paid to non-fast-start resources of $10.1 million (attributable to the higher real-time LMPs and RMCPs when fast-start resources set price). As noted immediately above, the estimated total lost-opportunity cost payments amount to $3.2 million. Thus, during our 2014 study period, we estimate a net reduction in total real-time out-of-market payments of $14 million ($17.2 million minus $3.2 million).

Q: Did you study the potential impacts of the revised fast-start pricing method on the day-ahead energy market or the forward capacity market?

A: We did not perform a simulation study of the effect of these changes on the ISO's forward markets, such as the day-ahead energy market or the forward capacity market. However, qualitatively speaking, economic theory predicts that over time, increases in real-time LMPs will be reflected in day-ahead LMPs as buyers adjust the amount of energy they purchase in the day-ahead energy market until the day-ahead and real-time energy markets reach price parity, at least on an average annual basis. This implies that day-ahead energy prices will tend to rise, over time, as a result of these changes to the fast-start pricing method in the real-time energy market.

By the same logic, increases in day-ahead energy prices will tend, over time, to lower prices in the forward capacity market. This is because increases in energy market revenue reduce the amount of "missing money" that suppliers must recover in the capacity market. In principle, over time the reductions in capacity payments may fully offset the impact on energy market payments resulting from the fast-start pricing improvements, though this is difficult to assert with certainty due to the many factors affecting future capacity prices.

In any case, these reforms will ultimately help to shift, incrementally, the total revenue stream received by supply resources from the capacity market to the energy and reserves markets. Doing so will serve to improve the markets' overall performance incentives, since energy market revenue is paid only to resources that perform. The ISO's External Market Monitor indicated as much in its 2013 Market Assessment, stating that "[a]llowing peaking resources to set prices when marginal would also improve . . . [i]ncentives governing longer-term investment and retirement decisions by participants, since it would provide increased net revenues to generators that are available during tight operating conditions. This would, in turn, reduce the required net revenues from the capacity market."[14]

[14] 2013 Market Assessment at p. 95 (footnote omitted).

VII. <u>CONCLUSION</u>

Q: Does this conclude your testimony?

A: Yes.

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

Executed on September 24, 2015.

Matthew White

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Matthew White, Chief Economist

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.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

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.

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. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net 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.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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 each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2018, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

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 July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity 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 Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service 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 July 14, 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 Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in the rules filed with the Commission on January 17, 2014, and accepted by the Commission on May 30, 2014.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer 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.

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.

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.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by (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 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 estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving

Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(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, 2018, 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, 2018.

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 Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead 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, 2018, 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 an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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 Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

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, 2018.

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 Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and 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 (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points and meets the criteria specified in Section III.1.11.3(e).

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator 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 below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output level to which a Resource would have been dispatched, based on the Resource's Supply Offer and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a 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 (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

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.

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 Offer Cap is $1,000/MWh.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours 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.

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 Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically~~; and (vi) has satisfied its Minimum Time Between Reductions~~.

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) ~~m~~Minimum ~~r~~Run ~~t~~Time does not exceed one hour; (ii) ~~m~~Minimum ~~d~~Down ~~t~~Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; and (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.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes~~; and (iv) has satisfied its Minimum Down Time~~.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; and (iv) has satisfied its Minimum Down Time.

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 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.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

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, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the "Large Generator Interconnection Procedures", the "Small Generator Interconnection Procedures", or the "Elective Transmission Upgrade Interconnection Procedures" pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

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.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means 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 Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is 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 or a Public Policy Transmission 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, 2018, 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, 2018, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

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. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

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 Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

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 Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

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 calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity 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.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

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-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-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.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

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.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(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 Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization’s activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity

Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand 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.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is a Fast Start Generator, a Flexible DNE Dispatchable Generator, or a Dispatchable Asset Related Demand for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Run Time does not exceed one hour; and (ii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

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 NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(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, 2018, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2018.

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 Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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 Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(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 Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 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 Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or 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 Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2018, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

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, 2018, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation 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 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. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable

Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. 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: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

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.

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).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a 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. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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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 (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate 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 (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart 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 Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

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. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices 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. 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 power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 ~~[Reserved .]~~ Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee or No-Load Fee is specified in the submitted Offer Data, a value of zero shall be used, and if no Minimum Run Time or minimum consumption time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or minimum consumption time is less than 15 minutes, a duration of 15 minutes shall be used.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand, its Minimum Consumption Limit shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has not satisfied its minimum consumption time, its energy offer shall be decreased by: (i) the Start-Up Fee divided by the product of the Maximum Consumption Limit and the minimum consumption time; and (ii) the No-Load Fee divided by the Maximum Consumption Limit.

(e) If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has satisfied its minimum consumption time its energy offer shall be decreased by the No-Load Fee divided by the Maximum Consumption Limit.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response 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.2.7A(c)~~8~~; and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

(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 ~~for~~ the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Nodal Day-Ahead Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or 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 and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer 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, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide 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 the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed 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 Energy Offer Floor 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 nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, 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, Demand Response 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 TMNSR 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, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a Resource shall be determined for each Resource that the ISO re-dispatches 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 Location for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve or local TMOR from the Resource's expected output, consumption, or demand reduction 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 linear programming 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 for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour 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.

SECTION III

MARKET RULE 1

APPENDIX F

NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer used in making the decision to commit the Resource, and (2) the Supply Offer used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, and is subject to the following conditions,

i. The Effective Offer used in making the decision to commit the Resource establishes the quantity and price pairs for output up to the Resource's Economic Minimum Limit, the Start-Up Fee, the No-Load Fee, and the operating limits used for NCPC calculations.

ii. In the event the Resource's Economic Minimum Limit is increased after the decision to commit the Resource, the energy price parameter for output at the Economic Minimum Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output up to the increased Economic Minimum Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee or the No-Load Fee that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

b. Treatment of Self-Schedules.

i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the Energy Offer Floor. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. [Reserved.]

d. Supply Offers Applicable When Minimum Run Time Carries Into Second Operating Day. If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Resource Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day.

e. Supply Offers Applicable When Committed Prior to Day-Ahead Energy Market. If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing. Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Lead Fee and Economic Minimum Limit in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit value that take place in the course of the audit.

g. Coordinated External Transactions are Not Eligible for NCPC. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales.

h. Following Dispatch Instructions.

i. Generation Resources with an Economic Maximum Limit less than or equal to 50 MWs are considered to be following a Dispatch Instruction if the actual output of the Resource is not greater than 5 MWs above its Desired Dispatch Point and is not less than 5 MWs below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

Section III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that clears the Day-Ahead Energy Market in an hour are eligible for Day-Ahead Energy Market NCPC Credits for the hour.

III.F.2.1.2. **Settlement Period.** For purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. **Eligible Quantity.** The eligible quantity of energy for a Resource is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.4 **Hourly Cost.** The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to the following conditions.

III.F.2.1.4.1 The Start-Up Fee is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire.

III.F.2.1.4.2 When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.1.5 **Hourly Revenue.** The hourly revenue for a Resource is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

III.F.2.1.6 **Credit Calculation (non-Fast Start Generator or non-Flexible DNE Dispatchable Generator).** The Day-Ahead Energy Market NCPC Credit for a Resource, other than a Fast Start Generator or a Flexible DNE Dispatchable Generator, is equal to the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period.

III.F.2.1.7 Credit Calculation (Fast Start Generator or Flexible DNE Dispatchable Generator). The Day-Ahead Energy Market NCPC Credit for a Fast Start Generator or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2 Real-Time Energy Market NCPC Credits

Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit and a Real-Time Dispatch NCPC Credit.

III.F.2.2.1 Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that has been submitted in the Real-Time Energy Market in an hour are eligible for Real-Time Energy Market NCPC Credits for the hour.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period. For purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is online and operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation. In the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.1. For determining the hourly costs used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the amount of energy equal to the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour.

III.F.2.2.2.2.2 For determining the hourly revenues used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour, except that actual metered output is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the hour, (ii) when the Resource is ramping from an offline state to be released for dispatch and (iii) after the Resource has been released for shutdown.

III.F.2.2.2.3. Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each hour of the settlement period, subject to the following conditions.

III.F.2.2.2.3.1 The energy cost for an hour excludes the cost of energy produced when the Resource is ramping from an offline state to be released for dispatch and energy produced after the Resource has been released for shutdown.

III.F.2.2.2.3.2 The Start-Up Fee is apportioned equally over the hours from the time the Resource is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(a) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Resource is released for dispatch, as measured from the time the Resource was scheduled to be released for dispatch, divided by the time from when the Resource was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(b) The Start-Up Fee is excluded from the hourly costs calculation if the Resource is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Resource's synchronization as a Pool-Scheduled Resource.

(c) The portion of the Start-Up Fee apportioned to any hour during which the Resource is not online because the Resource has tripped is excluded from the hourly cost calculation, except in the event the Resource is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Resource's step-up transformer. It is the responsibility of the Lead Market Participant for the Resource to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(d) The Start-Up Fee is not reduced when the Resource has shutdown with the ISO's approval prior to the end of its Commitment Period.

(e) The additional Start-Up Fee for a Resource requested to re-start following a trip is apportioned equally over the remaining hours of the Commitment Period when the ISO requests a Resource to re-start to complete its Commitment Period.

(f) When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.2.2.3.3. The No-Load Fee is applied to each hour during the period when the Resource is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Resource is released for dispatch, the hour during which the Resource is released for shutdown, and any other hour during which the Resource operates for less than 60 minutes.

III.F.2.2.2.4 **Hourly Revenue.** The hourly revenue for a Resource is equal to the Real-Time Price for each hour of the settlement period multiplied by the eligible quantity. The hourly revenue for an hour is increased by the amount by which the hourly revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the hourly costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3 for that hour. The hourly revenue for an hour is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the hour pursuant to Section III.F.2.3.10. The revenues when the Resource is ramping from an offline state to be released for dispatch are apportioned equally to the hours of the Minimum Run Time.

III.F.2.2.2.4.1. Revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled hour, calculated as the Real-Time Price multiplied by the output, are excluded from the hourly revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.5 Credit Calculation (for non-Fast Start Generators or non-Flexible DNE Dispatchable Generator). The Real-Time Commitment NCPC Credit for a Resource, other than a Fast Start Generator or a Flexible DNE Dispatchable Generator, is equal to:

(a) for the portion of each Commitment Period within a settlement period that contain hours of the Minimum Run Time, the greater of (i) zero, and; (ii) the total hourly cost for the Resource for the period minus the total hourly revenue for the Resource for the period,

plus,

(b) for each remaining hour of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

(i) The maximum potential net revenue is the maximum accumulated net hourly revenue for operating and then shutting down during the period.

(ii) The actual net revenue is the accumulated net hourly revenue over the period.

(iii) The net hourly revenue is the hourly revenues minus hourly costs in each hour of the period.

III.F.2.2.2.6. Credit Calculation (for Fast Start Generators or Flexible DNE Dispatchable Generator). The Real-Time Commitment NCPC Credit for a Fast Start Generator or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2.3. Real-Time Dispatch NCPC Credits

III.F.2.2.3.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an hour when the Desired Dispatch Point and the actual metered output for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when the

Resource is ramping from an offline state to be released for dispatch and after the Resource has been released for shutdown.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1. For determining the hourly costs used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour.

III.F.2.2.3.2.2. For determining the hourly revenues used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's actual metered output for the hour minus the Resource's Economic Dispatch Point for the hour, except that the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour is used as the eligible quantity when the Real-Time Price is below zero for the hour.

III.F.2.2.3.3 Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee or the No-Load Fee.

III.F.2.2.3.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for the hour multiplied by the eligible quantity, plus the portion of regulation opportunity costs attributed to operation in response to Regulation AGC dispatch signals at a level above the Resource's expected economic dispatch level, as specified in Section III.14.8(b)(ii).

III.F.2.2.3.5. Credit Calculation. The Real-Time Dispatch NCPC Credit for a Resource in an hour is equal to the greater of (i) zero and (ii) the hourly cost minus the hourly revenue for the Resource.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the External Transaction amount (MW) pool-scheduled in the Real-Time Energy Market.

(b) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Real-Time scheduled transaction amount in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the offer price for the hour.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the Real-Time Price for the hour.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the bid price for the hour.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability

III.F.2.3.4.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Dispatchable Asset Related Demand Resource are eligible for real-time posturing NCPC credits for the pumping of a Dispatchable Asset Related Demand Resource that has been Postured to increase consumption.

III.F.2.3.4.2. Eligible Quantity. The eligible quantity for a Resource for each hour is the lesser of the Desired Dispatch Point or the Resource's actual metered consumption.

III.F.2.3.4.3. Hourly Bid. The hourly bid is the greater of, for the eligible quantity of the Resource, the Demand Bid for the hour at the time the ISO initiates the Posturing action or the Demand Bid for the hour if revised after the Posturing action is initiated.

III.F.2.3.4.4. Hourly Cost. The hourly cost is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.4.5. Credit Calculation. The real-time posturing NCPC credit for an hour for the pumping of a Postured Dispatchable Asset Related Demand Resource is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource that is dispatched as a Synchronous Condenser are eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. All Market Participants with an Ownership Share in a Pool-Scheduled Resource are eligible for Cancelled Start NCPC Credits if the ISO cancels its commitment of the Pool-Schedule Resource before the Resource is synchronized to the New England Transmission System, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time;

(b) The Resource's Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

(c) The Resource is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or

(d) The Resource fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee reflected in the Effective Offer multiplied by the percentage of the Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time completed is equal to the number of minutes after the start of the Notification Time the Resource was cancelled divided by the Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource that is pool-scheduled in the Day-Ahead Energy Market are eligible for Hourly Shortfall NCPC Credits for an hour if the ISO cancels its commitment of a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator, or does not dispatch a Fast Start Generator or a Flexible DNE Dispatchable Generator for the hour and the Resource is offline and available for operation, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource’s designation changes to or from a Fast Start Generator, or any time a DNE Dispatchable Generator’s operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, Start-Up Fee parameter and No-Load Fee parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(d), the Start-Up Fee, No-Lead Fee and energy at the Economic Minimum Limit are equal to $0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0 and the energy at the requested dispatch level is the Energy Price Floor.

(b) the Day-Ahead Economic Minimum Limit for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) applies, then

(c) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator or a Flexible DNE Dispatchable Generator, is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, the greater of (i) zero and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Limited Energy Resource are eligible for real-time posturing NCPC credits for any Operating Day during which the Resource has been Postured, when a request to minimize the as-bid production costs of the Resource has been submitted. For purposes of calculating real-time posturing NCPC credits, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Resources will be allocated among the Postured Resources sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Resource prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for pumped storage generators, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generators, or (iii) zero for Resources other than pumped storage generators and fuel oil-fired generators.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Resource would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Resource's Economic Minimum Limit, and Economic Maximum Limit.

(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.

(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Resource is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Resource operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from pumping during the Operating Day after the Resource is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Resource is the actual metered output multiplied by the Real-Time Price for all hours in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource, other than a Limited Energy Resource, are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the generating Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost. For purposes of calculating real-time posturing NCPC credits, the offer parameters used to estimate revenue and cost for an hour are:

(a) the higher of the energy price parameter specified in (i) the Supply Offer for the hour at the time the ISO Postures the Resource, or (ii) the Supply Offer for the hour at the start of the hour.

(b) for Resources Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Resource is Postured.

(c) for Resources Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue. The estimated hourly revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Resource would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Resource's Economic Minimum Limit and Economic Maximum Limit.

III.F.2.3.9.5. Estimated Hourly Cost. The estimated hourly cost for a Resource is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(a) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment.

(b) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

For purposes of determining the estimated hourly cost for a Resource, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Resource is the actual metered output multiplied by the Real-Time Price for the hour.

III.F.2.3.9.7. Actual Hourly Cost. The actual hourly cost for a Resource Postured to remain online but reduce output is the energy price parameter of the Supply Offer in place at the start of the hour for the actual metered output, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Resource Postured offline is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a generator, other than a Limited Energy Resource, is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost.

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, all Market Participants with an Ownership Share in a Resource that is committed and able to respond to Dispatch Instructions during the interval are eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation at any time during the hour in which the interval occurs; or if the Resource is a Settlement Only Resource, a Demand Response Resource, or an External Transaction.

III.F.2.3.10.2. Economic Net Revenue. The economic net revenue for the Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities. The optimized feasible energy and reserve quantities are determined consistent with the resource's offer parameters, and are the energy and reserve quantities that maximize the Resource's net Real-Time energy and reserve revenue for the pricing interval taking prices as fixed during the interval and without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue. The actual net revenue for a Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy multiplied by the Real-Time Price, plus the dispatched reserve quantity multiplied by the the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

III.F.2.3.10.4. Credit Calculation. The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue for the interval less its actual net revenue for the pricing interval.

III.F.2.4. Apportionment of NCPC Credits

Each of the Day-Ahead Energy Market NCPC Credits for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator are apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each of the Real-Time Commitment NCPC Credits for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains hours of the Minimum Run Time, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining hours of the settlement period, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the period.

Each of the Hourly Shortfall NCPC Credits for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits for Fast Start Generators,
- Real-Time Commitment NCPC Credits for Fast Start Generators and Flexible DNE Dispatchable Generators,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability,
- Hourly Shortfall NCPC Credits for Fast Start Generators and Flexible DNE Dispatchable Generators, ~~and~~
- Hourly Shortfall NCPC Credits for non-Fast Start Generators and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit, and~~.~~
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, ~~and~~ Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of of Day-Ahead Load Obligations over all Locations (including the Hub),

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only).

(d) The total NCPC cost for resources following Dispatch Instructions while being postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with postured Dispatchable Asset Related Demand Resources (pumps only).

(e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only).

~~(d)~~(f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

~~(e)~~(g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation within a Reliability Region that is eligible for a Real-Time

Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

~~(f)~~(h) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) Any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired

Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.
If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-

Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation

[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

where each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub).

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation.

[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

where each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes.

plus,

(g) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency

Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only), subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II	HQ-Sandy Pond 3512 & 3521	West Central	100% to West Central

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
External Node	Lines	Massachusetts	Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only).

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%}$ $_{\text{(Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month).}}$

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month).}}$

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month).}}$

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

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.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

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.

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. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of "unavailable" for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net 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.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

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 each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (for Capacity Commitment Periods commencing on or after June 1, 2018, Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

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 July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity 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 Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service 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 July 14, 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 Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in the rules filed with the Commission on January 17, 2014, and accepted by the Commission on May 30, 2014.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer 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.

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.

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.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by (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 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 estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving

Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailment is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a)(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, 2018, 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, 2018.

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 Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead 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, 2018, 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 an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end use customers from multiple delivery points that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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 Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

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, 2018.

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 Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and 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 (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points and meets the criteria specified in Section III.1.11.3(e).

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator 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 below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output level to which a Resource would have been dispatched, based on the Resource's Supply Offer and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a 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 (a) for Resources with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and (c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for non-dispatchable Resources the output level at which a Market Participant anticipates its non-dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the set of Supply Offer values that are used for NCPC calculation purposes as specified in Section III.F.1.a.

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

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.

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 Offer Cap is $1,000/MWh.

Energy Offer Floor is negative $150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours 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.

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 Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a 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) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA 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.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; and (iv) has satisfied its Minimum Down Time.

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 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.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

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, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the "Large Generator Interconnection Agreement", the "Small Generator Interconnection Agreement", or the "Elective Transmission Upgrade Interconnection Agreement" pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

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.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means 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 Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System

Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is 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 or a Public Policy Transmission 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, 2018, 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, 2018, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

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. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

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 Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

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 Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit.

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 calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of the first-year non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity 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.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

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-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. "Non-Incumbent Transmission Developer" also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-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.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2018, 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, 2018, 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, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

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.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point(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 Credits are the Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity

Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand 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.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is a Fast Start Generator, a Flexible DNE Dispatchable Generator, or a Dispatchable Asset Related Demand for which the Market Participant’s Offer Data meets the following criteria: (i) Minimum Run Time does not exceed one hour; and (ii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

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 NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(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, 2018, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2018.

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 Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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 Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b)(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 Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.4 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 Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or 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 Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, for Capacity Commitment Periods commencing on or after June 1, 2018, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in $/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

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, 2018, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation 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 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. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable

Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. 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: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

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.

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).

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource’s capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a 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. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of "available," the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer's Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock: (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

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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 (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate 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 (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart 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 Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than $0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

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. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices 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. 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 power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 Adjustment for Rapid Response Pricing Assets.

For any Real-Time pricing interval during which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, the energy offer of that Rapid Response Pricing Asset shall be adjusted as described in this Section III.2.4 for purposes of the price calculations described in Section III.2.5 and Section III.2.7A. For purposes of the adjustment described in this Section III.2.4, if no Start-Up Fee or No-Load Fee is specified in the submitted Offer Data, a value of zero shall be used, and if no Minimum Run Time or minimum consumption time is specified in the submitted Offer Data, or if the submitted Minimum Run Time or minimum consumption time is less than 15 minutes, a duration of 15 minutes shall be used.

(a) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator, its Economic Minimum Limit shall be set to zero; if the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand, its Minimum Consumption Limit shall be set to zero.

(b) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has not satisfied its Minimum Run Time, its energy offer shall be increased by: (i) the Start-Up Fee divided by the product of the Economic Maximum Limit and the Minimum Run Time; and (ii) the No-Load Fee divided by the Economic Maximum Limit.

(c) If the Rapid Response Pricing Asset is a Fast Start Generator or a Flexible DNE Dispatchable Generator that has satisfied its Minimum Run Time, its energy offer shall be increased by the No-Load Fee divided by the Economic Maximum Limit.

(d) If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has not satisfied its minimum consumption time, its energy offer shall be decreased by: (i) the Start-Up Fee divided by the product of the Maximum Consumption Limit and the minimum consumption time; and (ii) the No-Load Fee divided by the Maximum Consumption Limit.

(e) If the Rapid Response Pricing Asset is a Dispatchable Asset Related Demand that has satisfied its minimum consumption time its energy offer shall be decreased by the No-Load Fee divided by the Maximum Consumption Limit.

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids (adjusted as described in Section III.2.4), and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response 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.2.7A(c); and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node.

(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 pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5 shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes.

III.2.6 Calculation of Nodal Day-Ahead Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or 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 and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer 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, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide 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 the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed 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 Energy Offer Floor 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 nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, 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, Demand Response 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 TMNSR 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, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a Resource shall be determined for each Resource that the ISO re-dispatches 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 Location for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve or local TMOR from the Resource's expected output, consumption, or demand reduction 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 linear programming 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 for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour 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.

SECTION III

MARKET RULE 1

APPENDIX F

NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer used in making the decision to commit the Resource, and (2) the Supply Offer used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, and is subject to the following conditions,

i. The Effective Offer used in making the decision to commit the Resource establishes the quantity and price pairs for output up to the Resource's Economic Minimum Limit, the Start-Up Fee, the No-Load Fee, and the operating limits used for NCPC calculations.

ii. In the event the Resource's Economic Minimum Limit is increased after the decision to commit the Resource, the energy price parameter for output at the Economic Minimum Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output up to the increased Economic Minimum Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee or the No-Load Fee that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

b. Treatment of Self-Schedules.

i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the Energy Offer Floor. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. [Reserved.]

d. Supply Offers Applicable When Minimum Run Time Carries Into Second Operating Day. If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Resource Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day.

e. Supply Offers Applicable When Committed Prior to Day-Ahead Energy Market. If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing. Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Lead Fee and Economic Minimum Limit in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit value that take place in the course of the audit.

g. Coordinated External Transactions are Not Eligible for NCPC. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales.

h. Following Dispatch Instructions.

i. Generation Resources with an Economic Maximum Limit less than or equal to 50 MWs are considered to be following a Dispatch Instruction if the actual output of the Resource is not greater than 5 MWs above its Desired Dispatch Point and is not less than 5 MWs below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

ii. DNE Dispatchable Generators are considered to be following Dispatch Instructions if the actual output of the DNE Dispatchable Generator is at or below its Do Not Exceed Dispatch Point.

Section III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that clears the Day-Ahead Energy Market in an hour are eligible for Day-Ahead Energy Market NCPC Credits for the hour.

III.F.2.1.2. **Settlement Period.** For purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.1.3. **Eligible Quantity.** The eligible quantity of energy for a Resource is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.4 **Hourly Cost.** The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to the following conditions.

III.F.2.1.4.1 The Start-Up Fee is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire.

III.F.2.1.4.2 When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.1.5 **Hourly Revenue.** The hourly revenue for a Resource is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

III.F.2.1.6 **Credit Calculation (non-Fast Start Generator or non-Flexible DNE Dispatchable Generator).** The Day-Ahead Energy Market NCPC Credit for a Resource, other than a Fast Start Generator or a Flexible DNE Dispatchable Generator, is equal to the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period.

III.F.2.1.7 Credit Calculation (Fast Start Generator or Flexible DNE Dispatchable Generator). The Day-Ahead Energy Market NCPC Credit for a Fast Start Generator or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2 Real-Time Energy Market NCPC Credits

Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit and a Real-Time Dispatch NCPC Credit.

III.F.2.2.1 Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that has been submitted in the Real-Time Energy Market in an hour are eligible for Real-Time Energy Market NCPC Credits for the hour.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period. For purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is online and operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation. In the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.1. For determining the hourly costs used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the amount of energy equal to the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour.

III.F.2.2.2.2.2 For determining the hourly revenues used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour, except that actual metered output is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the hour, (ii) when the Resource is ramping from an offline state to be released for dispatch and (iii) after the Resource has been released for shutdown.

III.F.2.2.2.3. Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each hour of the settlement period, subject to the following conditions.

III.F.2.2.2.3.1 The energy cost for an hour excludes the cost of energy produced when the Resource is ramping from an offline state to be released for dispatch and energy produced after the Resource has been released for shutdown.

III.F.2.2.2.3.2 The Start-Up Fee is apportioned equally over the hours from the time the Resource is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(a) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Resource is released for dispatch, as measured from the time the Resource was scheduled to be released for dispatch, divided by the time from when the Resource was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(b) The Start-Up Fee is excluded from the hourly costs calculation if the Resource is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Resource's synchronization as a Pool-Scheduled Resource.

(c) The portion of the Start-Up Fee apportioned to any hour during which the Resource is not online because the Resource has tripped is excluded from the hourly cost calculation, except in the event the Resource is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Resource's step-up transformer. It is the responsibility of the Lead Market Participant for the Resource to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(d) The Start-Up Fee is not reduced when the Resource has shutdown with the ISO's approval prior to the end of its Commitment Period.

(e) The additional Start-Up Fee for a Resource requested to re-start following a trip is apportioned equally over the remaining hours of the Commitment Period when the ISO requests a Resource to re-start to complete its Commitment Period.

(f) When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.2.2.3.3. The No-Load Fee is applied to each hour during the period when the Resource is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Resource is released for dispatch, the hour during which the Resource is released for shutdown, and any other hour during which the Resource operates for less than 60 minutes.

III.F.2.2.2.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for each hour of the settlement period multiplied by the eligible quantity. The hourly revenue for an hour is increased by the amount by which the hourly revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the hourly costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3 for that hour. The hourly revenue for an hour is increased by any Rapid Response Pricing Opportunity Cost NCPC Credits calculated during the hour pursuant to Section III.F.2.3.10. The revenues when the Resource is ramping from an offline state to be released for dispatch are apportioned equally to the hours of the Minimum Run Time.

III.F.2.2.2.4.1. Revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled hour, calculated as the Real-Time Price multiplied by the output, are excluded from the hourly revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.5 Credit Calculation (for non-Fast Start Generators or non-Flexible DNE Dispatchable Generator). The Real-Time Commitment NCPC Credit for a Resource, other than a Fast Start Generator or a Flexible DNE Dispatchable Generator, is equal to:

(a) for the portion of each Commitment Period within a settlement period that contain hours of the Minimum Run Time, the greater of (i) zero, and; (ii) the total hourly cost for the Resource for the period minus the total hourly revenue for the Resource for the period,

plus,

(b) for each remaining hour of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

(i) The maximum potential net revenue is the maximum accumulated net hourly revenue for operating and then shutting down during the period.

(ii) The actual net revenue is the accumulated net hourly revenue over the period.

(iii) The net hourly revenue is the hourly revenues minus hourly costs in each hour of the period.

III.F.2.2.2.6. Credit Calculation (for Fast Start Generators or Flexible DNE Dispatchable Generator). The Real-Time Commitment NCPC Credit for a Fast Start Generator or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2.3. Real-Time Dispatch NCPC Credits

III.F.2.2.3.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an hour when the Desired Dispatch Point and the actual metered output for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when the

Resource is ramping from an offline state to be released for dispatch and after the Resource has been released for shutdown.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1. For determining the hourly costs used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour.

III.F.2.2.3.2.2. For determining the hourly revenues used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's actual metered output for the hour minus the Resource's Economic Dispatch Point for the hour, except that the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour is used as the eligible quantity when the Real-Time Price is below zero for the hour.

III.F.2.2.3.3 Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee or the No-Load Fee.

III.F.2.2.3.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for the hour multiplied by the eligible quantity, plus the portion of regulation opportunity costs attributed to operation in response to Regulation AGC dispatch signals at a level above the Resource's expected economic dispatch level, as specified in Section III.14.8(b)(ii).

III.F.2.2.3.5. Credit Calculation. The Real-Time Dispatch NCPC Credit for a Resource in an hour is equal to the greater of (i) zero and (ii) the hourly cost minus the hourly revenue for the Resource.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the External Transaction amount (MW) pool-scheduled in the Real-Time Energy Market.

(b) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Real-Time scheduled transaction amount in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the offer price for the hour.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the Real-Time Price for the hour.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the bid price for the hour.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability

III.F.2.3.4.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Dispatchable Asset Related Demand Resource are eligible for real-time posturing NCPC credits for the pumping of a Dispatchable Asset Related Demand Resource that has been Postured to increase consumption.

III.F.2.3.4.2. Eligible Quantity. The eligible quantity for a Resource for each hour is the lesser of the Desired Dispatch Point or the Resource's actual metered consumption.

III.F.2.3.4.3. Hourly Bid. The hourly bid is the greater of, for the eligible quantity of the Resource, the Demand Bid for the hour at the time the ISO initiates the Posturing action or the Demand Bid for the hour if revised after the Posturing action is initiated.

III.F.2.3.4.4. Hourly Cost. The hourly cost is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.4.5. Credit Calculation. The real-time posturing NCPC credit for an hour for the pumping of a Postured Dispatchable Asset Related Demand Resource is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource that is dispatched as a Synchronous Condenser are eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. All Market Participants with an Ownership Share in a Pool-Scheduled Resource are eligible for Cancelled Start NCPC Credits if the ISO cancels its commitment of the Pool-Schedule Resource before the Resource is synchronized to the New England Transmission System, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time;

(b) The Resource's Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;

(c) The Resource is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or

(d) The Resource fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee reflected in the Effective Offer multiplied by the percentage of the Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time completed is equal to the number of minutes after the start of the Notification Time the Resource was cancelled divided by the Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource that is pool-scheduled in the Day-Ahead Energy Market are eligible for Hourly Shortfall NCPC Credits for an hour if the ISO cancels its commitment of a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator, or does not dispatch a Fast Start Generator or a Flexible DNE Dispatchable Generator for the hour and the Resource is offline and available for operation, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource that is not a DNE Dispatchable Generator.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator, or any time a DNE Dispatchable Generator's operating characteristics change to or from a Flexible DNE Dispatchable Generator, and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator or a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter, Start-Up Fee parameter and No-Load Fee parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(d), the Start-Up Fee, No-Lead Fee and energy at the Economic Minimum Limit are equal to \$0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to \$0 and the energy at the requested dispatch level is the Energy Price Floor.

(b) the Day-Ahead Economic Minimum Limit for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator in the event the total of the energy price parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit for an hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) applies, then

(c) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators and non-Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator or a Flexible DNE Dispatchable Generator, is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, the greater of (i) zero and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators and Flexible DNE Dispatchable Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator or a Flexible DNE Dispatchable Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Limited Energy Resource are eligible for real-time posturing NCPC credits for any Operating Day during which the Resource has been Postured, when a request to minimize the as-bid production costs of the Resource has been submitted. For purposes of calculating real-time posturing NCPC credits, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Resources will be allocated among the Postured Resources sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Resource prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for pumped storage generators, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generators, or (iii) zero for Resources other than pumped storage generators and fuel oil-fired generators.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy output is estimated for each hour by allocating the Postured energy to hours that the Resource would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Resource's Economic Minimum Limit, and Economic Maximum Limit.

(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.

(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Resource is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Resource operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from pumping during the Operating Day after the Resource is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. **Actual Revenue.** The actual revenue for a Resource is the actual metered output multiplied by the Real-Time Price for all hours in the settlement period.

III.F.2.3.8.8. **Actual Avoided Replacement Cost.** The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. **Credit Calculation.** The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. **Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability**

III.F.2.3.9.1. **Eligibility for Credit.** All Market Participants with an Ownership Share in a generating Resource, other than a Limited Energy Resource, are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. **Settlement Period.** For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the generating Resource is Postured.

III.F.2.3.9.3. **Offer Used for Estimated Hourly Revenue and Cost.** For purposes of calculating real-time posturing NCPC credits, the offer parameters used to estimate revenue and cost for an hour are:

(a) the higher of the energy price parameter specified in (i) the Supply Offer for the hour at the time the ISO Postures the Resource, or (ii) the Supply Offer for the hour at the start of the hour.

(b) for Resources Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Resource is Postured.

(c) for Resources Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue. The estimated hourly revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Resource would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Resource's Economic Minimum Limit and Economic Maximum Limit.

III.F.2.3.9.5. Estimated Hourly Cost. The estimated hourly cost for a Resource is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(a) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment.

(b) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

For purposes of determining the estimated hourly cost for a Resource, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Resource is the actual metered output multiplied by the Real-Time Price for the hour.

III.F.2.3.9.7. Actual Hourly Cost. The actual hourly cost for a Resource Postured to remain online but reduce output is the energy price parameter of the Supply Offer in place at the start of the hour for the actual metered output, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Resource Postured offline is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a generator, other than a Limited Energy Resource, is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost.

III.F.2.3.10. Rapid Response Pricing Opportunity Cost NCPC Credits Resulting from Commitment of Rapid Response Pricing Assets

III.F.2.3.10.1. Eligibility for Credit. During any five-minute pricing interval in which a Rapid Response Pricing Asset is committed by the ISO and not Self-Scheduled, all Market Participants with an Ownership Share in a Resource that is committed and able to respond to Dispatch Instructions during the interval are eligible to receive a Rapid Response Pricing Opportunity Cost NCPC Credit; provided, however, that such credit shall be zero if the Resource is non-dispatchable; the Resource has been Postured or has provided Regulation at any time during the hour in which the interval occurs; or if the Resource is a Settlement Only Resource, a Demand Response Resource, or an External Transaction.

III.F.2.3.10.2. Economic Net Revenue. The economic net revenue for the Resource during the pricing interval is the Resource's optimized feasible energy quantity multiplied by the Real-Time Price, plus the optimized feasible reserve quantity multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities. The optimized feasible energy and reserve quantities are determined consistent with the resource's offer parameters, and are the energy and reserve quantities that maximize the Resource's net Real-Time energy and reserve revenue for the pricing interval taking prices as fixed during the interval and without changing the Resource's commitment status.

III.F.2.3.10.3. Actual Net Revenue. The actual net revenue for a Resource is the greater of: (i) the actual energy quantity supplied during the pricing interval multiplied by the Real-Time Price, plus the actual reserve quantity supplied during the pricing interval multiplied by the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities; and (ii) the dispatched energy multiplied by the Real-Time Price, plus the dispatched reserve quantity multiplied by the the Real-Time Reserve Clearing Price, minus the offered energy cost for those quantities.

III.F.2.3.10.4. Credit Calculation. The real-time Rapid Response Pricing Opportunity Cost NCPC Credit for a Resource is equal to the greater of: (i) zero; and (ii) the Resource's economic net revenue for the interval less its actual net revenue for the pricing interval.

III.F.2.4. Apportionment of NCPC Credits

Each of the Day-Ahead Energy Market NCPC Credits for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator are apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each of the Real-Time Commitment NCPC Credits for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains hours of the Minimum Run Time, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii) for all remaining hours of the settlement period, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the period.

Each of the Hourly Shortfall NCPC Credits for a non-Fast Start Generator or a DNE Dispatchable Generator that is not a Flexible DNE Dispatchable Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period.

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits for Fast Start Generators,
- Real-Time Commitment NCPC Credits for Fast Start Generators and Flexible DNE Dispatchable Generators,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability,
- Hourly Shortfall NCPC Credits for Fast Start Generators and Flexible DNE Dispatchable Generators,
- Hourly Shortfall NCPC Credits for non-Fast Start Generators and DNE Dispatchable Generators that are not Flexible DNE Dispatchable Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit, and
- Rapid Response Pricing Opportunity Cost NCPC Credits as described in Section III.F.2.3.10.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, and Rapid Response Pricing Opportunity Cost NCPC Credit is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of of Day-Ahead Load Obligations over all Locations (including the Hub),

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject to the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only).

(d) The total NCPC cost for resources following Dispatch Instructions while being postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with postured Dispatchable Asset Related Demand Resources (pumps only).

(e) The total NCPC cost for Rapid Response Pricing Opportunity Cost NCPC Credit during pricing intervals in which one or more Rapid Response Pricing Asset is committed in the Real-Time Energy Market (and not Self-Scheduled) is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only).

(f) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(g) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation within a Reliability Region that is eligible for a Real-Time

Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

(h) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) Any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired

Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.
If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-

Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation

[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],

where each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub).

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation.

[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],

where each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes.

plus,

(g) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency

Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only), subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II	HQ-Sandy Pond 3512 & 3521	West Central	100% to West Central

External Node Common Name	**Associated Transmission Facilities**	**Reliability Region(s)**	**Allocator**
External Node	Lines	Massachusetts	Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only).

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ > .06 X Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%}$ $_{\text{(Reliability Region)}}$

Where:

Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$.

Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region, month)}}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{\text{(Reliability Region)}}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ to be reallocated = Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$ X Min (Condition 1 Rate $_{\text{(Reliability Region, month)}}$, Condition 2 Rate $_{\text{(Reliability Region, month)}}$)

Where:

Condition 1 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus .06 times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

Condition 2 Rate $_{\text{(Reliability Region, month)}}$ equals the Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\text{\% (Reliability Region)}}$ times the Load Weighted Real-Time LMP $_{\text{(Reliability Region, month)}}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{\text{(Reliability Region, month)}}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ / Real-Time Load Obligation $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Real-Time Load Obligation $_{\text{(Participant, Reliability Region, month)}}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{\text{(Transmission Customer, Reliability Region, month)}}$ / Regional Network Load $_{\text{(Reliability Region, month)}}$) * Local Second Contingency Protection Resource Charges $_{\text{(Reliability Region, month)}}$ to be reallocated

Where:

Regional Network Load $_{\text{(Reliability Region, month)}}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{\text{(Customer, Reliability Region, month)}}$ equals:
The Transmission Customer’s monthly MWh of Regional Network Load in the Reliability Region.

Attachment A

memo

To: NEPOOL Markets Committee

From: Market Development and Business Architecture & Technology

Date: March 4, 2015

Subject: Fast-Start Pricing Improvements – Revised Edition

This memorandum discusses the ISO's proposed changes to the real-time market's pricing procedures when fast-start resources are committed and dispatched. It summarizes the problems the ISO seeks to address, and how the ISO's proposed changes can address these problems. This memorandum also provides several numerical examples to help explain how the proposed new pricing logic works, and to illustrate the differences from current pricing outcomes.

This revised edition incorporates and supersedes the contents of the memorandum on this topic provided to the Markets Committee on February 6th, 2015. This revised version provides additional numerical examples and expanded explanation of opportunity cost treatment under the ISO's proposed fast-start pricing improvements.

The ISO anticipates discussing these problems and the proposed solutions with stakeholders over the next several months. We welcome additional questions and feedback on these issues.

Context and Problem Summary

The ISO currently employs a special pricing method in the real-time energy market when fast-start resources are committed and dispatched.[1] This pricing method was developed more than a decade ago, and reflects significant software limitations that existed at the time. Those software limitations no longer exist, given technological advances in recent years, making it appropriate to consider potential improvements to the ISO's fast-start pricing methods.

In its 2012 and 2013 Market Assessments, the ISO's External Market Monitor, Potomac Economics, expressed concerns with the current fast-start resource pricing method. Specifically, it observed that

> Fast-start generators are routinely deployed economically, but the resulting costs are often not fully reflected in real-time prices. In 2013, 60 percent of the fast-start capacity that was started in the real-time market did not recoup its offer. This leads fast-start resources with flexible characteristics to be substantially

[1] Fast-start resources are units that can deliver energy from an off-line status within 30 minutes. Additional requirements of fast-start resources are provided in the ISO Tariff, §I.2.2.

> under-valued in the real-time market, despite the fact that they provide significant economic and reliability benefits.[2]

Potomac Economics recommended that "the ISO evaluate potential changes in the pricing methodology that would allow the deployment costs of fast-start generators to be more fully reflected in the real-time market prices."[3]

In addition, the ISO is concerned with a second, distinct shortcoming of the current fast-start dispatch and pricing process. Currently, when a fast-start generator is committed during real-time operations, the special fast-start pricing logic may yield a dispatch solution with (generally small) over-generation system-wide. This over-generation is absorbed by the automatic regulation-down response of resources providing frequency regulation service, which maintains the system's power balance. However, from an economic perspective, this is often not a least-cost outcome; it would typically be more efficient if the dispatch solution did not produce an over-generation result when fast-start resources are initially committed, thereby avoiding the need for additional regulation-down service.

In summary, there are two central problems the ISO seeks to address through improvements to real-time fast-start pricing:

1. Fast-start resources typically cannot set the energy market price under the current fast-start pricing method, even when they are economically committed and dispatched in real-time. As a result, the costs of deploying fast-start resources are not reflected in real-time energy and reserve prices even when deployed efficiently to meet energy demand.

2. The current fast-start dispatch and pricing method can produce inefficient outcomes during the initial startup phase for the fast-start unit. The inefficiency results in a need for additional service from generators providing frequency regulation at the time, potentially at greater cost than would occur with an efficient fast-start dispatch and pricing method.

In the fall of 2014, the ISO discussed these and related fast-start pricing issues in its Real-Time Pricing Technical Seminar Series. Additional information from the seminar series that discusses these two problems in detail is available in the Training Materials section of the ISO web site, at http://www.iso-ne.com/participate/training/materials.[4]

Overview of Proposed Fast-Start Pricing Changes

To address these problems, the ISO proposes several simple modifications to the existing real-time dispatch and pricing process when fast-start resources are committed and dispatched. In general, these modifications will enable an ISO-committed fast-start resource to set the real-time locational marginal price (LMP) when its dispatch is "economically useful" for meeting the system's co-optimized real-time energy and reserve requirements. In this context, the term

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[2] Potomac Economics, *2013 Assessment of the ISO New England Electricity Markets*, p. 22, available at http://www.iso-ne.com/markets-operations/market-monitoring-mitigation/external-monitor.

[3] *Ibid.*

[4] See especially the Session #6 discussion of fast-start pricing, at http://www.iso-ne.com/static-assets/documents/2014/09/price_information_technical_session6.pdf

"economically useful" means the power system's total production costs would be greater without the fast-start unit's output.

The modifications entail four closely-related changes to dispatch, pricing, and compensation when fast-start units are deployed. In summary, they are:

1. **Dispatch respects offered unit parameters.** The real-time commitment and dispatch process will respect the offered "economic minimum" (EcoMin) output level of each committed fast-start resource. This treatment differs slightly from current practice during the startup-phase of a fast-start unit's dispatch, as explained in detail further below.

   This treatment will resolve the potential inefficiencies associated with relying on automatic frequency regulation-down service to counterbalance potential over-generation instructions in the dispatch interval(s) in which fast-start units are initially committed.

2. **Pricing 'relaxes' minimum output levels for committed fast-starts.** For committed fast-start units, the calculation of LMPs and reserve market clearing prices (RMCPs) in the ISO's real-time pricing algorithm will treat the unit's minimum output level as zero (this is also known as 'relaxing the EcoMin' to zero). This differs from current practice, which treats a fast-start unit's minimum output level as zero only during the unit's initial commitment (startup) phase.

   Relaxing the minimum output level to zero after the initial commitment (startup) phase will enable the ISO's pricing algorithm to treat a committed fast-start unit as marginal, and therefore potentially able to set price, under a broader range of dispatch conditions than the current pricing method. As explained further below, these conditions correspond, in a precise way, to the aforementioned concept of a unit being "economically useful" for meeting the system's co-optimized real-time energy and reserve requirements.

3. **Revisions to the treatment of fast-start units' commitment costs.** Presently, the ISO real-time pricing method incorporates the Start-Up and No-Load Fees of a fast-start resource into its incremental energy offer price, but only during the initial commitment (startup) phase of the unit's operation. The ISO proposes to extend this treatment throughout the unit's Minimum Run Time for Start-Up Fee and throughout the unit's actual run time for No-Load Fee.

   To accomplish this, minor modifications to the formulas for incorporating these commitment costs into fast-start incremental energy offers in the pricing method are necessary. These are explained in further detail below.

4. **Compensation for lost-opportunity (posturing) costs.** When fast-start units are deployed, one (or possibly several) other online generators may need to be "postured down" to ensure the dispatch satisfies power balance (that is, to avoid the over-generation problem described previously). In certain situations, the committed fast-start unit may set the LMP at a value higher than the energy price offer(s) of the unit(s) that are postured down in the economic dispatch solution. If this occurs, the unit(s) postured down incur a lost-opportunity cost from following their dispatch instruction while facing a rising price.

   To ensure that resources postured down under these conditions retain proper economic incentives to follow the ISO's dispatch instruction, the ISO proposes to compensate online generators 'held down' in these specific circumstances for their lost opportunity cost. At a conceptual level, this is consistent with the ISO's current practice of providing posturing credits in other contexts. For example, this already occurs when a resource's real-time energy output is 'held down' against price in order to ensure future real-time operating reserves are available.

Comparing the current and proposed FS pricing

The following table summarizes the differences between the ISO's current and proposed real-time pricing methods when fast-start units are committed and dispatched.

<table>
<tr><th colspan="5">Table 1 - Summary of Current And Proposed Fast-Start Resource Treatment.</th></tr>
<tr><th rowspan="2">Time Period</th><th colspan="2">Current (Dispatch and Pricing)</th><th colspan="2">Proposed</th></tr>
<tr><td>During First Commitment (startup) Interval</td><td>After First Commitment (startup) Interval</td><td>During the Minimum Run Time (MRT)</td><td>After the Minimum Run Time (MRT)</td></tr>
<tr><td>Applicable Resources</td><td>10/30-min FS Resources</td><td>-</td><td colspan="2">10/30-min FS Resources and DARDs</td></tr>
<tr><td>Treatment of FS Minimum Output (EcoMin) Value</td><td>Dispatch and pricing solutions relax minimum to 0 MW</td><td>Dispatch and pricing solutions respect offered minimum MW</td><td colspan="2">Dispatch solution respects offered minimum; Pricing solution relaxes minimum to 0 MW</td></tr>
<tr><td>Treatment of Start-Up and No-load Fees</td><td>SU amortized over EcoMax and 1hr.; NL amortized over EcoMax; both included in pricing</td><td>Not Included in Pricing</td><td>SU amortized over EcoMax and MRT; NL amortized over EcoMax; both included in pricing</td><td>NL amortized over EcoMax, included in pricing</td></tr>
<tr><td>Lost Opportunity Cost (LOC)</td><td colspan="2">Does not arise (see text)</td><td colspan="2">Credit for LOC incurred by following dispatch when a FS unit sets price</td></tr>
</table>

Illustrative Numerical Examples

To illustrate the ISO's proposed fast-start pricing modifications, it is useful to consider two numerical examples. These examples compare current practice with the proposed changes.

Example 1

Assume there are two generating units, one a fast-start (FS) unit and the other not a fast start (Non-FS) unit. Assume each unit has the attributes shown in the following table.

Table 2 - Offer Parameters for Example 1

	FS unit		Non-FS unit	
EcoMin (MW)	50		100	
EcoMax (MW)	50		500	
Incremental Energy Offer Price ($/MWh)	$30	50 MW	$20 $60	100 to 400 MW 400 to 500 MW

We will also assume:

- Energy demand is 430 MW.
- The FS unit is initially off-line. It has a Start-Up Fee of $150 per start, a No-Load Fee of $100 per hour, and a Minimum Run Time (MRT) of ½ hour.
- The non-FS unit is online.
- For simplicity, no transmission constraints, reserve requirements, or energy losses are considered.
- The analysis period is one hour.

Current Practice

For comparison purposes, we first explain how fast-start pricing currently works using Example 1. Under the current FS pricing method, pricing and dispatch are handled differently during the initial commitment (startup) phase and during subsequent operating intervals. We explain each in turn.

Current Practice: First Commitment (Startup) Interval

Under current practice, two modifications are made to a resource's offer parameters for the initial commitment (startup) phase: The amortized Start-Up and No-Load Fees are added to the resource's incremental energy price, and the offered EcoMin value is treated as 0 MW.

Commitment Cost Treatment. The current FS pricing and dispatch logic uses an *adjusted incremental energy offer price* that incorporates the FS resource's amortized Start-Up and No-Load Fees. The adjusted incremental energy offer price the sum of three elements:

Incremental Energy Offer Price + Amortized Start-Up Fee + Amortized No-Load Fee

where the Start-Up Fee is currently amortized (that is, "averaged") over the unit's Economic Maximum output and one hour:

Amortized Start-Up Fee = Start-Up Fee / (EcoMax MW × 1 hour)

and where the No-Load Fee is currently amortized over the unit's EcoMax:

Amortized No-Load Fee = No-Load Fee / EcoMax MW

In Example 1, the FS unit's Incremental Energy Offer Price is $30 per MWh, and the Adjusted Incremental Energy Offer Price is calculated as follows:

$30/MWh energy + $150 startup / (50 MW × 1 hour) + $100 no-load per hr. / 50 MW

which evaluates as:

$30/MWh   + $3/MWh   + $2/MWh

This yields an adjusted incremental energy offer price of **$35/MWh** applicable for the initial commitment (startup) interval.

EcoMin Value Treatment. In addition, the EcoMin of the FS unit is "relaxed" to zero in the pricing and dispatch software in the initial commitment (startup) interval. This treats the FS unit as if it is fully dispatchable between 0 MW and its EcoMax (50 MW) in the security constrained economic dispatch and pricing solutions.

Summary. The new table of the modified "characteristics" of the FS unit that is used in the current pricing and dispatch system for the initial commitment (startup) interval is shown in the table below. The characteristics of the non-FS unit are unchanged.

Table 3 - Modified Offer Parameters Under Current Practice, First Commitment Interval

	FS unit		non-FS unit	
EcoMin (MW)	~~50~~ 0		100	
EcoMax (MW)	50		500	
Adjusted Incremental Energy Offer price ($/MWh) and applicable dispatch range (MW)	~~30~~ $35	~~50~~ 0 to 50 MW range	$20	100 to 400 MW
			$60	400 to 500 MW

Current Practice: Dispatch and Pricing Outcomes in the First Commitment Interval

The current FS pricing and dispatch method uses the revised FS unit parameters above in the first commitment interval. For these parameters, the least-cost dispatch and pricing solution for Example 1 is:

- Non-FS unit dispatch = 400 MW
- FS unit dispatch = 30 MW
- LMP = $35/MWh, set by FS unit's adjusted incremental energy offer price.

This uses the least-expensive MW first, which are the 400 MW from the non-FS unit offered at $20/MWh. Then the next expensive MW, which is from the FS unit at the $35 adjusted incremental energy offer price. Since this is sufficient to meet the 430 MW of energy demand, the upper block of the non-FS unit is not dispatched and the dispatch would satisfy the *next* MW of energy demand (if, say, demand increases to 431 MW) using the FS unit at an adjusted incremental energy offer price of $35, the FS unit sets the LMP at $35/MWh.

The Over-Generation Instruction Issue. The ISO will send out a desired dispatch point (DDP) signal to the non-FS unit of 400 MW, corresponding to its least-cost dispatch. However, it will <u>not</u> send out a 30 MW instruction to the FS unit. To avoid sending dispatch points that are an infeasible operating instruction to the units, the ISO currently 'rounds up' the DDP sent to any FS unit to its <u>offered</u> EcoMin value. This means, in this situation, the FS unit will be electronically sent an actual DDP of 50 MW, not the 30 MW value obtained in the economic dispatch solution.

Note what happens as a result: Total dispatched output is 400 MW + 50 MW = 450 MW, to meet energy demand of only 430 MW. This means that, in the absence of other factors to counterbalance the over-generation instructions, the system would have 20 MW of excess generation. In practice, the excess generation is absorbed by the automatic regulation-down from (other) units on frequency regulation service. This is inefficient, in general, as units providing regulation service can be expected to have a lower marginal cost (esp. in the downward direction) than the unit that would receive the lower DDP in an energy-balanced dispatch (the non-FS unit in the example above).

Current Practice: Dispatch and Pricing Outcomes <u>After</u> the First Commitment Interval

Commitment Cost Treatment. Under the current FS pricing method, a FS unit's commitment costs are treated differently before and after the unit's first commitment (startup) interval. Specifically, they are ignored. Pricing is based on the incremental energy offer price, and does not include any amortized Start-Up or No-Load Fees.

EcoMin Value Treatment. There is another important difference between before and after the first commitment (startup) interval of the FS unit. In the dispatch and pricing calculations, after its first commitment interval, the FS unit's <u>offered</u> EcoMin value is used. It is not 'relaxed' to zero, as occurs in the *first* commitment interval above.

Summary. For Example 1, the pricing and dispatch solutions after the first commitment interval are calculated using the parameters summarized in the table below.

<table>
<tr><th colspan="5">Table 4 - Offer Parameters Under Current Practice, After First Commitment Interval</th></tr>
<tr><td></td><td colspan="2">FS unit</td><td colspan="2">non-FS unit</td></tr>
<tr><td>EcoMin (MW)</td><td colspan="2">50</td><td colspan="2">100</td></tr>
<tr><td>EcoMax (MW)</td><td colspan="2">50</td><td colspan="2">500</td></tr>
<tr><td rowspan="2">Incremental Energy Offer Price ($/MWh)</td><td rowspan="2">$30</td><td rowspan="2">50 MW</td><td>$20</td><td>100 to 400 MW</td></tr>
<tr><td>$60</td><td>400 to 500 MW</td></tr>
</table>

For these parameters, the least-cost dispatch solution for Example 1 is:

- Non-FS unit dispatch = 380 MW
- FS unit dispatch = 50 MW
- LMP = $20/MWh, set by the non-FS unit's energy offer price.

The FS unit is block-loaded at 50MW, since its EcoMin of 50 MW is respected in the dispatch. The remaining 380 MW of demand is satisfied by the non-FS unit.

If demand increases by 1MW, to 431MW, the output of the block-loaded FS unit would remain unchanged at 50 MW, and the next MW of energy demand would be met by the non-FS unit at its incremental energy offer price of $20 per MWh. Hence, after the first commitment interval of the FS unit, the LMP is set by the non-FS unit at $20 per MWh.

Fast Start Unit's Net Revenue and Make-Whole Payments

Note that prices differ in the first interval and subsequent intervals. The initial commitment (startup) interval has a duration of 5 minutes, which is 1/12 hours. Assuming the FS unit follows its dispatch instruction, its revenue during the first interval when the price is $35 per MWh is:

$$50 \text{ MW} \times \$35/\text{MWh} \times (1/12 \text{ h}) = \$145.83$$

The remainder of the hour, the LMP is $20 per MWh. This applies for the subsequent 55 minutes, or 11/12 hours, providing revenue of:

$$50 \text{ MW} \times \$20/\text{MWh} \times (11/12 \text{ h}) = \$916.67.$$

For the hour, the FS unit's total costs are:

$$\textit{Costs} = 50 \text{ MW} \times \$30/\text{MWh } \textit{energy} + \$150 \textit{ startup} + \$100 \textit{ no-load} = \$1{,}750.$$

The FS unit's net revenue for the hour are its total revenue minus total costs, or

Net revenue = \$145.83 + \$916.67 – \$1750 = **– \$687.50**

The FS unit has a net loss of \$687.50 for the hour. To break even, the FS unit requires a make-whole payment (MWP) of \$687.50, as provided for under current NCPC rules.

Proposed New Fast Start Pricing Method

Under the proposed new FS pricing method, the ISO will use the same dispatch logic and method in both the initial commitment (startup) phase and during subsequent operating intervals. However, in pricing, there is a slight difference in the treatment of the resource's commitment costs before and after the unit's Minimum Run Time (MRT). We therefore explain the proposed new treatment first for intervals before the fast-start unit's MRT is complete, and then for intervals after the MRT.

Proposed Practice: During MRT

Commitment Cost Treatment. The proposed new treatment will also base pricing on an *adjusted incremental energy offer price* that incorporates the FS resource's Start-Up and No-Load Fees. Like today, the adjusted incremental energy offer price is the sum of three elements:

Incremental Energy Offer Price + Amortized Start-Up Fee + Amortized No-Load Fee

Under the new treatment, the Start-Up Fee will be amortized (that is, "averaged") over the unit's Economic Maximum output and its Minimum Run Time:

*Amortized Start-Up Fee = Start-Up Fee / (EcoMax MW × **MRT**)*

The only difference from current practice in this amortization formula far is the use of the FS unit's actual MRT (proposed treatment), instead of a fixed 1 hour value (current treatment).[5]

Like current practice, the No-Load Fee will remain amortized over the unit's EcoMax:

Amortized No-Load Fee = No-Load Fee / EcoMax MW

In Example 1, the FS unit's Incremental Energy Offer Price is \$30 per MWh, and it was assumed to have a 30 minute MRT value. Thus, the Adjusted Incremental Energy Offer Price under the proposed new treatment would be:

\$30/MWh *energy* + \$150 *startup* / (50 MW × **0.5 hour MRT**) + \$100 *no-load* per hr. / 50 MW

which evaluates as:

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[5] Conceivably, a unit could offer a MRT of zero. Because the ISO's software systems (when the proposed treatment is implemented) are designed to make FS commitment and de-commitment decisions at 15 minute intervals under normal operating conditions, the ISO will amortize a FS unit's Start-Up Fee over 15 minutes (0.25 hours) in the event a FS unit specifies a MRT of *less* than 15 minutes. In formulas, this means the amortized Start-Up fee is determined as:

$$\textit{Startup Fee} / (\textit{EcoMax}\ \mathrm{MW} \times \max\{\ 0.25\ \textit{hr},\ \textit{MRT}_{\textit{offered}}\ \})$$

$30/MWh + $6/MWh + $2/MWh

This yields an adjusted incremental energy offer price of **$38/MWh.** This adjusted incremental energy offer price is applicable for the duration of the units MRT.

EcoMin Value Treatment. Under the proposed new treatment, the EcoMin of the FS unit is treated differently in the dispatch and in the pricing calculations:

- The dispatch solution is calculated treating the FS unit's EcoMin value as offered. In Example 1, the offered EcoMin is 50 MW.
- The pricing solution is calculated treating ("relaxing") the EcoMin value of the FS unit as zero. This treats the FS unit as if it has a broader dispatchable range, from 0 MW to its EcoMax (50 MW), in the pricing process.

Summary. The new table of the modified "characteristics" used in the proposed pricing method for intervals during the FS unit's MRT is shown below. The characteristics of the non-FS unit are unchanged. Note that unlike the current FS pricing method, under the ISO's proposed FS pricing treatment, there is no difference between the first and subsequent commitment intervals of the FS unit, *per se.*

Table 5 - Modified Offer Parameters Under Proposed Pricing Treatment, During MRT				
	FS unit		Non-FS unit	
EcoMin (MW)	~~50~~ 0		100	
EcoMax (MW)	50		500	
Adjusted Incremental Energy Offer Price ($/MWh)	~~30~~ $38	~~50~~ 0 to 50 MW	$20	100 to 400 MW
			$60	400 to 500 MW

Proposed Practice: Dispatch and Pricing Outcomes During the MRT

Under the proposed new FS treatment, the dispatched MW for each unit are calculated, in least-cost manner, using the resource's offered EcoMin and offer cost parameters. These are shown in prior Table 2. As discussed following Table 4, the least cost dispatch solution is:

- Non-FS unit dispatch = 380 MW
- FS unit dispatch = 50 MW

The FS unit is block-loaded at 50MW, since its EcoMin of 50 MW is respected in the dispatch. The remaining 380 MW of demand is satisfied by the non-FS unit.

Pricing. Under the proposed new FS treatment, the price is calculated using the FS unit's Adjusted Incremental Energy Offer and 'relaxed' EcoMin value. These are shown in Table 5. With these modified parameters, the pricing run would minimize total costs with pricing run quantities of: [6]

- Pricing run quantity for the Non-FS unit = 400 MW
- Pricing run quantity for the FS unit = 30 MW
- LMP = **$38/MWh**, set by FS unit's adjusted offer price.

This pricing solution uses the least-expensive MW first, which are the 400 MW from the non-FS unit offered at $20/MWh. Then the next expensive MW, which is from the FS unit at the $38/MWh adjusted offer price.

In the pricing run calculation, to satisfy the *next* MW of energy demand (if, say, demand increases by 1 MW, from 430 MW to 431 MW), the pricing process would meet demand at least-cost using an incremental MW from the FS unit at its adjusted incremental energy offer price of $38. Therefore, the FS unit sets the LMP at $38/MWh.

Proposed Practice: After MRT

Commitment Cost Treatment. If a FS unit is not instructed to shut down by the ISO after its MRT expires, then the proposed new treatment will also base pricing (after the FS unit's MRT expires) on an *adjusted incremental energy offer price.* However, because the FS unit's MRT has expired (and, in general, its Start-Up Fee recovered), the adjusted incremental energy offer price after the MRT will not incorporate the amortized Start-Up Fee.

More specifically, after the MRT expires, if it remains committed by the ISO, the FS unit's adjusted incremental energy offer price includes only the sum of two elements:

Incremental Energy Offer Price + Amortized No-Load Fee

As before the MRT expires, the No-Load Fee will remain amortized over the unit's EcoMax:

Amortized No-Load Fee = No-Load Fee / EcoMax MW

In Example 1, the FS unit's Incremental Energy Offer Price is $30 per MWh, and its Adjusted Incremental Energy Offer Price under the proposed new treatment after the MRT would be:

$30/MWh *energy* + $100 *no-load* per hr. / 50 MW = **$32/MWh.**

EcoMin Value Treatment. Under the proposed new treatment, the offered EcoMin of the FS unit is treated the same (and respected) in the dispatch solution before and after its MRT expires. However, like before, it is treated differently in the dispatch and in the pricing calculations:

[6] These 'pricing run quantities' are not the actual dispatch solution instructions (DDPs) that the units receive under the proposed new method. Rather, they are the solutions to the pricing optimization problem, and indicate how the pricing method determines the LMP.

- The dispatch solution is calculated treating the FS unit's EcoMin value as offered. In Example 1, the offered EcoMin is 50 MW.

- The pricing solution is calculated treating ("relaxing") the EcoMin value as zero. This treats the FS unit as if it has a broader dispatchable range, from 0 MW to its EcoMax (50 MW) in the pricing process.

Summary. The new table of the modified "characteristics" of used in the proposed pricing method for intervals after the FS unit's MRT are shown in the table below (this assumes the ISO continues to commit the FS unit after its MRT expires). The characteristics of the non-FS unit are unchanged.

Table 6 - Modified Offer Parameters Under Proposed Pricing Treatment, After MRT				
	FS unit		Non-FS unit	
EcoMin (MW)	~~50~~ 0		100	
EcoMax (MW)	50		500	
Adjusted Incremental Energy Offer Price (After MRT) ($/MWh)	~~30~~ ~~38~~ $32	~~50~~ 0 to 50 MW	$20	100 to 400 MW
			$60	400 to 500 MW

Proposed Practice: Dispatch and Pricing Outcomes After the MRT

Under the proposed new FS treatment, the dispatched MW for each unit will be calculated, in least-cost manner, using the resource's offered EcoMin and offer cost parameters. In Example 1, the least-cost dispatch under the proposed new treatment is the same before and after the MRT expires, and remains:

- Non-FS unit dispatch = 380 MW

- FS unit dispatch = 50 MW

The FS unit is block-loaded at 50MW, since its EcoMin of 50 MW is respected in the dispatch. The remaining 380 MW of demand is satisfied by the non-FS unit.

Pricing. Under the proposed new FS treatment, the price is calculated using the FS unit's Adjusted Incremental Energy Offer and 'relaxed' EcoMin value. These modified parameter values (for the pricing intervals after the expiration of the FS unit's MRT) are shown in Table 6. With these modified parameters, the pricing run would minimize total costs with pricing run quantities of:

- Pricing run quantity for the Non-FS unit = 400 MW

- Pricing run quantity for the FS unit = 30 MW

- LMP = **$32/MWh**, set by FS unit's adjusted offer price.

This pricing solution uses the least-expensive MW first, which are the 400 MW from the non-FS unit offered at \$20/MWh. Then the next expensive MW, which is from the FS unit at the \$32/MWh adjusted offer price. The pricing process would meet incremental demand at least-cost using an incremental MW from the FS unit, at its adjusted incremental energy offer price of \$32/MWh. Therefore, the FS unit sets the LMP at **\$32/MWh.**

Fast Start Unit's Net Revenue and Make-Whole Payments

In the proposed new treatment, the FS unit in Example 1 receives a 50 MW dispatch throughout this one-hour study period. Its amortized Start-Up and No-Load Fees are incorporated into its offer during its MRT. However, only amortized No-Load Fee is included in its adjusted incremental energy offer price after its MRT.

During the first 30 minutes (*i.e.*, during the FS unit's MRT), the FS unit's revenue from following its dispatch instruction is

$$50 \text{ MW} \times \$38/\text{MWh} \times 0.5 \text{ h} = \$950$$

For the second half of the hour, the LMP is \$32 and the FS unit's revenue is

$$50 \text{ MW} \times \$32/\text{MWh} \times 0.5 \text{ h} = \$800.$$

For the hour, the FS unit's total costs are:

$$\textit{Costs} = 50 \text{ MW} \times \$30/\text{MWh } \textit{energy} + \$150 \textit{ startup} + \$100 \textit{ no-load} = \$1{,}750.$$

The FS unit's net revenue for the hour is its total revenue minus total costs, or:[7]

$$\textit{Net revenue} = \$950 + \$800 - \$1750 = \$0$$

In other words, the FS unit breaks even *in the market* when it sets the LMP.

If the ISO elected to shut down this unit immediately after its MRT, the ISO's proposed FS pricing would allow this unit to recover all its incremental and commitment costs *in the market*. This is primarily due to two factors: first, the Start-Up and No-Load Fees of the FS unit are incorporated in its offer during its MRT; and second, the FS unit is marginal in the pricing run. If, instead of its MRT, the Start-Up Fee of the FS unit was amortized over a one hour run time (as in the ISO's current FS pricing method), or the FS unit was *not* the marginal unit (or an infra-marginal unit in the pricing run) in the pricing run, the LMP would be lower and a FS unit that is shut down economically at expiration of its MRT would not be able to break even in the market.

In sum, the FS unit in this example just breaks even and does not need any make-whole payment during the one-hour study period.

[7] The FS unit's unmodified offer cost parameters are used to calculate its net revenue.

Summary So Far

The table below summarizes the dispatch and pricing outcomes under current practice and the proposed new fast-start pricing method for Example 1.

Table 7 - Comparison of Dispatch and Pricing Outcomes for Example 1

	Current FS Pricing				**Proposed FS Pricing**			
	1st Commitment Interval of the FS Unit		**After the First Commitment Interval**		**During the MRT**		**After the MRT**	
Unit	**DDP (MW)**	**LMP ($/MWh)**	**DDP (MW)**	**LMP ($/MWh)**	**DDP (MW)**	**LMP ($/MWh)**	**DDP (MW)**	**LMP ($/MWh)**
FS unit	50	$35	50	$20	50	$38	50	$32
Non-FS unit	400		380		380		380	
Price Set by	FS Unit		Non-FS Unit		FS Unit		FS Unit	
Over Generation Instruction?	Yes (20 MW)		No		No		No	

The results summarized in Table 7 illustrate how the ISO's proposed FS pricing addresses the two problems identified at the outset of this memo:

1. By relaxing the minimum output of the FS unit in the pricing calculation (*i.e.* treating its EcoMin as 0 MW), the proposed solution allows an even block-loaded FS unit to supply the marginal MW in the pricing process, and to potentially set the LMP.

2. By respecting the FS units offered minimum output level in the dispatch process at all times, the proposed solution avoids the over-generation problem that occurs under current practice during the initial commitment (startup) phase.

Lost Opportunity Cost (LOC) for the Non-FS Unit in the New Pricing Method

The different assumptions about the minimum output of the FS unit in dispatch and pricing optimization problems could push down a unit against a higher-than-cost LMP and give rise to an opportunity cost issue that does not exist in today's FS pricing method.

Specifically, as a result of relaxing the minimum output of the FS unit to zero in the pricing process, the non-FS resource could receive a dispatch instruction that is

- Less than its current production capability, while
- Facing an LMP, now set by a FS unit, that exceeds the non-FS unit's energy offer price.

In this circumstance, the non-FS unit incurs a lost-opportunity cost by following its dispatch instruction. In effect, a unit may be 'held down against the price' in order to respect the EcoMin value of the fast-start unit in the dispatch solution, enabling the fast-start unit to set price.

The ISO recognizes this issue as part of its proposed FS pricing change, and recommends compensating the units that face such Lost Opportunity Costs (LOC). This LOC compensation is essential to ensure that a resource 'held down' in this situation does not have a financial incentive to deviate up from its assigned dispatch instruction when a FS unit sets the LMP.

Lost Opportunity Costs (LOC) in Example 1. In Example 1, the non-FS unit incurs such a lost-opportunity cost under the proposed pricing method. During the FS unit's MRT, the LMP is set by the FS unit at $38/MWh. As discussed shown following Table 5, the least-cost dispatch would send the non-FS unit a dispatch instruction of 380 MW. However, the non-FS unit can actually produce 400 MW at its energy offer price of $20/MWh, and $20/MWh is *below* the LMP. If the non-FS unit deviated from its dispatch instruction, it could earn an additional ($38 LMP – $20 offer cost) = $18 "deviation margin" for the next MWh of energy it produces.

This "deviation margin" creates a *lost opportunity cost.* Specifically, if the non-FS unit deviated from its dispatch instruction and instead produced 400 MW, the non-FS unit would increase its net revenue over the first half-hour by

(400 MW – 380 MW dispatch) × ($38 LMP – $20 offer) × .5 hour = $180

Put in other terms, by *following* its 380 MW dispatch as instructed, the non-FS unit incurs a *lost opportunity cost* of $180 over the first half hour.

Figure 1 (*next page*) illustrates graphically the lost opportunity cost of the non-FS unit in Example 1. The dispatch solution respects the FS unit's offered EcoMin value of 50 MW, and dispatches the non-FS unit to 380 MW as described previously. The pricing calculation relaxes the EcoMin of the FS unit to 0 MW. With a relaxed EcoMin, the pricing run solution finds the least-cost quantity from the FS unit is 30 MW and the pricing run quantity for the non-FS unit is 400 MW, as described previously (*see pages 12-13).*

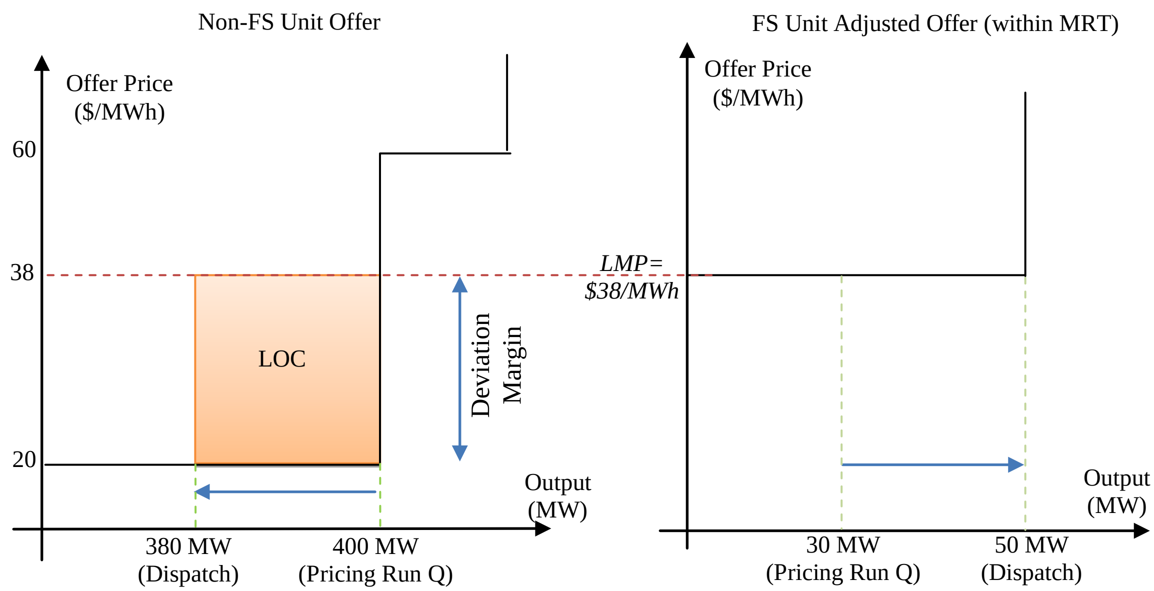

Figure 1- Calculation of the lost opportunity cost (LOC) in Example 1, for the non-fast start unit during the first 30 minutes of the fast-start unit's operation

In this situation, the non-FS unit's actual dispatch (of 380 MW) is below its 400 MW capability, facing an LMP of $38 per MWh set by the FS unit. As shown in Figure 1, the non-FS unit faces a deviation margin of $20 per MWh on each MW between 380 MW and 400 MW. The total lost opportunity cost of the non-FS unit is calculated as the area of the shaded rectangle in Figure 1, and is $180.

Now consider the calculation of the lost-opportunity cost over the second half-hour in Example 1. During the second half-hour, the price under the ISO's proposed method is $32/MWh. This again exceeds the $20/MWh offer price of the non-FS unit (at its dispatch instruction of 380 MW). The non-FS unit incurs a lost opportunity cost during the second half-hour of:

(400 MW – 380 MW dispatch) × ($32 LMP – $20 offer) × .5 hour = $120.

The non-FS unit's total lost opportunity cost for the hour is therefore $180 + $120 = **$300.**

Under the ISO's proposed implementation, an LOC (if it occurs) will be calculated for each 5-minute pricing interval. In the simplified context of Example 1, the LMP changes only once 30 minutes into the hour (at the expiration of the FS unit's MRT). So, in this example only, it is sufficient to calculate one set of LOCs for the first 30 minutes and another for the remaining 30 minutes of the hour. In general, the LOC must be calculated as often as the RT LMP may change – that is, every 5 minutes.

In Example 1, we assumed there are no reserve requirements (for simplicity). In practice, the 20 MW that the non-FS unit is "held down" in this example would be counted as additional reserves (this assumes the unit can ramp up to deliver the additional 20 MW, if needed, within 30 minutes or less). When reserve prices are positive, the additional reserve revenue on the 20 MW would tend to reduce the dollar value of the resource's LOC from following its dispatch of 380 MW, rather than deviating to the 400 MW level. The ISO's implementation will account for this incremental reserve revenue (if positive) as part of the non-FS unit's LOC calculation.

Why Is There No LOC When FS Units Operate under Current Practice?

Under the ISO's current FS pricing, no LOC is created for the non-FS unit. This is true before and after the initial commitment interval, although the ISO's current pricing methods differ before and after the initial commitment interval. Specifically:

1. In the first commitment interval, when the price is $35/MWh under current practice, the dispatch instruction sent to the non-FS unit is 400 MW. The non-FS unit has no additional capability to deviate above its assigned dispatch instruction without moving into its high-cost ($60/MWh) offer block, which would not be in its financial interest.

2. After the first commitment interval, the LMP is equal to the non-FS unit's incremental energy offer price of $20/MWh and the non-FS unit has no (that is, $0) 'deviation margin' on additional energy production. Therefore, there is no incentive for this unit to deviate from its DDP of 380 MW.

LOC Payments or MWP Payments: Which is Less?

Example 1 highlights a trade-off that is quite general between make-whole payments and lost-opportunity costs.

- Under current practice, the FS unit incurs a net loss and requires a MWP. However, the non-FS unit sets the LMP under current practice, and therefore incurs no LOC.

- Under the proposed new FS pricing method, the FS unit incurs no MWP in this example; however the non-FS unit incurs a LOC.

In general, the ISO's proposed new method will tend to lower the total MWP payable to FS units, which become more likely to set the LMP and therefore more likely to recover their total costs in the energy market (that is, without a MWP). However, the possibility that other units may be 'held down' in the least-cost dispatch facing a higher LMP set by a FS unit introduces a new need to compensate the other unit, in those specific situations, for its LOC.

Which is larger, the MWP to fast-start units under current practice, or the LOC payments under the ISO's proposed new method? In the context of Example 1, the answer is clear: The MWP due to the FS unit under current practice is $687.50. This is larger than the LOC payment due to the non-FS unit under the proposed practice of $300.

The ISO is presently performing large-scale simulations, using historical data for the ISO-NE system, to estimate whether this relationship should be expected to hold empirically for the system overall.

Amount of MW Eligible for LOC payment

In Example 1 under the proposed new method, the pricing run quantity of the FS unit is 30 MW, but the dispatch solution respects its offered EcoMin of 50 MW. The 20 MW difference is the amount by which the non-FS unit is "held down" in the dispatch solution to maintain power balance, *i.e.*, so that the sum of the dispatched MW of all units in the system is equal to the 430 MW load (*see* pages 10-12). The non-FS unit faces a 'deviation margin' on only the 20 MW that it was pushed below its pricing run quantity.

This is a general property: the total MW eligible for the LOC credit (that is, the total MW with a positive 'deviation margin') is equal to the MW difference (if positive) between (a) the offered EcoMin of the FS unit(s) (when a FS unit sets the LMP) and (b) the FS unit(s) quantities in the pricing run solution.[8] In Example 1 above, the pricing run quantity of the FS unit is 30 MW. It is below the FS unit's 50 MW EcoMin by 20 MW, which is the total MW *of the non-FS unit* that is eligible for LOC credit.

Because of this property, the ISO expects the amount of megawatts eligible for LOC credit to be relatively small when FS units are committed. When a single FS unit is operating and sets the LMP, the total system-wide MW that has a positive 'deviation margin' is no greater than the offered EcoMin value of the FS unit that sets the LMP.

Note that if there are multiple FS units operating at the same time, then the total MW eligible for the LOC credit is determined by the dispatch MW and pricing run quantities for *all* of the committed FS units. For example, suppose there are three committed FS units, each with an EcoMin of 10 MW. Each would receive a dispatch instruction of 10 MW, respecting its EcoMin. Suppose now that in the pricing run solution when the EcoMin values are relaxed to zero, two of the FS units receive pricing run quantities of zero MW, and the third receives a pricing run quantity of 5 MW and sets the LMP. In this scenario, there is a 25 MW difference between the 30 MW total offered EcoMin values of the FS units (when a FS unit sets the LMP) and the total FS units' quantities in the pricing run solution that amount to 5 MW. The amount of megawatts that may receive LOC credit system-wide in this scenario is 25 MW, not the 5 MW difference associated with just the FS unit that set the LMP.

LOC calculation if the non-FS unit produces <u>more</u> than its dispatch MW

In Example 1, the preceding calculation of the LOC for the non-FS unit explicitly assumed that the non-FS unit produced according to its assigned dispatch level of 380 MW. Now consider the calculation of the LOC payment if the non-FS unit in Example 1 produces *more* than its dispatch instruction.

In Example 1, if the non-FS unit produces <u>more</u> than its assigned dispatch of 380 MW, it will have a smaller MW range over which it has a deviation margin. This will lower the non-FS unit's LOC credit. This means that the non-FS unit cannot increase its net revenue by producing more than its assigned dispatch.

To illustrate how this works, suppose the non-FS unit overruns its dispatch instruction by 5 MW; that is, instead of producing 380 MW as dispatched, it produces is 385 MW. Assume, for

[8] If $Q_{FS,\ Pricing}$ stands for the pricing-run quantities of the committed FS units, the total MW (on *other* units across the system) eligible to receive an LOC credit is equal to: $\max\{0,\ Offered\ EcoMins_{FS} - Q_{FS,\ Pricing}\}$.

simplicity, this deviation from dispatch persists for the entire hour. With this deviation, the non-FS unit *realizes* part of the "deviation margin" it faced at its 380 MW DDP in its energy market revenue. In particular, for the first thirty minutes when the non-FS unit faces a deviation margin of $18 / MWh (*i.e.,* $38 LMP – $20 offer), it realizes additional net revenue in its energy market settlement of:

(385 MW – 380 MW output) × ($38 LMP – $20 offer) × .5 hour = $45

and in the second thirty minutes where it faces a deviation margin of $12 / MWh ($32 LMP – $20 offer), it realizes additional net revenue of:

(385 MW – 380 MW output) × ($32 LMP – $20 offer) × .5 hour = $30.

In sum, the non-FS unit realizes an additional $45+$30 = $75 net revenue over the hour.

Using the calculation method above to determine the LOC (*see* pages 15-16), in the first thirty minutes, the non-FS unit has a deviation margin of $18 / MWh on only the 15 MW (400 MW – 385 MW output) that it does not produce. Hence, in the first half-hour it faces an LOC of:

(400 MW – 385 MW output) × ($38 LMP – $20 offer) × .5 hour = $135.

Similarly, with $32/MWh LMP in the second half-hour, the non-FS unit faces a lower deviation margin of $12 / MWh on the 15 MW (400 MW – 385 MW output) that it does not produce. Hence, in the second half-hour it faces an LOC of:

(400 MW – 385 MW output) × ($32 LMP – $20 offer) × .5 hour = $90.

Therefore, if instead of following its actual dispatch instruction of 380 MW, the non-FS unit produces 385 MW, its total lost opportunity cost for the hour would be only $135 + $90= $225.

The sum of the non-FS unit's energy market net revenue on the 5 MW produced above its dispatch and the LOC credit that it receives when producing 385 MW is $75+$225 = $300. By design, this exactly equals the $300 LOC credit the non-FS unit would collect if it followed its 380 MW dispatch as assigned. In other words, with the proposed LOC credit design, the non-FS unit cannot increase its net revenue by producing more than its assigned dispatch MW.

LOC calculation if the non-FS unit produces <u>less</u> than its dispatch MW.

Under the ISO's proposed treatment, the LOC credit that an eligible unit receives will not be increased if the unit produces *less* than its dispatch MW. In other words, in the context of Example 1, the non-FS unit will not receive the "deviation margin" on MWs below its dispatch assignment. Because of this aspect of the LOC credit, the non-FS unit cannot increase its net revenue by producing below its assigned dispatch point. More likely, the non-FS unit would be financially worse off by producing less than its assigned dispatch, as compared to an output level equal to its assigned dispatch.

To illustrate how this works in the context of Example 1, suppose the non-FS unit produces 10 MW below its DDP: instead of 380 MW, its output is 370 MW for the entire hour. With this deviation, the non-FS unit *gives up* part of the energy market revenue it would have received with an output equal to its 380 MW DDP. In particular, in the first 30 minutes the non-FS forgoes an $18/MWh deviation margin ($38 LMP – $20 offer) on the 10 MW not produced, a total of $90:

(380 MW – 370 MW output) × ($38 LMP – $20 offer) × .5 hour = $90.

In the second half hour it foregoes a $12/MWh deviation margin ($32 LMP – $20 offer) for each MWh it does not produce, a total of $60:

(380 MW – 370 MW output) × ($32 LMP – $20 offer) × .5 hour = $60.

In sum, over the entire hour, the non-FS unit forgoes $90 + $60 = $150 net revenue.

At an output level of 370 MW, the non-FS unit faces an $18/MWh "deviation gap" for the next 30 MW of output.[9] In the ISO's proposed LOC design, this unit's LOC credit is limited to the amount that it would receive by following its DDP. In other words, at most, it will receive an LOC on the 20 MW difference between its actual dispatch of 380 MW and its pricing run quantity of 400 MW.

From an earlier calculation (*see* pages 15-16), the non-FS unit faces a $300 LOC *if* its output is equal to its 380 MW dispatch instruction. This unit cannot increase its LOC credit by lowering its output. So, if its output is only 370 MW, it would still receive an LOC equal to $300. In this case, from financial perspective, the unit is strictly worse off by producing less than its dispatch assignment: it forgoes net revenue of $150 on the 10 MW not produced.

The non-FS unit cannot increase its net revenue by deviating from its dispatch assignment

With the proposed LOC credit treatment, the non-FS unit is either:

a. Financially indifferent between producing its actual dispatch and deviating upward (*e.g.* between its 380 MW dispatch and an output of 385 MW), or is

b. Financially better off producing its actual dispatch than deviating downward (*e.g.* between its 380 MW dispatch and an output of 370 MW).

This is a general property. In each pricing interval, units that are eligible to receive an LOC credit cannot increase their net revenue by deviating from their dispatch instruction.

Key Takeaways of Example 1

The key takeaway points concerning the ISO's proposed new fast-start dispatch and pricing treatment illustrated in Example 1 are these:

1. During the Minimum Run Time of an ISO committed FS unit, its Start-Up Fee is amortized over its EcoMax and its MRT and incorporated into its energy offer price.

2. As long as a FS unit remains committed by the ISO, its No-Load Fee is amortized over its EcoMax and incorporated into its energy offer price.

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[9] We assume that the unit is not ramp-constrained and it can, in fact, increase its output by 30 MW if it so desires.

3. Because the dispatch solution respects FS units' submitted minimum output level, the dispatch instructions sent to resources do not result in over generation instructions.

4. Units that face a 'deviation margin' will be compensated for their lost-opportunity costs to ensure they do not face a financial incentive to deviate from their least-cost dispatch instruction.

Discussion: Does the ISO's Proposed Method Mean a Committed FS Unit Will Always Set the Price?

In general, the answer is no. There are many conditions when a committed fast-start resource may not set price, even if it is the highest cost resource operating at the time. There are good economic reasons for this, and in this section (and the following example) we explain this property in greater detail.

As noted previously, the proposed changes illustrated in the example above will make it more likely that committed fast-start units will set the LMP (relative to the current pricing method). However, this does not imply that that a committed fast-start unit will necessarily set price when it has higher offer price (as modified) than all other operating units. Rather, as noted previously in this memorandum, a committed fast-start resource will set the LMP when its output is "economically useful" in this dispatch interval (meaning, as before, that the power system's total production costs would be greater without the fast-start unit's output).

To illustrate this property, we modify the preceding example slightly. In this modified example, we assume demand has declined from the level in the previous example when the unit was committed (but we assume the unit is still within its Minimum Run Time, and therefore cannot be shut down yet). With lower demand, in the pricing run the unit's corresponding output would be zero – indicating that, even with a minimum output level treated as 0 MW, the least cost dispatch would find the unit's output *not* economically useful. In this case, the power system's total production costs would be *lower* without the fast-start unit's output, the resource is no longer "economically useful" for meeting the system's energy demand, and the fast-start unit would not set price.

Example 2

This example shows a set of conditions in which the FS unit is not economically useful and it will not set the price under the ISO's proposed FS pricing. The units considered in this example are exactly the same as those in Example 1.

The difference between Example 1 and Example 2 occurs because we shall assume that, after its first 15 minutes of operation, the system demand falls to 395 MW. This is lower than the level of 430 MW assumed in Example 1. As observed later in this example, at 395 MW it is optimal to shut down the FS unit once its MRT expires. Therefore, the study period is limited to the FS unit's 30-minute MRT.

As before, each unit has the attributes shown in the following table.

Table 8 - Offer Parameters for Example 2

	FS unit		Non-FS unit	
EcoMin (MW)	50		100	
EcoMax (MW)	50		500	
Incremental Energy Offer Price ($/MWh)	$30	50 MW	$20 $60	100 to 400 MW 400 to 500 MW

For Example 2, we will also assume:

- Energy demand is initially 430 MW as before, but now **falls to 395 MW** starting 15 minutes into the analysis period.
- The FS unit is initially off-line. It has a Start-Up Fee of $150 per start, a No-Load Fee of $100 per hour, and a Minimum Run Time (MRT) of ½ hour.
- The non-FS unit is online.
- For simplicity, no transmission constraints, reserve requirements, or energy losses are considered.
- The analysis period is **one-half hour**, which is the MRT of the FS unit.

Current Practice Outcomes

Because demand changes part-way through the commitment interval for the fast-start resource, the outcomes will differ at each dispatch level.

Under current practice, the pricing and dispatch outcomes for the first 15-minutes when demand is 430 MW are the same as presented in Example 1. Note that the LMP under current practice differs for the initial commitment (startup) interval and subsequent pricing intervals.

Outcomes at lower demand of 395 MW. After the first 15 minutes, the pricing and dispatch outcomes under current practice are determined using the methodology applicable for periods after the initial commitment (startup) interval. This uses the FS resource's incremental energy offer price, and respects the FS unit's offered minimum output level. The values of the two resource's parameters used for the dispatch and pricing calculations in this time period under current practice are the same as those shown above in Table 8.

Note that, during this period, the Start-Up and No-Load Fees of the FS unit are not incorporated into the energy offer price, and therefore are ignored in the current pricing solution.

For the parameters shown in Table 8 and 395 MW of total demand, the least-cost dispatch solution for Example 2 is:

- Non-FS unit dispatch = 345 MW
- FS unit dispatch = 50 MW

- LMP = **$20/MWh**, set by the non-FS unit's energy offer price.

The FS unit is block-loaded at 50MW, since its EcoMin of 50 MW is respected in the dispatch. The remaining 345 MW of demand is satisfied by the non-FS unit.

If demand increases by 1MW, to 396 MW, the output of the block-loaded FS unit would remain unchanged at 50 MW, and the next MW of energy demand would be met by the non-FS unit at its incremental energy offer price of $20 per MWh. Hence, at a load level of 395 MW anytime after the first commitment interval of the FS unit, under the current practice, the LMP is set by the non-FS unit at $20 per MWh.

Proposed New Method Outcomes

Because demand changes part-way through the commitment interval for the fast-start resource, the outcomes will also differ under the proposed new treatment at each dispatch level.

Under the new practice, the pricing and dispatch outcomes for the first 15-minutes when load are 430 MW are the same as presented in Example 1 (*see* pages 10-11).

Outcomes at lower demand of 395 MW. Under the proposed new FS treatment, the dispatched MW for each unit are calculated, in least-cost manner, using the resource's offered EcoMin and offer cost parameters. These are shown in prior Table 8. As discussed above, the least cost dispatch solution when demand is only 395 MW is:

- Non-FS unit dispatch = 345 MW
- FS unit dispatch = 50 MW

The FS unit is block-loaded at 50MW, since its EcoMin of 50 MW is respected in the dispatch. The remaining 345 MW of demand is satisfied by the non-FS unit.

Pricing. After the first 15 minutes but prior to expiration of the FS unit's Minimum Run Time, the pricing outcome under the proposed new treatment practice are determined using the methodology applicable for periods during the FS unit's Minimum Run Time. This uses the FS resource's adjusted incremental energy offer price, incorporating both Start-Up and No-Load Fee amortization. The values of the resources' parameters used for the pricing calculations in this time period (and before the MRT expires) are shown in Table 5 from Example 1.

Using the modified parameters shown in Table 5, applied to a total demand of only 395 MW, the pricing run would minimize total costs with pricing run quantities of:

- Pricing run quantity for the Non-FS unit = 395 MW
- Pricing run quantity for the FS unit = 0 MW
- LMP = **$20/MWh**, set by FS unit's adjusted offer price.

This pricing solution uses the least-expensive MW first, which are 395 MW of the 400 MW offered by the FS unit at $20/MWh. In the pricing run calculation, to satisfy the *next* MW of energy demand (if, say, demand increases by 1 MW, from 395 MW to 396 MW), the pricing process would meet demand at least-cost using an incremental MW from the non-FS unit at its offer price of $20. Therefore, the non-FS unit sets the LMP at $20/MWh when demand is only 395 MW.

In the pricing treatment when the minimum output of the FS unit is relaxed to zero, the optimal quantity of the FS unit is 0 MW. This indicates that *the FS unit is not economically useful* for meeting the system's current energy demand, and it is not marginal in the pricing solution.[10] As a result, the LMP will be set by another unit in the system (in this example, the only other unit in the system, the committed non-FS unit).

This outcome is sensible from an economic standpoint. In the pricing solution, the pricing run quantity of 0 MW for the FS unit indicates that the total cost of production in the system would be lower *without* the FS unit online, and its output is not economically useful for meeting total system demand. This is also a market signal that the FS unit should be shut down, and in this example would be de-committed by the ISO when its MRT expires (in this case, after it has operated for ½ hour in total).

Make Whole Payment (MWP) and Lost Opportunity Cost (LOC) Under Proposed Practice

The FS unit. During the study period in Example 2, the FS unit receives a dispatch instruction of 50 MW. By following its dispatch, it will earn net revenue of:

50MW × ($38/MWh LMP – $30/MWh *energy cost*) × 0.25 *hr run time*

+ 50MW × ($20/MWh LMP – $30/MWh *energy cost*) × 0.25 *hr run time*

– $150 *Startup Cost* – ($100 / *hr no-load cost* × 0.5 *hr run time*) = **– $225.**

During the second 15 minutes of the study period, the non-FS unit sets the price at $20/MWh and the FS unit incurs a $10/MWh loss for each MWh that it produces that that period. Moreover, it incurs a Start-Up Fee of $150/Start and a No-Load Fee of $100 per hour, incurring a net loss of $225 during on its 30 minute run time. The FS unit requires a MWP of $225.

Non-FS Unit. The lost opportunity cost (LOC) is calculated for every pricing interval. In Example 2, it incurs a LOC only for the first 15 minutes of the FS unit's operation, when demand is 430 MW and the FS unit set price.

Using the same logic for the non-FS unit's LOC in Example 1 (*see* pages 15 and 16), its LOC for following its dispatch instruction during the first 15 minutes = 0.25 hour is:

(400 MW – 380 MW dispatch) × ($38 LMP – $20 offer) × .25 hour = $90.

After the first 15 minutes, the LMP is set by the non-FS unit and it has no 'deviation margin': It cannot add to its profit by marginally changing its output. Hence, this unit does not face any LOC after demand falls to 395 MW. Its total LOC payment in Example 2 is therefore $90.

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[10] The converse is not necessarily the case. One can construct a case in which the FS unit is not economically useful (*i.e.* total cost of production of meeting a given level of load increases with the commitment of the FS unit) but it sets the price. For example, with the units above, when the load is 401 MW, even though the total cost of production with the committed FS unit is higher than that with only the non-FS unit in the system, the LMPs will be set by the FS unit at levels that match Example 1.

Reserve Pricing

Conceptually, under the proposed new FS pricing treatment, the ISO will continue to use the same co-optimization principles that are currently utilized for pricing real-time reserves.

The following example illustrates how the LMP and Reserve Market Clearing Price (RMCP) are co-determined under the proposed FS pricing method. As this example illustrates, under the proposed FS pricing solution, committed FS units can set the RMCP as well as the LMP.

Example 3

This example shows how the co-optimization concept is applied under the proposed FS pricing to determine the reserve and energy prices. For simplicity, we assume throughout Example 3 that the minimum run time of the FS unit has expired (thus its Start-Up Fee amortization can be ignored in this example). For this example, we will now assume there are three units in the system: one committed FS unit and two committed non-FS units. The table below summarizes the units' characteristics.

Table 9 - Offer Parameters For Example 3

	Block-loaded FS	Unit A (Non-FS)	Unit B (Non-FS)
Incremental Energy Offer ($/MWh)	100	20	15
EcoMin (MW)	20	50	50
EcoMax (MW)	20	100	100
No-Load Fee ($/hr)	1000	0	0
Online Reserve Capability (MW)	0	15	10

We further assume that:

- The study period is 1 hour.
- The FS unit is committed for the study period, and the non-FS units are online.
- The load is 195 MW and the reserve requirement is 16 MW.
- There is only one type of reserve requirement in this example.
- There is a high (*e.g.,* $1,000/MWh) penalty factor for a reserve violation, more commonly known as the Reserve Constraint Penalty Factor (or RCPF).
- For simplicity, no transmission constraints or energy losses are considered.

Current Practice Outcomes

Study period begins after the first commitment interval of the FS unit has elapsed. The pricing and dispatch outcomes under current practice are determined using the methodology applicable for periods after the initial commitment (startup) interval. This uses the FS resource's offered incremental energy offer price, and respects the FS unit's offered minimum output level. Moreover, under the current practice, the Start-Up and No-Load Fees of the FS unit are *not* incorporated into the energy offer price of this unit, and are ignored in the current pricing solution. The values of the resources' parameters used for the dispatch and pricing calculations in this time period under current practice are the same as those shown above in Table 9.

For the parameters shown in Table 9 and with 195 MW of energy demand and 16 MW of reserve requirement, the least-cost dispatch solution for Example 3 is:

- FS unit dispatch = 20 MW
- Non-FS Unit A: dispatch= 76 MW, reserve designation=15 MW
- Non-FS Unit B: dispatch= 99 MW, reserve designation=1 MW
- LMP = **$20/MWh**, set by the non-FS unit A's energy offer price
- RMCP= **$5/MWh**, set by the offer price difference between non-FS unit A and B

The committed FS unit is block-loaded at 20 MW and must receive a dispatch of 20MW. The remaining 175 MW of demand (195 MW load – 20 MW from FS unit) must be met with the two non-FS units.

In meeting the reserve requirement, whenever possible, it is optimal to use the maximum reserve capability of the *more* expensive unit before turning to the less expensive unit. In this example, the non-FS unit B provides the most economic MW in the system and therefore, is used to the highest possible extent to supply energy. Since (the more expensive) non-FS unit A has a maximum reserve capability of 15 MW of reserves, to meet the 16 MW reserve requirement, the less expensive non-FS unit B must provide at least 1 MW of reserves. Thus the optimal dispatch solution assigns Unit B to produce 99 MW of power and preserves 1 MW of reserve capability on the unit. The remaining 76 MW needed to meet the 195 MW load is supplied by non-FS unit A.

Market Prices. Under current practice, the LMP is set by unit A. If demand increases by 1 MW, the least-cost means to satisfy this incremental energy demand is to increase non-FS unit A's output by 1 MW, to 77 MW. This is because if the output of the non-FS unit B is increased by 1 MW, the amount of reserves available from this unit will drop by 1 MW to zero – and the system will fail to meet the 16 MW reserve requirement. The additional cost of increasing unit A's output from 76 MW to 77 MW is $20/MWh. Hence, under the current practice, the LMP is set by the non-FS unit A at $20 per MWh.

To determine the reserve price (RMCP), we make two observations: first, the FS unit is block-loaded and cannot provide any reserves when supplying 20 MW of output (its unloaded capability in reserve is zero MW). Second, the non-FS unit A is already designated with its maximum reserve capability of 15 MW. Therefore, if the *reserve requirement* increases from 16 MW to 17 MW, the additional increment of required reserves must be supplied by non-FS unit B.

Increasing the reserves carried on non-FS unit B requires re-dispatching Unit A as well. Specifically, to provide an incremental 1 MW of reserves, the output of non-FS unit B must be lowered to 98 MW, resulting in 2 MW of reserve capability on this unit. By doing this, the system will save the incremental energy offer price of unit B on 1 MW of energy it no longer produces, or $15/MWh. Meanwhile, to still meet the system's energy balance, the output of non-FS unit A must be increased by 1 MW, to 77 MW. By taking this action the system incurs an additional cost equal to the incremental energy offer of unit A, or $20/MWh. Taken together, the net change in the system's total cost to meet an additional 1 MW increment in the reserve requirement is the cost of this energy redispatch, or $5 per MWh:

$20/MWh *(increase in costs from Unit A)* – $15/MWh *(decrease in costs from Unit B)*

Hence, under the current practice, the RMCP is set by the redispatch of non-FS units A and B, and equals $5 per MWh.

Proposed New Method Outcomes

After the expiration of the FS unit's Minimum Run Time, the pricing outcomes under the proposed new treatment are determined using the methodology applicable for periods after the FS unit's Minimum Run Time.

Commitment Cost Treatment. If a FS unit is not instructed to shut down by the ISO after its MRT expires, then the proposed new treatment will also base pricing (after the FS unit's MRT expires) on an *adjusted incremental energy offer price*. However, because the FS unit's MRT has expired, the adjusted incremental energy offer price after the MRT will not incorporate the amortized Start-Up Fee.

More specifically, after the MRT expires, if it remains committed by the ISO, the FS unit's adjusted incremental energy offer price includes only the sum of two elements:

Incremental Energy Offer Price + Amortized No-Load Fee

As before the MRT expires, the No-Load Fee will remain amortized over the unit's EcoMax:

Amortized No-Load Fee = No-Load Fee / EcoMax MW

In Example 3, the FS unit's Incremental Energy Offer Price is $100 per MWh, and its Adjusted Incremental Energy Offer Price under the proposed new treatment after the MRT would be:

$100/MWh *energy* + $1000 *no-load* per hr. / 20 MW = **$150/MWh.**

EcoMin Value Treatment. Under the proposed new treatment, the offered EcoMin of the FS unit is treated the same (and respected) in the *dispatch* solution before and after its MRT expires. However, like before, it is treated differently in the dispatch and in the *pricing* calculations:

- The dispatch solution is calculated treating the FS unit's EcoMin value as offered. In Example 3, the offered EcoMin of the FS unit is 20 MW.
- The pricing solution is calculated treating ("relaxing") the EcoMin value as zero. This treats the FS unit as if it has a broader dispatchable range, from 0 MW to its EcoMax (20 MW) in the pricing process.

Summary. The new table of the modified "characteristics" used in the proposed pricing method for intervals after the FS unit's MRT are shown in the table below (this assumes the ISO continues to commit the FS unit after its MRT expires). The characteristics of the non-FS units are unchanged.

Table 10 – Adjusted Offer Parameters In Example 3			
	Block-loaded FS	Unit A (Non-FS)	Unit B (Non-FS)
Adjusted Incremental Energy Offer ($/MWh)	~~100~~ 150	20	15
EcoMin (MW)	~~20~~ 0	50	50
EcoMax (MW)	20	100	100
No-Load Fee ($/hr)	1000	0	0
Online Reserve capability (MW)	0	15	10

Proposed Practice: Dispatch and Pricing Outcomes

Dispatch. Under the proposed new FS treatment, the dispatched MW for each unit is calculated, in least-cost manner, using the resource's offered EcoMin and offered cost parameters. These are shown in prior Table 9. As discussed above, the least cost dispatch solution when load is 195 MW and the reserve requirement is 16 MW is:

- FS unit: DDP= 20 MW, reserve designation = 0 MW
- Non-FS Unit A: dispatch= 76 MW, reserve designation=15 MW
- Non-FS Unit B: dispatch= 99 MW, reserve designation=1 MW

Pricing. Under the proposed new FS treatment, the price is calculated using the FS unit's Adjusted Incremental Energy Offer and 'relaxed' EcoMin value. These modified parameter values (for the pricing intervals after the expiration of the FS unit's MRT) are shown in Table 10. With these modified parameters, the pricing run would minimize total costs with pricing run quantities of:

- FS unit: Pricing run quantity = 11 MW, reserve designation = 0 MW
- Non-FS Unit A: Pricing run quantity = 85 MW, reserve designation = 15 MW
- Non-FS Unit B: dispatch= 99 MW, reserve designation = 1 MW
- LMP = **$150/MWh**, set by the FS unit's adjusted energy offer price
- RMCP= **$135/MWh**, set by the relative energy offer price of the non-FS unit A and the adjusted offer price of the FS Unit.

In the pricing solution, the amount of reserves that can be provided by the FS unit is still limited by its dispatch (relative to its capacity). Since the FS unit in this example is block-loaded and its actual dispatch of 20 MW equals its maximum output of 20 MW (*i.e.* it has *no* unloaded capability in reserve), the FS unit cannot contribute any reserves in the pricing run solution.

Hence, as before, the reserve requirement must be met by the two non-FS units. Similar to the results under current practice, because the non-FS unit A (which is more expensive than the other non-FS unit) cannot provide more than 15 MW of reserves, to meet the reserve requirement, the non-FS unit B, which provides the least expensive MW in the system, must also provide at least 1 MW of reserves. Thus, the maximum pricing run quantity for the non-FS unit B is 99 MW, calculated as:

Unit B: 100 MW *EcoMax* – 1 MW *reserves* = 99 MW *dispatch*.

To satisfy the 16 MW reserve requirement, the more expensive non-FS unit A must provide the remaining 15 MW. So its pricing run quantity is 85 MW, calculated as:

Unit A: 100 MW *EcoMax* – 15 MW *reserves* = 85 MW *dispatch*.

The total output of unit A and unit B leaves only 11 MW to be met with the most expensive resource, the FS unit.

The LMP. The sum of pricing run quantity and pricing run reserve designations is equal to EcoMax in both non-FS units. Since the sum of reserve designations in the two non-FS units is exactly equal to the reserve requirement, it is impossible to increase the non-FS units' pricing run quantities without violating reserves requirement constraint. The MW from the FS unit are priced at its adjusted offer price of $150/MWh (which is less than $1,000/MWh cost of a reserve requirement violation). Therefore, the optimal response to a 1 MW increase in energy demand is to increase the output of the FS unit, rather than violate the reserve requirement. Hence, the FS unit sets the LMP at $150/MWh.

The RMCP. To determine the reserve price (RMCP), evaluate the re-dispatch costs if the reserve requirement is increased by 1 MW, from 16 MW to 17 MW. As before, since the FS unit in this example is online with an actual dispatch of 20 MW equal to its maximum output of 20 MW (*i.e.* it has *no* unloaded capability in reserve), no reserves are counted on the FS unit. Since Unit A already supplies its maximum reserve capability, the additional increment of required reserves must be supplied by non-FS unit B.

Increasing the reserves carried on non-FS unit B requires re-dispatching. Specifically, to provide an incremental 1 MW of reserves, the output of non-FS unit B must be lowered to 98 MW, resulting in 2 MW of reserve capability on this unit. By doing this, the system will save the incremental energy offer price of unit B on 1 MW of energy it no longer produces, or $15/MWh. Meanwhile, in the pricing run solution, the least-cost means to satisfy total load is to increase the pricing run quantity from *the fast start unit.* We cannot increase the output from unit A in the redispatch, or we will violate the total reserve requirement (at a cost of $1,000 / MW, the reserve shortage price).

Taken together, the net change in the system's total cost to meet an additional 1 MW increment in the reserve requirement in the pricing run solution is the cost of dispatching the FS unit up by 1 MW, and dispatching Unit B down by 1 MW. This difference is $135 per MWh:

$150/MWh *(increase in costs from FS unit)* – $15/MWh *(decrease in costs from Unit B)*

Hence, under the proposed treatment, the co-optimized re-dispatch in the pricing solution will produce a RMCP equal to $135 per MWh.

Make Whole Payment (MWP) and Lost Opportunity Cost (LOC) Under Proposed Practice

The FS unit. During the study period in Example 3, the FS unit receives a dispatch instruction of 20 MW and provides no reserves. By following its dispatch, it will earn net revenue of:

20 MW × ($150/MWh *LMP* – $100/MWh *incremental energy cost*) × 1 *hr run time*

– ($1000 / hr *no-load fee* × 1 hr *run time*) = ***$0*.**

As expected, when the FS unit is marginal (in the pricing solution) and sets the LMP, its net profit is zero.[12] The FS unit recovers its costs in the energy market, and does not require a make-whole payment.

Non-FS Unit A. The lost opportunity cost (LOC) is calculated for every pricing interval. In Example 3, under the proposed FS pricing method, the LMP is $150/MWh and the RMCP is $135/MWh. The (more expensive) FS unit participates in setting both prices.

Facing the LMP of $150/MWh, the non-FS unit A has a profitable deviation margin. It can deviate from its actual 76 MW dispatch instruction and increase its output to 85 MW without sacrificing any of its designated reserve MW and associated revenues. Using the same logic for the non-FS unit's LOC in Example 1 (*see* pages 15-16), its LOC following its dispatch instruction (assuming a one hour period) is:

(85 MW *output* – 76 MW *dispatch*) × ($150 *LMP* – $20 *offer*) × 1 hour = $1,170.

The non-FS Unit A faces an LOC of $1,170 for following its DDP, relative to deviating from its dispatch to 85 MW.

A few additional calculations show that Unit A's LOC cannot be greater than the case just evaluated, for a deviation of 85 MW. If this unit increases its output to 86 MW, it will increase its energy revenue by an additional $150 *LMP* - $20 *Offer* = $130 / MWh. Meanwhile, this unit will no longer be able to provide 15 MW of reserves: its reserves supplied measurement would fall by 1 MW to 14 MW. That reduces the revenues earned from reserves by the value of the $135/MWh RMCP. In net, an increase in the output from 85 MW to 86 MW would lower the net revenue of unit A by $5. Generally, we can show that unit A would not find it profitable to increase its output beyond 85 MW. As a result, $1,170 is the LOC of non-FS unit A.

Non-FS Unit B. Again, using the same logic for the non-FS unit's LOC in Example 1 (*see* pages 15-16), the non-FS unit B has no profitable deviation margin. If it deviates from its 99 MW DDP and increases its output to 100 MW, it can no longer provide any reserves and will no longer receive the reserve revenue by following its 99 MW DDP. Such a deviation changes unit B's net revenues by:

(100 MW *output* – 99 MW *dispatch*) × ($150 *LMP* – $15 *offer*) × 1 hour +

(0 MW *reserves @ 100 MW output* – 1 MW *reserves @ DDP*) × $135 *RMCP* × 1 hour

= $135 *increase in energy revenue* – $135 *decrease in reserves revenue*

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[12] This is not a general property. In general, because amortization of Start-Up and No-Load Fees are done over FS unit's EcoMax, a non block-loaded FS unit that is marginal in the pricing run might not be able to recover its costs and incur a loss.

= \$0.

The non-FS Unit B does not face any LOC by producing at its assigned dispatch (DDP).

Summary of Results in Example 3

The following table summarizes the numerical results in Example 3.

With the relaxed EcoMin value in the pricing run solution, the FS unit sets the LMP for energy at its Adjusted Incremental Energy Offer price of \$150 / MWh.

The co-optimized energy and reserve pricing sets the reserve market clearing price at the system redispatch costs, as determined in the pricing run solution, associated with an incremental increase in the reserve requirement. The RMCP is \$135 / MWh. This preserves the dispatch-following incentives of units assigned to provide reserves (rather than energy), such as low-cost unit A, as instructed in the actual dispatch.

	Unit	DDP (MW)	Reserves Provided (MW)	LMP (\$/MWh)	RMCP (\$/MWh)	Payments in the Market (\$)	Side Payments (\$)	Costs (\$)	Net Rev. (\$)
Current FS Pricing	FS unit	20	0			\$400	\$2,600	\$3,000	\$0
	Non-FS unit A	76	15	\$20	\$5	\$1,595	\$0	\$1,520	\$75
	Non-FS unit B	99	1			\$1,985	\$0	\$1,485	\$500
Proposed FS Pricing	FS unit	20	0			\$3,000	\$0	\$3,000	\$0
	Non-FS unit A	76	15	\$150	\$135	\$13,425	\$1,170	\$1,520	\$13,075
	Non-FS unit B	99	1			\$14,985	\$0	\$1,485	\$13,500

Appendix A. Additional Numerical Examples

Example A-1: A FS unit with a dispatchable range

The purpose of this example is to show how dispatch and pricing solutions are determined with a fast-start unit with dispatchable range.

For Example A-1 let the FS and non-FS units have modified characteristics as follows:

Table 11 - Offer Parameters for Example A-1

	FS unit		Non-FS unit	
EcoMin (MW)	50		100	
EcoMax (MW)	200		500	
Start-Up Fee ($/start)	250		0	
Incremental Costs ($/MWh)	$30 $40 $50	50 to 60 MW 60 to 75 MW 75 to 200 MW	$20 $60	100 to 400 MW 400 to 500 MW

It is assumed that this example is solved over a period of 1 hour. The Minimum Run Time of the FS unit is now assumed to be 1 hour. Furthermore, it is assumed that the non-FS unit must remain committed for the 1-hour study period. For simplicity, no system losses or transmission constraints are considered. No-Load Fees of both units are $0 per hour.

Let the energy demand be 430MW, as in Example 1.

Commitment Costs under the Current Pricing and Dispatch Solution

Commitment cost during the first commitment interval (Current FS Pricing)

To identify the pricing solution under the current FS pricing method, the FS unit's offer is modified by the amortized commitment cost: its Start-Up Fee is amortized over its EcoMax and 1 hour, and its No-Load Fee is amortized over its EcoMax. Therefore, during the first commitment interval, the "marginal" cost of the FS unit will increase by *$250/(200 MW×1 h)+($0/h)/200 MW = $1.25/MWh*.

In addition, the EcoMin of the FS unit is "relaxed" to zero. *I.e.*, the FS unit is assumed to be completely dispatchable between 0 MW and its EcoMax (200 MW).

The new table of the modified "characteristics" of the units in the system is shown below.

Table 12 - Modified Offer Parameters in the First Commitment Interval for Example A-1 (Current FS Pricing)				
	FS unit		Non-FS unit	
EcoMin (MW)	~~50~~ 0		100	
EcoMax (MW)	200		500	
~~Start-Up Fee ($/start)~~	~~250~~		~~0~~	
Incremental Costs ($/MWh)	~~30~~ $31.25 ~~40~~ $41.25 ~~50~~ $51.25	~~50~~ 0 to 60 MW 60 to 75 MW 75 to 200 MW	$20 $60	100 to 400 MW 400 to 500 MW

Dispatch and Pricing During the First Commitment Interval (Current FS Pricing)

The current FS pricing and dispatch method uses the table above in the first commitment interval. With no lumpiness in the FS unit, the optimal solution after this relaxation has the FS unit producing 30 MW and the non-FS unit producing 400 MW. This is because to achieve a solution with the lowest possible production costs, it is optimal to first use the least expensive megawatts in the system. Those are supplied by the non-FS unit at $20/MWh. Since the 400 MW supplied by the non-FS unit is not enough to meet the 430 MW load, the 30 MW balance of load must be supplied by the next least expensive set of megawatts in the system. Those are provided by the FS unit at modified cost of $31.25/MWh.

The solution above is used to determine the DDPs of the units in the system. The non-FS unit receives a DDP equal to the 400 MW solution above. However, since generating below 50 MW is not feasible for the FS unit, instead of the 30 MW solution from the pricing problem above, it would receive a DDP equal to its EcoMin (50 MW). Total dispatched output is: 400 + 50 = 450 MW. This means that, in the absence of other interventions, the system would have 20 MW of over generation. In practice, the 20 MW of over generation instruction is offset by the regulation-down service.

In addition, the relaxed FS unit EcoMin results in the next MW of load coming from the FS unit at the (modified) incremental cost of $31.25/MWh. Thus, the market outcomes in the first commitment interval are:

$$(DDP^1_{FS}, DDP^1_{non\text{-}FS}) = (50, 400)$$

$$LMP^1_{current} = \mathbf{\$31.25/MWh.}$$

During the first commitment interval, the sum of the DDPs sent to resources is 450MW, which is 20 MW higher than the 430MW load.

Commitment cost after the first commitment interval (Current FS Pricing)

Under the current FS Pricing, after the first commitment interval, no element of the unit's commitment cost is included in the pricing. In addition, the EcoMin of the FS unit is no longer relaxed to zero. *I.e.*, after the first commitment interval of the FS unit, the physical characteristics of this unit are preserved under the pricing and dispatch optimization problems and the original table of units' characteristics is restored:

Table 13 - Modified Offer Parameters after the First Commitment Interval for Example A-1 (Current FS Pricing)				
	FS unit		Non-FS unit	
EcoMin (MW)	50		100	
EcoMax (MW)	200		500	
Start-Up Fee ($/start)	250		0	
Incremental Costs ($/MWh)	$30 $40 $50	50 to 60 MW 60 to 75 MW 75 to 200 MW	$20 $60	100 to 400 MW 400 to 500 MW

Dispatch and Pricing after the First Commitment Interval (Current FS Pricing)

In the current FS pricing and dispatch method, after the first commitment interval of the FS unit, the unmodified table of characteristics (Table 11) is used. The output of the FS unit cannot be less than 50MW, leaving a *maximum* of 380 MW of the load to be satisfied by the non-FS unit. Because the non-FS unit provides the least expensive 400 MW in the system, the optimal solution to the dispatch problem would entail having the FS unit produce at its EcoMin of 50MW and the non-FS unit at 380MW:

$$(DDP^2_{FS}, DDP^2_{non\text{-}FS})=(50, 380)$$

If the load "incrementally" changes[13] by 1MW to 431MW, the least expensive way to meet the additional load is to increase the output of the (less expensive) non-FS unit at the cost of $20/MWh. The optimal output of the FS unit would remain unchanged at 50MW. Hence, after the first commitment interval of the FS unit, the LMP is set by the incremental cost of the non-FS unit:

$$LMP^2_{current} = \$20/MWh.$$

Net Revenue under Current FS Pricing

The non-FS unit. Suppose that the first commitment interval of the FS unit is 5 minutes (1/12 h). Under the current FS pricing method, the net revenue of the non-FS unit from following its DDP are:

$$400MW\times(\$31.25/MWh-\$20/MWh)\times 1/12h+380\ MW\times(\$20/MWh-\$20/MWh)\times 11/12h=\mathbf{\$375.}$$

During its first commitment interval, the FS unit sets the price at $31.25/MWh making the non-FS unit infra-marginal. After the first commitment interval of the FS unit, the non-FS unit becomes marginal and receives zero net revenue. So, in this example, all the net revenue of the non-FS unit comes from the first commitment interval in which it was infra-marginal.

[13] The Tariff defines the real time LMP based on the "next increment of load," acknowledging that the increment could be positive or negative. For simplicity, this memo only considers positive incremental changes in load. In the vast majority of cases, prices are identical for positive and negative changes.

The FS unit. The DDP-following net revenue of the FS unit under the current FS pricing method is:

*50MW×($31.25/MWh-$30/MWh)×1/12h +50 MW× ($20/MWh-$30/MWh)× 11/12h-$250/Start= **–$703.125.***

During its first commitment interval, the FS unit sets the price at its modified cost of $31.25/MWh. Because its offer is modified by the amortized commitment costs, the FS unit makes a relatively small profit in this interval. After the first commitment interval, the non-FS unit becomes marginal and the FS unit incurs a $10/MWh loss for each MWh that it produces. Moreover, it incurs a Start-Up Fee of $250/Start to bring its total loss to $703.125. To remain online and follow its DDP, the FS unit would need a MWP of $703.125 to cover its losses.

Economic Commitment and Dispatch under the ISO's proposed FS pricing

It is optimal to commit the FS unit. Suppose that FS unit was not committed and only the non-FS unit was online to serve the 430 MW load. The cost of serving 430MW by the non-FS unit is the sum of the cost of the first 400 MW at $20/MWh and the additional 30MW at $60/MWh:

$20/MWh× 400 MW ×1 h+ $60/MWh× 30 MW ×1h=$9,800.

If the FS unit is committed at its EcoMin, the non-FS unit will produce at 380 MW and the FS unit will generate 50MW. Total cost of serving the 430 MW load would be:

$20/MWh× 380 MW ×1 h+ $30/MWh× 50 MW ×1h+$250/Start=$9,350.

Hence, it is more efficient to commit the FS unit as this decision achieves the minimum total production cost of meeting the 430 MW load.

Optimal Dispatch Instructions. Once the FS unit is committed, its output must be at least its EcoMin of 50 MW. The Unit Dispatch System will not dispatch the FS unit beyond its EcoMin. This is because if an additional MW is produced by the FS unit at $30/MWh, then to meet the energy balance constraint the non-FS unit must reduce its output by 1 MW, saving the system only $20/MWh. In net, the total cost of production will increase by $10/MWh. Thus, the DDP of the FS unit is its EcoMin of 50MW and the DDP of the non-FS unit is 380MW:

$$(DDP_{FS}, DDP_{non\text{-}FS})=(50, 380)$$

Prices. In the pricing run the offers of the FS unit are modified in two ways: [14]

1. The EcoMin of the FS unit is relaxed to 0 MW.

2. Amortized commitment cost is added to the FS unit's offers. In doing so, during the MRT of the FS unit, the Start-Up Fee of this unit is amortized over its EcoMax and MRT. In this example, *$250/(200 MW× 1h)=$1.25/MWh* is added to the incremental cost of the FS unit.[15] Note that since the No-Load Fee is assumed to be $0/h, no additional amortization of commitment costs is needed.

[14] Note that in Example A-1, we have assumed the MRT of the FS unit is the study period of 1 hour. The pricing *after* the MRT is not considered in this example.

[15] With zero No-Load Fees, the Start-Up Fee is the only commitment cost component that is considered.

The modified characteristics of the units are shown in the following table.

Table 14 - Modified Offer Parameters During the MRT for Example 3 (Proposed FS Pricing)

	FS unit		Non-FS unit	
EcoMin (MW)	~~50~~ 0		100	
EcoMax (MW)	200		500	
Start-Up Fee ($/start)	~~250~~ 0		0	
Adjusted Incremental Energy Offer Price ($/MWh)	~~30~~ $31.25	~~50~~ 0 to 60 MW	$20	100 to 400 MW
	~~40~~ $41.25	60 to 75 MW	$60	400 to 500 MW
	~~50~~ $51.25	75 to 200 MW		

In the problem above, with non-lumpy FS unit, the least expensive megawatts in the system, provided by the non-FS unit at $20/MWh, are used first. The second set of MW in economic order belongs to the FS unit (which, under pricing run, can be dispatched at its relaxed EcoMin of 0 MW). All 400MW offered at $20/MWh and 30MW of those offered at (modified level) of $31.25/MWh are used to meet the 430MW demand. Therefore, meeting 430MW of load at the lowest production cost results in the following quantities in the pricing run for the FS and non-FS units:

$$(Q_{FS}, Q_{non\text{-}FS})_{pricing}=(30, 400).$$

If the load increases to 431MW, the additional MW of generation to meet the load should come from the FS unit at the (modified) cost of $31.25/MWh instead of the non-FS unit at $60/MWh. Therefore:

$$LMP=\$31.25/MWh.$$

Calculation of Side Payments (Make Whole Payment and Lost Opportunity Cost)

In calculating side payments, the proposed FS pricing methodology assumes that units in the system would take the LMP as given.

Non-FS Unit. With *LMP=$31.25/MWh*, the net revenue of the non-FS unit at its DDP is:

$$(\$31.25/MWh - \$20/MWh)\times 380\ MW = \$4,275.$$

However, with the LMP of $31.25/MWh, the non-FS unit can produce an additional 20MW at a cost below the LMP: it would have a financial incentive to deviate from its DDP of 380 MW and generate 400MW. Its net revenue with an output of 400MW is:

$$(\$31.25/MWh - \$20/MWh)\times 400\ MW = \$4,500$$

The non-FS unit does not want to produce more than 400MW because each additional MW costs more than the LMP. At its DDP of 380MW, the non-FS unit faces an opportunity cost of: *$4,500-$4,275= $225:*

$$LOC_{non\text{-}FS}=\$225$$

This is the same result that we would have obtained if we calculated the LOC using the *deviation margin* method discussed in Example 1 (*see* pages 15 and 16):

(400 MW – 380 MW dispatch) × ($31.25 LMP – $20 offer) × 1 hour =$225.

FS Unit. By following its DDP, the FS unit incurs a $187.50 loss:

($31.25/MWh - $30/MWh) × 50 MW - 250 = – $187.50

Therefore, it will need a MWP of $187.50.

Summary of DDP, LMP, and Side Payments under the proposed method

Table below summarizes the outcome of the market in ISO's proposed FS pricing in this example:

Unit	**DDP (MW)**	**LMP ($/MWh)**	**Payments in the Market ($)**	**Side Payments ($)**	**Costs ($)**	**Net revenue ($)**	**Consumer Expenditure[16] ($)**
FS unit	50	$31.25	$1,562.50	$187.50	$1,750	0	$13,850
Non-FS unit	380		$11,875	$225	$7,600	$4,500	

[16] Consumer Expenditure is the sum of all the side payments and all the payments made in the market.

Example A-1: Comparing the outcomes under the current and proposed FS pricing mechanisms

Load is 430 MW and the first commitment interval of the FS unit is 5 minutes. The study period is 1 hour.

<table>
<tr><th></th><th colspan="6">Current FS Pricing</th><th colspan="4">Proposed FS Pricing</th></tr>
<tr><th></th><th colspan="2">First Commitment Interval (5 min)</th><th colspan="2">After the First Commitment Interval</th><th>Net revenue in the market</th><th>MWP</th><th colspan="2">During the MRT</th><th>Net revenue in the market</th><th>MWP and LOC</th></tr>
<tr><td>Unit</td><td>DDP (MW)</td><td>LMP ($/MWh)</td><td>DDP (MW)</td><td>LMP ($/MWh)</td><td>$</td><td>$</td><td>DDP (MW)</td><td>LMP ($/MWh)</td><td>$</td><td>$</td></tr>
<tr><td>FS unit</td><td>50</td><td rowspan="2">$31.25</td><td>50</td><td rowspan="2">$20</td><td>-$703.13</td><td>$703.13</td><td>50</td><td rowspan="2">$31.25</td><td>-$187.50</td><td>$187.50</td></tr>
<tr><td>Non-FS unit</td><td>400</td><td>380</td><td>$375</td><td>--</td><td>380</td><td>$4275</td><td>$225</td></tr>
<tr><td>Price Set by</td><td colspan="2">FS Unit</td><td colspan="2">Non-FS Unit</td><td></td><td></td><td colspan="2">FS Unit</td><td></td><td></td></tr>
<tr><td>Over-Generation Instruction</td><td colspan="2">Yes (20 MW)</td><td colspan="2">No</td><td></td><td></td><td colspan="2">No</td><td></td><td></td></tr>
</table>

Appendix B. Mathematical Formulations

This Appendix B provides a mathematical representation of the fast-start dispatch and pricing optimization solutions discussed in Examples 1 and 2. We also provide a brief introduction to the 'cost envelope' concepts commonly used in these mathematical formulations, and that is employed in the linear programming formulation of Examples 1 and 2 below.

Notation. In the optimization problems below, $p_{non\text{-}FS}$ and p_{FS} are respective production points (output) the non-FS and the FS units. In addition, c_{FS} and $c_{non\text{-}FS}$ are the costs of production by the FS and non-FS units, respectively. The LMP is the shadow price of the power balance constraint in the corresponding pricing runs (*i.e.* $LMP=\lambda$).

Cost Envelopes

Resources can submit up to 10 price-quantity pairs to reflect their (non-decreasing) incremental costs. Suppose a resource submits N pairs: $(b_1, q_1), \ldots, (b_N, q_N)$. These price-quantities mean that the resource's incremental cost between 0 and q_1 is b_1, between q_1 and q_2 is b_2, …, and between q_{N-1} and q_N is b_N. The non-decreasing incremental cost property means that: $b_1 \le b_2 \le \ldots \le b_N$.

Then, (ignoring commitment costs), the linear minimum cost envelope constraints are given by:

$$
\begin{aligned}
&C_0(X) = 0 \\
&C_1(X) = b_1 X \\
&C_i(X) = b_i X + C_{i-1}(q_{i-1}) - b_i q_{i-1} \\
&\vdots \\
&C_N(X) = b_N X + C_{N-1}(q_{N-1}) - b_N q_{N-1}
\end{aligned}
$$

If commitment costs are included a fixed Startup and No-Load Fee will be added to each of the functions above.

For example, if $p_{non\text{-}FS}$ is the output of the non-FS unit, using the formulas above, the cost of the non-FS unit is example 5 is given by:

$$
\begin{aligned}
&C_1(p_{non-FS}) = 20\,p_{non-FS} \\
&C_2(p_{non-FS}) = 60\,p_{non-FS} + 20 \times 400 - 60 \times 400
\end{aligned}
$$

Or using the *minimum* cost envelope:

$$
\begin{aligned}
&c_{non-FS} \ge 20\,p_{non-FS} \\
&c_{non-FS} \ge 60\,p_{non-FS} - 16{,}000
\end{aligned}
$$

The minimum cost envelope constraint for the FS unit in Example 3 (excluding its $250 Start-Up Fee) is:

$$c_{FS} \geq 30\,p_{FS}$$
$$c_{FS} \geq 40\,p_{FS} - 600$$
$$c_{FS} \geq 50\,p_{FS} - 1,350$$

Mathematical Specification of Examples 1 and 2

Current FS Pricing

Using the concept of minimum cost envelope, Pricing and Dispatch optimization in the first commitment interval can be written as:

$$\begin{array}{lll}
\min_{c,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
 & \cancel{\text{EcoMin}_{FS}}\ 0 \leq p_{FS} \leq 50 & \text{FS EcoMin relaxed to 0 MW} \\
 & EcoMin_{non-FS} \leq p_{non\text{-}FS} \leq 500 & \\
 & c_{FS} \geq 35\,p_{FS} & \text{Amortized SU and NL included} \\
 & c_{non\text{-}FS} \geq 20\,p_{non\text{-}FS} & \\
 & c_{non\text{-}FS} \geq 60\,p_{non\text{-}FS} - 16000 &
\end{array}$$

But the DDPs will respect the EcoMins:

$$DDP_i = \max\left\{p^*{}_i, EcoMin_i\right\}, i \in \left\{FS, non - FS\right\}$$

The pricing and dispatch problem *after* the first commitment interval can be written as:

$$\begin{array}{lll}
\min_{c,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
 & EcoMin_{FS} \leq p_{FS} \leq 50 & \text{FS EcoMin Respected} \\
 & EcoMin_{non-FS} \leq p_{non\text{-}FS} \leq 500 & \\
 & c_{FS} \geq 30\,p_{FS} & \text{No Amortized SU and NL costs} \\
 & c_{non\text{-}FS} \geq 20\,p_{non\text{-}FS} & \\
 & c_{non\text{-}FS} \geq 60\,p_{non\text{-}FS} - 16000 &
\end{array}$$

DDPs will respect the EcoMins. The constraints are modeled into the optimization problem.

$$DDP_i = \max\left\{p^*{}_i, EcoMin_i\right\}, i \in \left\{FS, non - FS\right\} \quad \leftarrow \text{Redundant}$$

Proposed FS Pricing

Under the proposed FS pricing, the pricing problem within the FS unit's MRT is:

$$\begin{array}{lll}
\min_{c\,,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
 & \cancel{\text{EcoMin}_{FS}}\ 0 \le p_{FS} \le 50 & \text{FS EcoMin relaxed to 0 MW} \\
 & EcoMin_{non-FS} \le p_{non\text{-}FS} \le 500 & \\
 & c_{FS} \ge 38\,p_{FS} & \text{Amortized SU and NL included (within MRT)} \\
 & c_{non\text{-}FS} \ge 20\,p_{non\text{-}FS} & \\
 & c_{non\text{-}FS} \ge 60\,p_{non\text{-}FS} - 16000 &
\end{array}$$

And the pricing *after* the FS unit's MRT can be expressed as:

$$\begin{array}{lll}
\min_{c\,,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
 & \cancel{\text{EcoMin}_{FS}}\ 0 \le p_{FS} \le 50 & \text{FS EcoMin relaxed to 0 MW} \\
 & EcoMin_{non-FS} \le p_{non\text{-}FS} \le 500 & \\
 & c_{FS} \ge 32\,p_{FS} & \text{After MRT, amortized no-load is included} \\
 & c_{non\text{-}FS} \ge 20\,p_{non\text{-}FS} & \\
 & c_{non\text{-}FS} \ge 60\,p_{non\text{-}FS} - 16000 &
\end{array}$$

The Economic Dispatch Problem respects the committed FS unit's EcoMin and does not include any commitment cost amortization:

$$\begin{array}{lll}
\min_{c\,,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & \\
 & EcoMin_{FS} \le p_{FS} \le 50 & \text{FS EcoMin respected} \\
 & EcoMin_{non-FS} \le p_{non\text{-}FS} \le 500 & \\
 & c_{FS} \ge 30\,p_{FS} & \text{No amortized commitment cost inluded} \\
 & c_{non\text{-}FS} \ge 20\,p_{non\text{-}FS} & \\
 & c_{non\text{-}FS} \ge 60\,p_{non\text{-}FS} - 16000 &
\end{array}$$

Appendix C: Mathematical Specifications of Example 3

In the optimization problems below, p_a, r_a, p_b, r_b, p_{FS}, and $r_{non\text{-}FS}$ are respective production points (output) and provided reserves of the non-FS units A and B, and the FS unit. In addition, $viol_{reserves}$ is the system reserve deficiency.

The LMP and Reserve Price in the current FS pricing are the shadow prices of the Economic Dispatch Optimization Problem energy and reserve constraints, respectively (*i.e.* $LMP=\lambda_{ED}$ and $RMCP=\mu_{ED}$).

The LMP and Reserve Price in the proposed FS pricing are the shadow prices of the pricing run optimization energy and reserve constraints, respectively (*i.e.* $LMP=\lambda$ and $RMCP=\mu$).

The cost of a reserve violation is *$1,000/MWh*.

Economic Dispatch Optimization

The economics dispatch problem can be expressed as:

$$\min_{p,r,viol} \quad c_a + c_b + c_{FS} + c_{viol}$$

$$\begin{aligned}
\text{s.t.} \quad & p_a + p_b + p_{FS} = \text{Load} && \lambda_{ED} \\
& r_{FS} + r_a + r_b + viol_{\text{reserves}} \geq \text{Reserve Requirement} && \mu_{ED} \\
\\
& EcoMin_a \leq p_a \leq EcoMax_a \\
& 0 \leq r_a \leq \text{Unit A Reserve Capability} \\
& p_a + r_a \leq EcoMax_a \\
& c_a \geq 20 p_a \\
\\
& EcoMin_b \leq p_b \leq EcoMax_b \\
& 0 \leq r_b \leq \text{Unit B Reserve Capability} \\
& p_b + r_b \leq EcoMax_b \\
& c_b \geq 15 p_b \\
\\
& EcoMin_{FS} \leq p_{FS} \leq EcoMax_{FS} \\
& 0 \leq r_{FS} \leq \text{FS Online Reserve Capability} \\
& p_{FS} + r_{FS} \leq EcoMax_{FS} \\
& c_{FS} \geq 100 p_{FS} \\
& r_{FS} + EcoMin_{FS} \leq EcoMax_{FS} \\
\\
& c_{viol} \geq 1000 viol_{\text{reserves}} \\
& viol_{\text{reserves}} \geq 0.
\end{aligned}$$

Pricing Run Optimization

$$\min_{p,r,viol} \quad c_a + c_b + c_{FS} + c_{viol}$$

s.t.

$$p_a + p_b + p_{FS} = \text{Load} \qquad \lambda$$
$$r_{FS} + r_a + r_b + viol_{\text{reserves}} \geq \text{Reserve Requirement} \qquad \mu$$

$$EcoMin_a \leq p_a \leq EcoMax_a$$
$$0 \leq r_a \leq \text{Unit A Reserve Capability}$$
$$p_a + r_a \leq EcoMax_a$$
$$c_a \geq 20 p_a$$

$$EcoMin_b \leq p_b \leq EcoMax_b$$
$$0 \leq r_b \leq \text{Unit B Reserve Capability}$$
$$p_b + r_b \leq EcoMax_b$$
$$c_b \geq 15 p_b$$

$$\cancel{EcoMin_{FS}}\ 0 \leq p_{FS} \leq EcoMax_{FS}$$
$$0 \leq r_{FS} \leq \text{FS Online Reserve Capability}$$
$$p_{FS} + r_{FS} \leq EcoMax_{FS}$$
$$c_{FS} \geq \cancel{100}\ 150\, p_{FS}$$
$$r_{FS} + EcoMin_{FS} \leq EcoMax_{FS}$$

$$c_{viol} \geq 1000 viol_{\text{reserves}}$$
$$viol_{\text{reserves}} \geq 0.$$

Mathematical Specification of Example A-1

Current FS Pricing

Using the concept of minimum cost envelope, the dispatch and pricing problem during the FS unit's first commitment interval can be written as:

$$
\begin{array}{lll}
\min_{c\,,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
& \cancel{50}\ 0 \le p_{FS} \le 200 & \text{FS EcoMin Relaxed} \\
& 100 \le p_{non\text{-}FS} \le 500 & \\
& c_{FS} \ge \cancel{30}\ 31.25 p_{FS} & \text{(SU+ NL) over FS EcoMax and 1 h} \\
& c_{FS} \ge \cancel{40}\ 41.25 p_{FS} - 600 & \\
& c_{FS} \ge \cancel{50}\ 51.25 p_{FS} - 1350 & \\
& c_{non\text{-}FS} \ge 20 p_{non\text{-}FS} & \\
& c_{non\text{-}FS} \ge 60 p_{non\text{-}FS} - 16000. &
\end{array}
$$

After the FS unit's first commitment interval, the dispatch and pricing problem can be written as:

$$
\begin{array}{lll}
\min_{c\,,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
& 50 \le p_{FS} \le 200 & \text{FS EcoMin Respected} \\
& 100 \le p_{non\text{-}FS} \le 500 & \\
& c_{FS} \ge 30 p_{FS} & \text{No Amortized SU and NL costs} \\
& c_{FS} \ge 40 p_{FS} - 600 & \\
& c_{FS} \ge 50 p_{FS} - 1350 & \\
& c_{non\text{-}FS} \ge 20 p_{non\text{-}FS} & \\
& c_{non\text{-}FS} \ge 60 p_{non\text{-}FS} - 16000. &
\end{array}
$$

Proposed FS Pricing

Using the concept of minimum cost envelope, the Economic Dispatch optimization can be written as:

$$
\begin{array}{ll}
\min_{c,\,p} & c_{FS} + c_{non\text{-}FS} \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} \\
& 50 \le p_{FS} \le 200 \\
& 100 \le p_{non\text{-}FS} \le 500 \\
& c_{FS} \ge 30\,p_{FS} \\
& c_{FS} \ge 40\,p_{FS} - 600 \\
& c_{FS} \ge 50\,p_{FS} - 1350 \\
& c_{non\text{-}FS} \ge 20\,p_{non\text{-}FS} \\
& c_{non\text{-}FS} \ge 60\,p_{non\text{-}FS} - 16000.
\end{array}
$$

The pricing problem can be written as:

$$
\begin{array}{lll}
\min_{c,\,p} & c_{FS} + c_{non\text{-}FS} & \\
\text{s.t.} & p_{FS} + p_{non\text{-}FS} = \text{Load} & (\lambda) \\
& \cancel{50}\ 0 \le p_{FS} \le 200 & \\
& 100 \le p_{non\text{-}FS} \le 500 & \\
& c_{FS} \ge \cancel{30}\ 31.25\,p_{FS} & \text{(SU+ NL) over FS EcoMax and MRT} \\
& c_{FS} \ge \cancel{40}\ 41.25\,p_{FS} - 600 & \\
& c_{FS} \ge \cancel{50}\ 51.25\,p_{FS} - 1350 & \\
& c_{non\text{-}FS} \ge 20\,p_{non\text{-}FS} & \\
& c_{non\text{-}FS} \ge 60\,p_{non\text{-}FS} - 16000. &
\end{array}
$$

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