November 8, 2016

<u>VIA ELECTRONIC FILING</u>

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

Re: *ISO New England Inc.*, Docket No. ER17-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2020-2021 Capacity Commitment Period

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee, (together, the "Filing Parties"),[2] hereby electronically submits to the Federal Energy Regulatory Commission ("Commission") this transmittal letter and related materials which identify the following values for the 2020-2021 Capacity Commitment Period,[3] which is associated with the eleventh Forward Capacity Auction ("FCA"): (i) Installed Capacity Requirement;[4] (ii) Local Sourcing Requirement for the Southeastern New England ("SENE") Capacity Zone;[5] (iii) Maximum Capacity Limit for the Northern New England ("NNE") Capacity Zone;[6] (iv) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (v) Marginal Reliability Impact

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[1] 16 U.S.C. § 824d (2014).

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

[3] The 2020-2021 Capacity Commitment Period starts on June 1, 2020 and ends on May 31, 2021.

[4] Capitalized terms used but not otherwise defined in this filing have the meanings ascribed thereto in the ISO's Transmission, Markets and Services Tariff (the "Tariff").

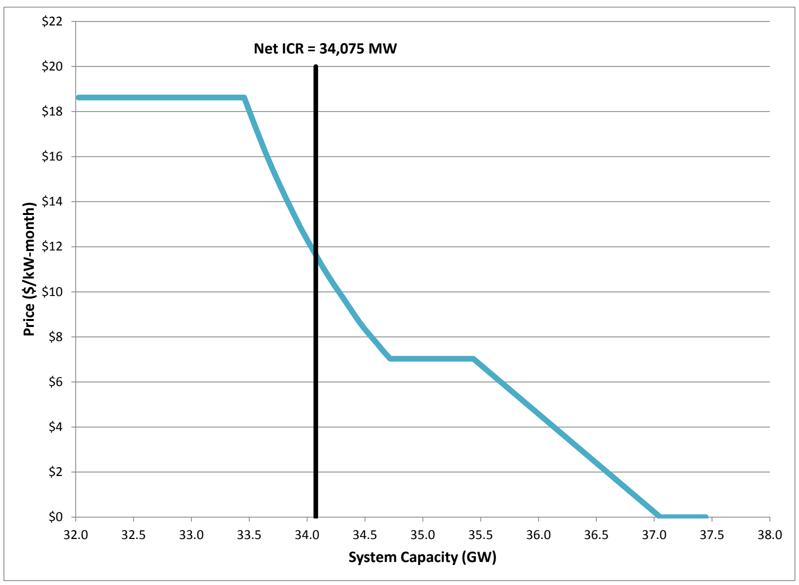
[5] The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA") and Northeastern Massachusetts ("NEMA")/Boston and Rhode Island Load Zones.

[6] The NNE Capacity Zone includes the Maine, New Hampshire and Vermont Load Zones.

("MRI") Demand Curves.[7] The Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, HQICCs and MRI Demand Curves are collectively referred to herein as the "ICR-Related Values." [8]

The ISO is proposing an Installed Capacity Requirement (net of HQICCs) of 34,075 MW,[9] a Local Sourcing Requirement for the SENE Capacity Zone of 9,810 MW, a Maximum Capacity Limit for the NNE Capacity Zone of 8,980 MW, HQICCs of 959 MW per month, and the following MRI Demand Curves:

1. System-Wide Capacity Demand Curve for the Eleventh FCA

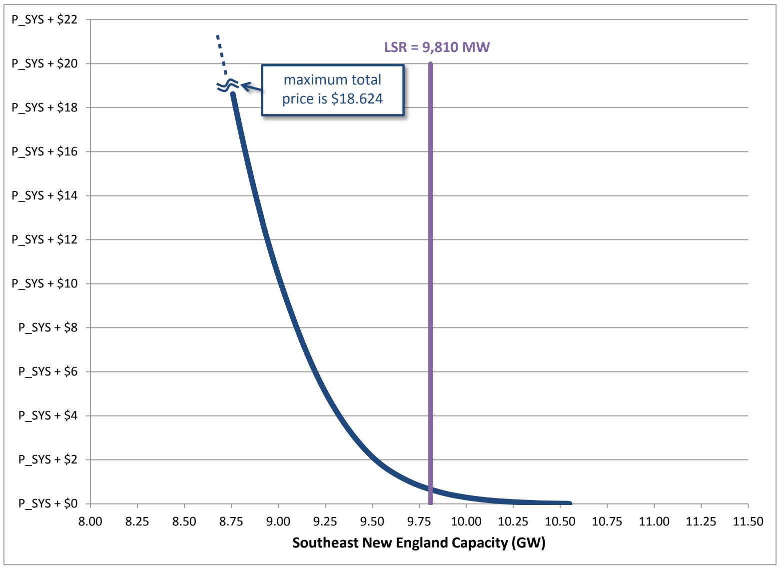


[7] As explained in this filing letter, the MRI Demand Curves include the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone. The Commission accepted the MRI Demand Curve design, including the transitional design, on June 28, 2016.

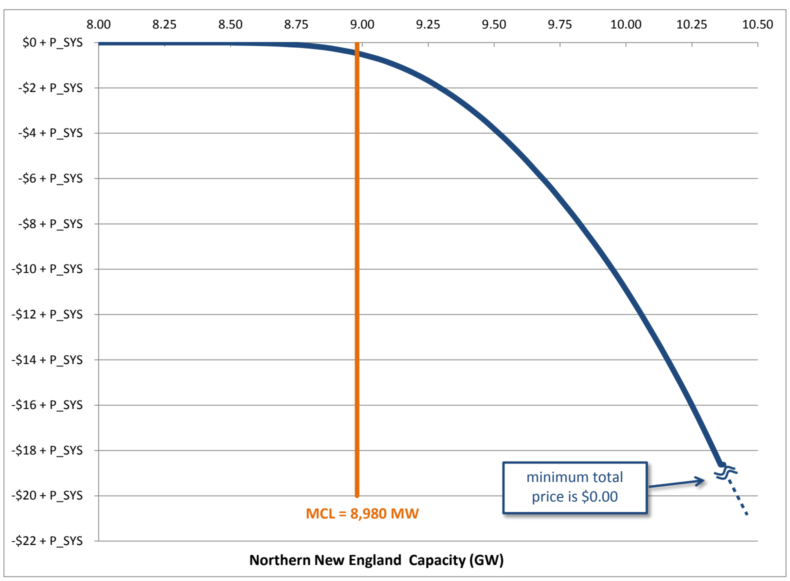
[8] Pursuant to Section III.12.3 of the Tariff, the Installed Capacity Requirement must be filed 90 days prior to the applicable FCA. The eleventh FCA, which is the primary FCA for the 2020-2021 Capacity Commitment Period, is scheduled to commence on February 6, 2017.

[9] As explained in Section III.B.4 of this filing letter, the proposed Installed Capacity Requirement reflects tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Quebec in the aggregate amount of 1,950 MW.

2. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for the Eleventh FCA



3. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone for the Eleventh FCA



The derivation of the ICR-Related Values is discussed in Sections III-VI of this filing letter, and in the attached joint testimony of Carissa Sedlacek, Director of Resource Adequacy at the ISO, and Maria Scibelli, Principal Analyst, Resource Adequacy at the ISO (the "Sedlacek-Scibelli Testimony"). The Sedlacek-Scibelli Testimony is sponsored solely by the ISO.

Beginning with the eleventh FCA, the ISO is required to develop the System-Wide Demand Curve by using the MRI methodology to procure capacity.[10] Using the MRI methodology, for the first time this year, the ISO must also develop Import-Constrained Capacity Zone Demand Curves and Export-Constrained Capacity Zone Demand Curves. Accordingly, using the MRI Demand Curve methodology accepted by the Commission in an order dated June 28, 2016,[11] the ISO has developed the MRI Demand Curves. Additionally, as explained in Section III.B.1 of this filing letter and in the Sedlacek-Scibelli Testimony, the methodology used to reflect the photovoltaic ("PV") forecast in the calculations of the ICR-Related Values as a reduction in the load forecast assumption has slightly changed from the methodology that was used for the 2019-2020 Capacity Commitment Period. Other than those modifications, the ICR-Related Values were calculated using the same Commission-approved methodology that has been used to calculate the values submitted and accepted for other recent Capacity Commitment Periods.[12] Accordingly, the Commission should accept the proposed values without change to become effective on January 7, 2017.

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[10] While system-wide capacity demand curves were developed for the ninth and tenth FCAs, a linear methodology was used to develop those demand curves.

[11] *ISO New England Inc. and New England Power Pool Participants Committee*, 155 FERC ¶ 61,319 (2016). In its order, the Commission accepted the new demand curve design as well as a transition mechanism for the System-Wide Capacity Demand Curve. The transition curve is a hybrid of the previous linear demand curve design and the new MRI-based design.

[12] *ISO New England Inc.*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2019-2020 Capacity Commitment Period, Docket No. ER16-307-000, at 2 ("2019-2020 ICR Filing") (filed Nov. 10, 2015). The 2019-2020 ICR Filing was accepted in *ISO New England Inc.*, 154 FERC ¶ 61,008 (2016) ("2019-2020 ICR Order"); *ISO New England Inc.*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2018-2019 Capacity Commitment Period, Docket No. ER15-325-000, at 4-6 ("2018-2019 ICR Filing") (filed Nov. 4, 2014). The 2018-2019 ICR Filing was accepted in *ISO New England Inc.*, 150 FERC ¶ 61,003 (2015) ("2018-2019 ICR Order"); *ISO New England Inc. and New England Power Pool Participants Committee*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2017-2018 Capability Year, Docket No. ER14-328-000, at 5-6 ("2017-2018 ICR Filing") (filed Nov. 5, 2013). The 2017-2018 ICR Filing was accepted by Letter Order issued December 30, 2013 (the "2017-2018 ICR Letter Order"). *ISO New England Inc. and New England Power Pool Participants Committee*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2016-2017 Capability Year, Docket No. ER13-334-000, at p. 5 ("2016-2017 ICR Filing") (filed Nov. 6, 2012). The 2016-2017 ICR Filing was accepted by Letter Order issued December 31, 2012 (the "2016-2017 ICR Letter Order"). *See also ISO New England Inc. and New England Power Pool*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits

I. DESCRIPTION OF FILING PARTY AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO plans and 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, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

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

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and Related Values for the 2015-2016 Capability Year, Docket No. ER12-756-000, at p. 5 ("2015-2016 ICR Filing") (filed Jan. 3, 2012); *ISO New England Inc.*, Letter Order accepting filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2015-2016 Capability Year, Docket No. ER12-756-000 (Feb. 23, 2012) ("2015-2016 ICR Letter Order"); *ISO New England Inc. and New England Power Pool*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2014-2015 Capability Year, Docket No. ER11-3048-000, at 5-6 ("2014-2015 ICR Filing") (filed March 8, 2011); *ISO New England Inc. and New England Power Pool*, 135 FERC ¶ 61,135 at P 53 (2011) ("2014-2015 ICR Order"); *ISO New England Inc.*, Letter Order accepting filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2013-2014 Capability Year, Docket No. ER10-1182-000 (June 25, 2010) ("2013-2014 ICR Letter Order"); *ISO New England Inc.*, Letter Order accepting filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2012-2013 Capability Year, Docket No. ER09-1415-000 (Aug. 14, 2009) ("2012-2013 ICR Letter Order"); *ISO New England Inc.*, Order Accepting, With Conditions, Proposed Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits, and Related Values, 125 FERC ¶ 61,154 at PP 1, 26, 41 (2008) (accepting ISO-proposed Installed Capacity Requirements for the 2011-2012 Capability Year) ("2011-2012 ICR Order"); *ISO New England Inc. and New England Power Pool*, 121 FERC ¶ 61,250 at P 1 (2007); *order on reh'g*, 123 FERC ¶ 61,129 (2008) ("2010-2011 ICR Order").

And to NEPOOL as follows:

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II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values for the 2020-2021 Capacity Commitment Period 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."[14] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[15] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[16] 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."[17] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[18] 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.[19]

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[13] 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.

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

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

[16] *Id.* at 9.

[17] *Cities of Bethany, et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984).

[18] *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (*citing Cities of Bethany*, 727 F.2d at 1136).

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

III. INSTALLED CAPACITY REQUIREMENT

A. Description of the Installed Capacity Requirement

The Installed Capacity Requirement is a measure of the installed resources that are projected to be necessary to meet reliability standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity to meet reliability standards. More specifically, the Installed Capacity Requirement is the amount of resources needed to meet the reliability requirements defined for the New England Control Area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE") no more than once every ten years (a LOLE of 0.1 days per year). The methodology for calculating the Installed Capacity Requirement is set forth in Section III.12 of the Tariff.

The ISO is proposing an Installed Capacity Requirement of 35,034 MW for the 2020-2021 Capacity Commitment Period. This value reflects tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Quebec in the aggregate amount of 1,950 MW. However, the 35,034 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 959 MW per month is applied to reduce the portion of the Installed Capacity Requirement that is allocated to the Interconnection Rights Holders ("IRH"). Thus, the net Installed Capacity Requirement, after deducting the HQICC value, is 34,075 MW.[20]

B. Development of the Installed Capacity Requirement

With the exception of the MRI Demand Curve methodology (described in Section VI of this filing letter) and the slight change in the methodology used to account for PV resources in the load forecast (described in Section III.B.1 of this filing letter), the calculation methodology used to develop the ICR-Related Values for the 2020-2021 Capacity Commitment Period is the same as that used to calculate the values for previous Capacity Commitment Periods. As in previous years, the values for the instant filing are based on assumptions relating to expected system conditions for the Capacity Commitment Period. These assumptions include the load forecast, resource capacity ratings, resource availability, and relief assumed obtainable by implementation of operator actions during a capacity deficiency, which includes the amount of possible emergency assistance (tie benefits) obtainable from New England's interconnections with neighboring Control Areas and load reduction from implementation of 5% voltage reductions.[21] The methodology used to develop the assumptions generally is the same as that used

[20] The net Installed Capacity Requirement is used in the development of the MRI Demand Curves, which will be used to procure capacity in the eleventh FCA.

[21] Sedlacek-Scibelli Testimony at 23-33.

to calculate the Installed Capacity Requirement and related values for the previous Capacity Commitment Periods.[22] The modeling assumptions have been updated to reflect changed system conditions since the development of the Installed Capacity Requirement and related values for the 2019-2020 Capacity Commitment Period. These updated assumptions are described below.

1. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2020-2021 Capacity Commitment Period are one major input into the calculation of the ICR-Related Values. For the purpose of calculating the Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period, the ISO used the forecast published in the 2016 – 2025 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2016 ("2016 CELT Report").[23] The 2016 CELT Report forecast was developed by the ISO using the same methodology that the ISO has used for determining load forecasts in previous years and to develop the peak load assumptions reflected in the Commission-approved Installed Capacity Requirement in previous years.[24] This methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee.[25]

The projected New England Control Area summer 50/50 peak load[26] for the 2020-2021 Capacity Commitment Period is 29,601 MW. In determining the Installed Capacity Requirement, the load forecast is represented by a weekly probability distribution of daily peak loads. This probability distribution is meant to quantify the New England weekly system peak load's relationship to weather. The 50/50 peak load is used solely for reference purposes. In the Installed Capacity Requirement calculations, the methodology determines the amount of capacity resources needed to meet every expected peak load of the weekly distribution given the probability of occurrence associated with that load level.[27]

Similar to last year, the ICR-Related Values reflect a PV forecast. This year, there is a

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[22] *See* note 12, *supra*.

[23] Sedlacek-Scibelli Testimony at 13-14.

[24] *See, e.g.*, 2019-2020 ICR Order; 2018-2019 ICR Order; 2017-2018 ICR Letter Order; 2016-2017 ICR Letter Order; 2015-2016 ICR Order; 2014-2015 ICR Order at PP 53, 69; 2013-2014 ICR Letter Order; 2012-2013 ICR Letter Order; 2011-2012 ICR Order at PP 5-6; 2010-2011 ICR Order at PP 5-6.

[25] The methodology is reviewed periodically and updated when deemed necessary in consultation with the NEPOOL Load Forecasting Committee.

[26] The New England Control Area is a summer-peaking system, meaning that the highest load occurs during the summer. The 50/50 peak refers to the peak load having a 50% chance of being exceeded, and is expected to occur at a weighted New England-wide temperature of 90.4 ºF.

[27] *See* Sedlacek-Scibelli Testimony at 11-14.

slight modification in the methodology used to reflect the PV forecast in the calculation of the ICR-Related Values. In order to reflect the 2016 PV forecast in the calculation of the ICR-Related Values for the 2020-2021 Capacity Commitment Period, the ISO categorized PV facilities into three types: (1) PV resources that participate as resources in the FCM and that are modeled for the Capacity Commitment Period of interest if they qualify to participate in that Capacity Commitment Period; (2) PV resources that do not participate in the FCM but participate in the energy market as Settlement Only Resources; and (3) in-service behind-the-meter PV facilities and behind-the-meter PV facilities forecasted to be installed prior to the Capacity Commitment Period of interest, which reduce system load and are not part of any ISO markets ("BTM PV").[28]

In the calculations of the ICR and related values for the 2019-2020 Capacity Commitment Period, BTM PV was further subdivided into two subcategories, behind-the-meter PV embedded in load ("BTMEL") and behind-the-meter PV not embedded in load ("BTMNEL"). BTMNEL was then reflected in the calculation of the ICR and related values for the 2019-2020 Capacity Commitment Period. Unlike last year, in the 2016 PV forecast, full reconstitution of PV output in both of the BTM subcategories (BTMEL and BTMNEL) was taken into account in the historical loads used to develop the long-term load forecast. This allowed the ISO to combine these two subcategories into one category, *i.e.* BTM PV.[29] Thus, the forecasted amount of BTM PV was deducted from the load forecast used to calculate the ICR-Related Values for the 2020-2021 Capacity Commitment Period.

In order to determine the load reduction impact of BTM PV resources, the ISO used coincident hourly load and PV production data for the years 2012-2015. The ISO derived some of this data from publically available data sources, and distribution utilities also provided data. The ISO calculated the PV value for the net load scenario for 2020-2021, then adjusted the load forecast by this forecasted BTM PV.[30] This adjustment resulted in a 720 MW reduction in the Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period.

2. Resource Capacity Ratings

The Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period is based on the latest available resource ratings[31] at the time of the Installed Capacity Requirement

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[28] Sedlacek-Scibelli Testimony at 14.

[29] *Id*.

[30] The development of the 2016 PV forecast is further explained in the Sedlacek-Scibelli Testimony at 15-17.

[31] The resource capacity ratings for the 2020-2021 Capacity Commitment Period were calculated in accordance with Section III.12.7.2 of the Tariff using the methods and procedures that were employed for calculating resource

calculation of Existing Capacity Resources that have qualified for the eleventh FCA. These resources are described in the qualification informational filing for the eleventh FCA that is being filed concurrently on November 8, 2016.[32]

Resource additions and attritions are not assumed in the calculation of the Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period, pursuant to the Tariff, because there is no certainty which new resource additions or existing resource attritions, if any, will clear the auction. The use of the proxy unit for potential required resource additions when the system is short of capacity, and the additional load carrying capability ("ALCC") adjustments to remove surplus capacity from the system, discussed in the Sedlacek-Scibelli Testimony, are designed to address these resource addition and attrition uncertainties.[33]

3. Resource Availability

The proposed Installed Capacity Requirement value for the 2020-2021 Capacity Commitment Period reflects generating resource availability assumptions based on historical scheduled maintenance and forced outages of these capacity resources.[34] For generating resources, individual unit scheduled maintenance assumptions are based on each unit's most recent five-year historical average of scheduled maintenance. The individual generating resource's forced outage assumptions are based on the resource's five-year historical NERC Generator Availability Database System ("GADS") equivalent forced outage rate data submitted to the ISO. If the resource has been in commercial operation less than five years, the NERC class average maintenance and forced outage data for the same class of units is used to substitute for the missing annual data.

The Qualified Capacity of an Intermittent Power Resource is the resource's median output during the Reliability Hours averaged over a period of five years. Based on the

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capacity ratings reflected in the Commission-approved Installed Capacity Requirements for the first ten primary FCAs. *See* 2019-2020 ICR Order at 15; 2018-2019 ICR Order at 7; 2017-2018 ICR Filing at 11-12 and 2017-2018 ICR Letter Order; 2016-2017 ICR Filing at 11-12; 2015-2016 ICR Filing at 11-12 and 2015-2016 ICR Order; 2014-2015 ICR Filing at 12-13 and 2014-2015 ICR Order at P 53; 2013-2014 ICR Filing at 10-11 and the 2013-2014 ICR Letter Order; 2012-2013 ICR Filing at 11-13 and the 2012-2013 ICR Letter Order; 2011-2012 ICR Filing at 11-12 and the 2011-2012 ICR Order at PP 1, 7; 2010-2011 ICR Filing at 11-12 and the 2010-2011 ICR Order at PP 1, 7.

[32] *ISO New England Inc.*, Informational Filing for Qualification in the Forward Capacity Market, filed on November 8, 2016 at Attachment C.

[33] Sedlacek-Scibelli Testimony at 10, 20.

[34] The assumed resource availability ratings for the 2020-2021 Capacity Commitment Period are discussed in the Sedlacek-Scibelli Testimony at 21-22. The ratings were calculated in accordance with Section III.12.7.3 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved Installed Capacity Requirements for the first ten primary FCAs. *See* note 12, *supra*.

Intermittent Power Resources rating methodology, these resources are assumed to be 100% available because their availability impacts on reliability are already incorporated into the resource ratings.

In the Installed Capacity Requirement calculations, performance assumptions for passive Demand Resources are modeled as 100% available. Active Demand Resources in the Real-Time Demand Response, and Real-Time Emergency Generator categories are based on actual responses during all historical ISO New England Operating Procedure No. 4 events (Action During a Capacity Deficiency) and ISO performance audits that occurred in summer and winter 2011 through 2015.

4. Tie Benefits

New England's Commission-approved method for establishing the Installed Capacity Requirement requires that assumptions be made regarding the tie benefits value to be used as an input in the calculation.[35] The tie benefits from neighboring Control Areas reflect the amount of emergency assistance from neighboring Control Areas that New England could rely on, without jeopardizing reliability in New England or the neighboring Control Areas, in the event of a capacity shortage in New England. Assuming tie benefits as a resource to meet the 0.1days/year LOLE criterion reduces the Installed Capacity Requirement and lowers the amount of capacity to be procured in the FCA.

The Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period proposed by the ISO reflects tie benefits calculated from the New Brunswick, New York and Quebec Control Areas.[36] The ISO utilizes a probabilistic multi-area reliability model to calculate total tie benefits from these three Control Areas. The neighboring Control Areas are modeled using "At Criteria" modeling assumptions. Tie benefits from each individual Control Area are determined based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas.

The tie benefits methodology is comprised of two broad steps. In step one, the ISO develops necessary system load, transmission interface transfer capabilities and capacity

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[35] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for the eleventh FCA is the same methodology used to calculate the tie benefits used in the Installed Capacity Requirement for Capacity Commitment Periods associated with prior FCAs.

[36] *See* 2014-2015 ICR Filing, Testimony at 25-35, for an explanation of the methodology employed by the ISO in determining tie benefits for the 2014-2015 Capacity Commitment Period, which was also employed by the ISO in determining tie benefits for the 2015-2016 Capacity Commitment Period, the 2016-2017 Capacity Commitment Period, the 2017-2018 Capacity Commitment Period, 2018-2019 Capacity Commitment Period, the 2019-2020 Capacity Commitment Period, and the 2020-2021 Capacity Commitment Period.

assumptions. In step two, the ISO conducts simulations using the probabilistic General Electric Multi-Area Reliability Simulation ("GE MARS") modeling program in order to determine tie benefits.

The Installed Capacity Requirement calculations for the 2020-2021 Capacity Commitment Period assume total tie benefits of 1,950 MW based on the results of the tie benefits study for the 2020-2021 Capacity Commitment Period. A breakdown of this total value by Control Area is as follows: 959 MW from Quebec over the Phase II interconnection, 145 MW from Quebec over the Highgate interconnection, 500 MW from New Brunswick (Maritimes) over the New Brunswick ties and 346 MW from New York over the AC ties.[37] The tie benefits methodology is described in detail in Section III.12.9 of the Tariff. These procedures were also addressed in detail in the transmittal letter for the 2014-2015 ICR Filing.[38]

Under Section III.12.9.2.4(a), one factor in the calculation of tie benefits is the transfer capability of the interconnections for which tie benefits are calculated. In the first half of 2016, the transfer limits of these external interconnections were reviewed based on the latest available information regarding forecasted topology and load forecast information, and it was determined that no changes to the established external interface limits were warranted. The ISO established transfer capability values for the following interconnections: 700 MW for the New Brunswick interconnections; 1,400 MW for the HQ Phase I/II HVDC Transmission Facilities; and 200 MW for the Highgate interconnection. The ISO also determined that there was no available transfer capability over the Cross Sound Cable for tie benefits. Finally, the ISO calculated a transfer capability for the New York-New England AC interconnections as a group, because the transfer capability of these interconnections is interdependent on the transfer capability of the other interconnections in the group. For the New York-New England AC interconnections, the transfer capability was determined to be 1,400 MW. The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.[39]

IV. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

In the FCM, the ISO must also calculate Local Sourcing Requirements and Maximum Capacity Limits. A Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone to meet the Installed Capacity

[37] Sedlacek-Scibelli Testimony at 27-28.

[38] 2014-2015 ICR Filing at 13-19.

[39] Sedlacek-Scibelli Testimony at 29-32.

Requirement.[40] A Maximum Capacity Limit is the maximum amount of capacity that must be electrically located in an export-constrained Capacity Zone to meet the Installed Capacity Requirement.[41] The general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to identify capacity resource needs such that, when considered in combination with the transfer capability of the transmission system, they are electrically distributed within the New England Control Area contributing toward purchasing the right amount of resources in the FCA to meet NPCC's and the ISO's bulk power system reliability planning criteria.

For the 2020-2021 Capacity Commitment Period, the ISO calculated the Local Sourcing Requirement for the SENE Capacity Zone using the methodology that is reflected in Section III.12.2 of the Tariff. The Local Sourcing Requirement for the SENE Capacity Zone is 9,810 MW.

The calculation methodology for determining Local Sourcing Requirements utilizes both Local Resource Adequacy criteria as well as criteria used in the Transmission Security Analysis that the ISO uses to maintain system reliability when reviewing de-list bids for a FCA. Because the system ultimately must meet both resource adequacy and transmission security requirements, the Local Sourcing Requirement provisions state that both resource adequacy and transmission security-based requirements must be developed for each import-constrained zone. Specifically, the Local Sourcing Requirement is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy Requirement or (ii) the Transmission Security Analysis Requirement.[42]

The Local Resource Adequacy Requirement is addressed in Section III.12.2.1.1 of the Tariff. It is a local zonal capacity requirement calculated using a probabilistic modeling technique that ensures the zone meets the one-day-in-ten years reliability standard. The Local Resource Adequacy Requirement analysis assumes the same set of resources used in the calculation of the Installed Capacity Requirement.

The calculation of the Transmission Security Analysis Requirement is addressed in Section III.12.2.1.2 of the Tariff, and the conditions used for completing the Transmission Security Analysis within the FCM are documented in Section 6 of ISO Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market ("PP-10").[43] The Transmission Security Analysis uses static transmission interface transfer limits, developed based on a series of discrete transmission load flow study scenarios, to evaluate the transmission import-constrained

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[40] *See* Section III.12.2 of the Tariff.

[41] *Id.*

[42] *See* Section III.12.2.1 of the Tariff.

[43] Copy available at https://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp10/pp10.pdf.

area's reliability. Using the analysis, the ISO identifies a resource requirement sufficient to allow the system to operate through stressed conditions.[44] The Transmission Security Analysis utilizes the same set of data underlying the load forecast, resource capacity ratings and resource availability that are used in calculating, probabilistically, the Installed Capacity Requirement, Maximum Capacity Limit and Local Resource Adequacy Requirement. However, due to the deterministic and transmission security oriented nature of the Transmission Security Analysis, some of the assumptions utilized in performing the Transmission Security Analysis differ from the assumptions used in calculating the Installed Capacity Requirement, Maximum Capacity Limit and other aspects of the Local Resource Adequacy Requirement. These differences relate to the manner in which load forecast data, forced outage rates for certain resource types, and ISO New England Operating Procedure No. 4 action events are utilized in the Transmission Security Analysis. These differences are described in more detail in the Sedlacek-Scibelli Testimony.[45]

The Local Resource Adequacy Requirement value and Transmission Security Analysis Requirement value for the SENE Capacity Zone calculated for the 2020-2021 Capacity Commitment Period are, respectively, 9,580 MW and 9,810 MW. Applying the "higher of" standard contained in Section III.12.2.1 of the Tariff, the resulting Local Sourcing Requirement value for the SENE Capacity Zone is 9,810 MW.

For the 2020-2021 Capacity Commitment Period, the ISO also calculated the Maximum Capacity Limit for the NNE Capacity Zone. The Maximum Capacity Limit was calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff. The Maximum Capacity Limit for the NNE Capacity Zone is 8,980 MW.

V. HQICCs

HQICCs are capacity credits that are allocated to the IRH, which are entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[46] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff,

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[44] *See* Section III.12.2.1.2(a) of the Tariff. The Transmission Security Analysis is similar, though not identical, to analysis that the ISO utilizes during the reliability review of de-list bids. *See ISO New England Inc.*, 123 FERC ¶ 61,290 at PP 26-31 (2008).

[45] Sedlacek-Scibelli Testimony at 38-39.

[46] *See* Section I.2.2 of the Tariff (stating in the definition of "Hydro-Quebec Interconnection Capability Credit" that "[a]n 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."). *See also* Section III.12.9.7 of the Tariff ("[t]he tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.").

the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to the IRH in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each Capacity Commitment Period's FCA. The HQICC value for the 2020-2021 Capacity Commitment Period is 959 MW per month.

VI. MRI DEMAND CURVES

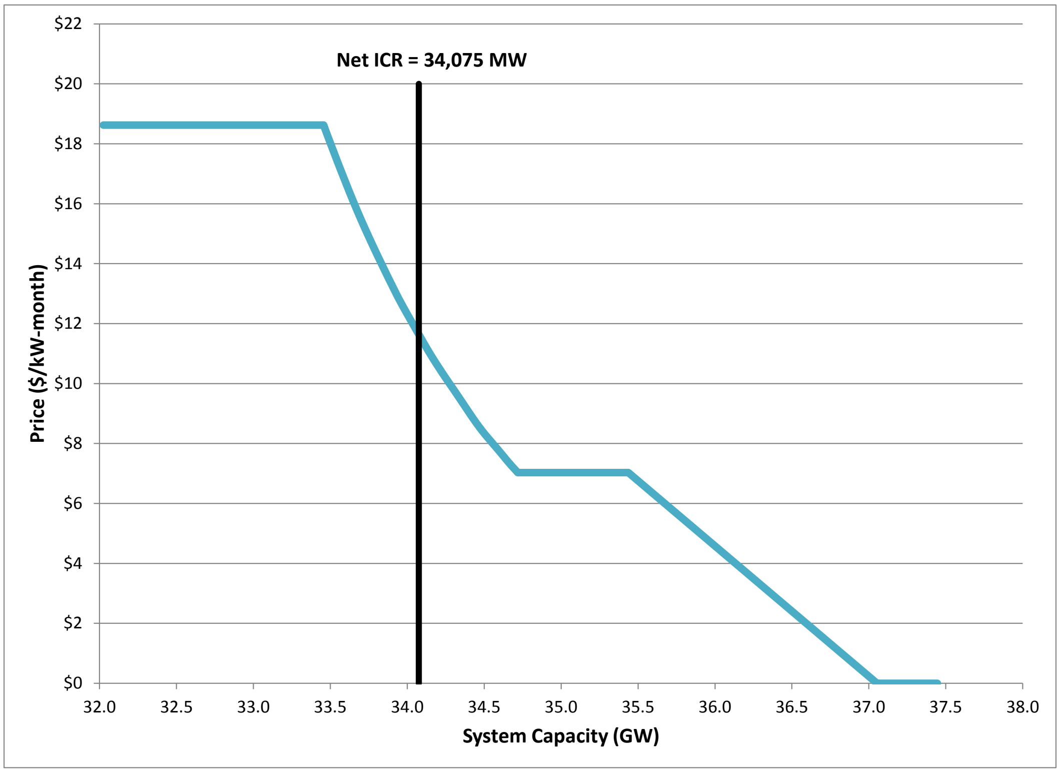
In December 2015, FERC required the ISO to implement, beginning with the eleventh FCA, sloped demand curves in the FCM. The ISO submitted the MRI Demand Curve design filing on April 15, 2016, and the Commission accepted the ISO's filing on June 28, 2016.[47] Accordingly, starting with the eleventh FCA, using the MRI Demand Curve methodology, the ISO is required to develop system-wide and zonal sloped demand curves to be used in the FCA to procure needed capacity.

A. System-Wide Capacity Demand Curve

Under Section III.12.1.1 of the Tariff, prior to each FCA, the ISO must determine the system-wide MRI of capacity at various higher and lower capacity levels for the New England Control Area. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement. Using the values calculated pursuant to Section III.12.1.1.1, the ISO must determine the System-Wide Capacity Demand Curve pursuant to Section III.13.2.2.1 of the Tariff. Note that, for this year, the ISO used the transition provisions in Section III.13.2.2.1 to determine the System-Wide Demand Curve. The transition curve is a hybrid of the previous linear demand curve design and the new MRI-based design. The following is the System-Wide Capacity Demand Curve for the eleventh FCA:[48]

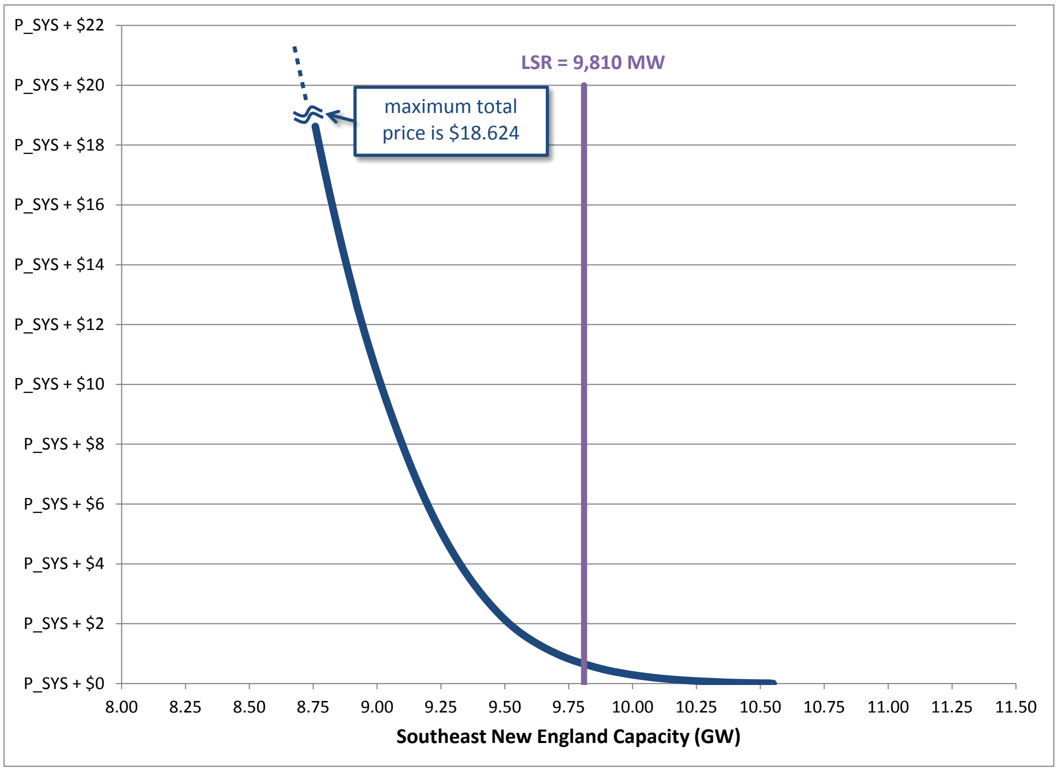
[47] *See* note 11, *supra*.

[48] Additional details regarding the calculation of the System-Wide Capacity Demand Curve are included in the Sedlacek-Scibelli Testimony at 43-47.



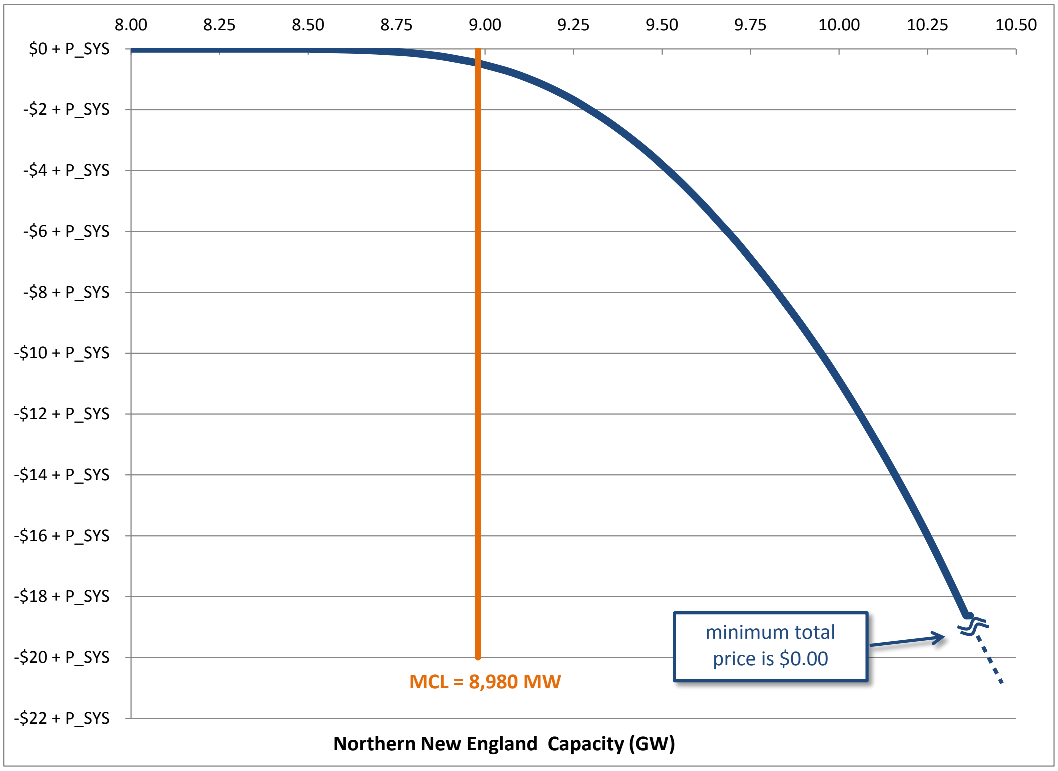
B. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone

Under Section III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels, for each import-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) has to be reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero. Using the values calculated pursuant to Section III.12.2.1.3 of the Tariff, the ISO must determine the Import-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.2 of the Tariff. For the eleventh FCA, the only import-constrained Capacity Zone is SENE and, therefore, there is only one Import-Constrained Capacity Zone Demand Curve. The following is the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for the eleventh FCA:



C. Export-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone

Under Section III.12.2.2.1 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels, for each export-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the Export-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For the eleventh FCA, the only export-constrained Capacity Zone is NNE and, therefore, there is only one Export-Constrained Capacity Zone Demand Curve. The following is the Export-Constrained Capacity Zone Demand Curve for NNE for the eleventh FCA:



VII. STAKEHOLDER PROCESS

As in past years, the ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR-Related Values for the 2020-2021 Capacity Commitment Period through an extensive stakeholder process over the course of seven months. This process included review by NEPOOL's Power Supply Planning Committee ("PSPC") during the course of four meetings.[49] In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[50] Among other responsibilities, NESCOE is responsible for providing feedback on the proposed ICR-Related Values at the relevant NEPOOL PSPC, Reliability Committee and Participants Committee meetings, and was in attendance for the

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[49] All of the load and resource assumptions needed for the General Electric Multi-Area Simulation ("GE MARS") model used to calculate tie benefits and the ICR-Related Values were reviewed by the PSPC, a subcommittee of the NEPOOL Reliability Committee.

[50] *ISO New England Inc.*, Docket No. ER07-1324-000, Formation of the New England States Committee on Electricity (filed August 31, 2007) (proposing to add a new rate schedule to the Tariff for the purpose of recovering funding for NESCOE's operation) (the "NESCOE Funding Filing"); *ISO New England Inc.*, 121 FERC ¶ 61,105 (2007) (order accepting the ISO's proposed rate schedule for funding of NESCOE's operations).

meetings at which the ICR-Related Values for the 2020-2021 Capacity Commitment Period were discussed.[51]

On September 20, 2016, the Reliability Committee voted to recommend, by a show of hands (with two oppositions and two abstentions) that the Participants Committee support the HQICCs. On October 4, 2016, the Reliability Committee voted to recommend, by a show of hands (with one opposition and two abstentions), that the Participants Committee support the Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, and the MRI Demand Curves. On October 14, 2016, the Participants Committee supported the HQICCs as well as the Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, Maximum Capacity Limit for the NNE Capacity Zone, and the MRI Demand Curves (with oppositions and abstentions noted).

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for the 2020-2021 Capacity Commitment Period to be effective on January 7, 2017 (which is 60 days from the filing date), so that the proposed values can be used as part of the eleventh FCA to be conducted in February 2017.

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for the 2020-2021 Capacity Commitment Period and is made pursuant to Section 205 of the FPA. Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of cost-of-service rates.[52] However, the proposed ICR-Related Values are not traditional "rates." Furthermore, the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the ISO requests waiver of Section 35.13 of the Commission's regulations. Notwithstanding its request for waiver, the ISO submits the following additional information in compliance with the identified filing regulations of the Commission applicable to Section 205 filings.

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

- This transmittal letter;
- Attachment 1: Joint Testimony of Carissa Sedlacek and Maria Scibelli;
- Attachment 2: List of governors and utility regulatory agencies in

[51] *See* the NESCOE Funding Filing at 14.

[52] 18 C.F.R. § 35.13.

Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been emailed.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 7, 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 https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. An electronic copy of this transmittal letter and the accompanying materials has also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 2. In accordance with Commission rules and practice, here is no need for the entities identified on Attachment 2 to be included on the Commission's official service list in the captioned proceedings 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 this transmittal letter.

35.13(b)(5) - The reasons for this filing are discussed in Sections III-VI of this transmittal letter.

35.13(b)(6) - As explained above, the ISO has sought the advisory input from Governance Participants pursuant to Section 11.4 of the Participants Agreement.

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

35.13(c)(2) - The ISO does not provide services under other rate schedules that are similar to the sale for 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 order to supply service with respect to the proposed Installed Capacity Requirement and related values.

X. CONCLUSION

The Filing Parties request that the Commission accept the proposed ICR-Related Values reflected in this submission for filing without change to become effective January 7, 2017.

Respectfully submitted,

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NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

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Attachments
cc : Entities listed in Attachment 2

Attachment 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. **)** **Docket No. ER17-___-000**

PREPARED TESTIMONY OF
MS. CARISSA SEDLACEK and MS. MARIA SCIBELLI
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: **Ms. Sedlacek:** My name is Carissa Sedlacek. I am the Director of Resource Adequacy in the System Planning Department at ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Ms. Scibelli: My name is Maria Scibelli. I am Principal Analyst, Resource Adequacy in the System Planning Department at the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: MS. SEDLACEK, PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: In 2015, I was promoted to Director of Resource Adequacy in the System Planning Department at the ISO. In this position, I have overall responsibility for operation of the Forward Capacity Market ("FCM"), including the development of the Installed Capacity Requirement for all auctions; the resource qualification processes for new and existing resources; the conduct of the critical path schedule monitoring process for new resources; and the performance of reliability reviews for resources seeking to opt out of the market.

In addition, I have the responsibility for conducting resource adequacy/reliability assessments to meet North American Electric Reliability Corporation ("NERC") and Northeast Power Coordinating Council ("NPCC") reporting requirements, long-term load forecast development, fuel diversity analyses, and resource mix evaluations to ensure regional bulk power system reliability into the future.

Before becoming Director of Resource Adequacy, I was Manager, Resource Integration & Analysis in the System Planning Department at the ISO. In that role I was responsible for implementing the FCM qualification process for Generating Capacity Resources, Demand Resources, and Import Capacity Resources; for analyzing de-list bids; and for developing market resource alternatives as a substitute to building new transmission facilities. Prior to that, between 1999 and 2006, I led various generation planning and availability studies to ensure system reliability as well as transmission planning assessments related to transmission facility construction, system protection, and line ratings. I have published in the IEEE Power Engineering Review for analysis of Generator Availabilities under a Market Environment. I have been with the ISO since 1999, working in the System Planning Department.

Prior to joining the ISO, I worked at the New York Power Authority's Niagara Power Project for eleven years providing engineering support to ensure the reliable operation of the 2,500 MW hydroelectric facility and its associated transmission system.

I have a B.S. in Electrical Engineering from Syracuse University and a M.B.A. from State University of New York at Buffalo.

Q: MS. SCIBELLI, PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I hold a Bachelor of Science degree in Chemistry from Western New England University. I have over 30 years of electric industry experience with over 20 years at the ISO and its planning department predecessor New England Power Planning ("NEPLAN") and prior to that at Northeast Utilities (now Eversource Energy).

I am currently the Chair of the New England Power Pool ("NEPOOL") Power Supply Planning Committee ("PSPC"), the NEPOOL technical committee that assists the ISO in the review and development of all assumptions used for the calculation and development of Installed Capacity Requirements, Local Sourcing Requirements, Transmission Security Analysis Requirements, Local Resource Adequacy Requirements, Maximum Capacity Limits and demand curves. Prior to becoming Chair, I was the secretary of the PSPC for nine years.

Since 2006, I have worked in the Resource Adequacy group in the ISO's System Planning Department, where I have been the ISO's lead for the calculation of the Installed Capacity Requirement and associated values, including the development of the assumptions used in the calculations. I am responsible for discussion and review of the Installed Capacity Requirement and associated values at the PSPC and NEPOOL

Reliability Committee. In addition, I am the author of the annual report of Installed Capacity Requirement and associated values which details the methodology, assumptions and results that comprises each Capacity Commitment Period's Installed Capacity Requirement's study. I also provide support in the development of the Regional System Plans and other resource adequacy studies.

Q: WHAT IS THE PURPOSE OF THIS TESTIMONY?

A: This testimony discusses the derivation of the Installed Capacity Requirement, the Local Sourcing Requirement for the Southeastern New England ("SENE") Capacity Zone, the Maximum Capacity Limit for the Northern New England ("NNE") Capacity Zone,[1] the Hydro-Quebec Interconnection Capability Credits ("HQICCs"), and the Marginal Reliability Impact ("MRI") Demand Curves for the 2020-2021 Capacity Commitment Period, which is the Capacity Commitment Period associated with the eleventh Forward Capacity Auction ("FCA") to be conducted in February 2017. The 2020-2021 Capacity Commitment Period starts on June 1, 2020 and ends on May 31, 2021. The Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone,

[1] As explained in the ISO's Informational Filing for the eleventh FCA, which is being submitted to the Commission concurrently with this filing, in accordance with Section III.12.4. of the Tariff, the ISO determined that it will model three Capacity Zones in the eleventh FCA: the SENE Capacity Zone, the NNE Capacity Zone, and the Rest of Pool Capacity Zone. The SENE Capacity Zone includes Southeastern Massachusetts, Rhode Island and Northeastern Massachusetts/Boston Load Zones. The SENE Capacity Zone will be modeled as an import-constrained Capacity Zone. The NNE Capacity Zone includes Maine, New Hampshire, and Vermont Load Zones. NNE will be modeled as an export-constrained Capacity Zone. The Rest of Pool Capacity Zone includes Connecticut and Western/Central Massachusetts Load Zones.

Maximum Capacity Limit for the NNE Capacity Zone, HQICCs and MRI Demand Curves are collectively referred to herein as the "ICR-Related Values."

Q. ARE THERE ANY CHANGES TO THE PROCESS AND METHODOLOGY FOR DEVELOPING THE INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES?

A. This year, there are two changes in the process and methodology for developing the ICR-Related Values.

First, MRI system-wide and zonal demand curves will be used for the first time to procure capacity in the FCM for the 2020-2021 Capacity Commitment Period.[2] Specifically, the new MRI Demand Curve methodology[3] is being used to calculate: (1) the System-Wide Capacity Demand Curve; (2) the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone; and (3) the Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone.

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[2] System-wide capacity demand curves were developed for the ninth and tenth FCAs using a linear methodology.

[3] The ISO filed the Demand Curve Design Improvements with the Commission in Docket No. ER16-1434-000 on April 15, 2016. The Commission accepted the Demand Curve Design Improvements in an Order dated June 28, 2016. *ISO New England Inc. and New England Power Pool Participants Committee*, 155 FERC ¶ 61,319 (2016).

Second, there is a slight change in the methodology used to reflect the photovoltaic ("PV") forecast[4] as a deduction in the load forecast, which is one of the assumptions used in the calculations of the ICR-Related Values.

The process and methodology for developing all the other ICR-Related Values for the 2020-2021 Capacity Commitment Period are the same as those used in the calculation of the ICR-Related Values for the 2019-2020 Capacity Commitment Period.

II. INSTALLED CAPACITY REQUIREMENT

A. DESCRIPTION OF THE INSTALLED CAPACITY REQUIREMENT

Q: WHAT IS THE "INSTALLED CAPACITY REQUIREMENT?"

A: The Installed Capacity Requirement is the minimum level of capacity required to meet the reliability requirements defined for the New England Control Area. This requirement is documented in Section 2 of ISO New England Planning Procedure No. 3, Reliability Standards for the New England Area Bulk Power Supply System, which states:

> **Resources** will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting noninterruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting noninterruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year.
>
> a. The possibility that load forecasts may be exceeded as a result of weather variations.

[4] Starting in 2014, the ISO has developed an annual PV forecast for the region.

b. Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.

c. Due allowance for scheduled outages and deratings.

d. Seasonal adjustment of resource capability.

e. Proper maintenance requirements.

f. Available operating procedures.

g. The reliability benefits of interconnections with systems that are not Governance Participants.

h. Such other factors as may from time-to-time be appropriate.[5]

Q: PLEASE EXPLAIN THE GENERAL PROCESS FOR ESTABLISHING THE ICR-RELATED VALUES.

A: The ICR-Related Values for the 2020-2021 Capacity Commitment Period were established through a stakeholder process and in accordance with the calculation methodology prescribed in Section III.12 of the Tariff. The stakeholder process consisted of discussions with the NEPOOL Load Forecast Committee, the PSPC and the NEPOOL Reliability Committee. These committees' review and comment on the ISO's development of load and resource assumptions and the ISO's calculation of the ICR-Related Values for the 2020-2021 Capacity Commitment Period was followed by advisory votes from the NEPOOL Reliability Committee and NEPOOL Participants Committee. State regulators also had the opportunity to review and comment on the ICR-Related Values as part of their participation on the PSPC, Reliability Committee and Participants Committee. The NEPOOL Participants Committee supported the ICR-Related Values. The ISO is filing with the Commission the ICR-Related Values for the

[5] Copy available athttps://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf.

2020-2021 Capacity Commitment Period.

Q: PLEASE EXPLAIN IN MORE DETAIL THE PSPC'S INVOLVEMENT IN THE DETERMINATION AND REVIEW OF THE ICR-RELATED VALUES.

A: The PSPC is a non-voting technical subcommittee under the Reliability Committee. The PSPC is chaired by the ISO and its members are representatives of the NEPOOL Participants. The ISO engages the PSPC to assist with the review of key inputs used in the development of resource adequacy-based requirements such as the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and MRI Demand Curves, including appropriate assumptions relating to load, resources, and tie benefits for modeling the expected system conditions. Representatives of the six New England States' public utilities regulatory commissions are also invited to attend and participate in the PSPC meetings and several were present for the meetings at which the ICR-Related Values for the 2020-2021 Capacity Commitment Period were discussed and considered.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE CALCULATED BY THE ISO FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: The Installed Capacity Requirement value for the 2020-2021 Capacity Commitment Period is 35,034 MW.

Q: IS THIS THE AMOUNT OF INSTALLED CAPACITY REQUIREMENT THAT WAS USED FOR THE DEVELOPMENT OF THE MRI DEMAND CURVES FOR THE ELEVENTH FCA?

A: No. The MRI Demand Curves were developed based on the net Installed Capacity Requirement of 34,075 MW, which is the 35,034 MW of Installed Capacity Requirement minus 959 MW of HQICCs that are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of the Tariff.

B. DEVELOPMENT OF THE INSTALLED CAPACITY REQUIREMENT

Q: PLEASE EXPLAIN THE CALCULATION METHODOLOGY FOR ESTABLISHING THE INSTALLED CAPACITY REQUIREMENT.

A: The Installed Capacity Requirement was established using the General Electric Multi-Area Reliability Simulation ("GE MARS") model. GE MARS uses a sequential Monte Carlo simulation to compute the resource adequacy of a power system. This Monte Carlo process repeatedly simulates the year (multiple replications) to evaluate the impacts of a wide range of possible combinations of resource capacity and load levels taking into account random resource outages. For the Installed Capacity Requirement, the system is considered to be a one bus model, in that the New England transmission system is assumed to have no internal transmission constraints in this simulation. For each hour, the program computes the isolated area capacity available to meet demand based on the expected maintenance and forced outages of the resources and the expected demand. Based on the available capacity, the program determines the probability of loss of load for the system for each hour of the year. After simulating all hours of the year, the program sums the probability of loss of load for each hour to arrive at an annual probability of loss of load value. This value is tested for convergence, which is set to be 5% of the standard deviation of the average of the hourly loss of load values. If the simulation has not converged, it proceeds to another replication of the study year. Once the program has computed an annual reliability index, if the system is less reliable than the resource-adequacy criterion (*i.e.*, the system loss of load expectation ("LOLE") is greater than 0.1 days per year), additional resources are needed to meet the criterion. Under the condition where New England is forecasted to be less reliable than the resource adequacy criterion, proxy resources are used within the model to meet this additional need. The methodology calls for adding proxy units until the New England LOLE is less than 0.1 days per year. For the ICR-Related Values for the 2020-2021 Capacity Commitment Period, the ISO did not need to use proxy units because there is adequate qualified capacity to meet the 0.1 days/year LOLE criterion.

If the system is more reliable than the resource-adequacy criterion (*i.e.*, the system LOLE is less than or equal to 0.1 days per year), additional resources are not required, and the Installed Capacity Requirement is determined by increasing loads (additional load carrying capability or "ALCC") so that New England's LOLE is exactly at 0.1 days per year. This is how the single value that is called the Installed Capacity Requirement is established. The modeled New England system must meet the 0.1 days per year reliability criterion.

Q: WHAT ARE THE MAIN ASSUMPTIONS UPON WHICH THE ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD ARE BASED?

A: One of the first steps in the process of determining the ICR-Related Values is for the ISO to identify reasonable assumptions relating to expected system conditions for the Capacity Commitment Period. These assumptions are explained in detail below and include the load forecast, resource capacity ratings, resource availability, and the amount of load and/or capacity relief obtainable from certain actions specified in ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency ("Operating Procedure No. 4"), which system operators invoke in real time to balance demand with system supply in the event of expected capacity shortage conditions. Relief available from Operating Procedure No. 4 actions includes the amount of possible emergency assistance (tie benefits) obtainable from New England's interconnections with neighboring Control Areas and load reduction from implementation of 5% voltage reductions.

1. LOAD FORECAST

Q: PLEASE EXPLAIN HOW THE ISO DERIVED THE LOAD FORECAST ASSUMPTION USED IN DEVELOPING THE ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: For probabilistic-based calculations of ICR-Related Values, the ISO develops a forecasted distribution of typical daily peak loads for each week of the year based on 40 years of historical weather data and an econometrically estimated monthly model of typical daily peak loads. Each weekly distribution of typical daily peak loads includes the full range of daily peaks that could occur over the full range of weather experienced in that week and their associated probabilities. The 50/50 and the 90/10 peak loads are points on this distribution and used as reference points. The probabilistic-based calculations take into account all possible forecast load levels for the year. From these weekly peak load forecast distributions, a set of seasonal load forecast uncertainty multipliers can be developed and applied to a specific historical hourly load profile to provide seasonal load information about the probability of loads being higher, and lower, than the peak load found in the historical profile. These multipliers can be developed for New England in its entirety or for each subarea using the historic 2002 load profile.

Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN CAPACITY ZONES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: The forecasted load for the SENE Capacity Zone was developed using the combined load forecast for the state of Rhode Island and a load share ratio of the Southeastern Massachusetts ("SEMA") and Northeastern Massachusetts ("NEMA")/Boston load to the forecasted load for the entire Commonwealth of Massachusetts. The load share ratio is based on detailed bus load data from the network model for SEMA and NEMA/Boston, respectively, as compared to all of Massachusetts.

The forecasted load for the NNE Capacity Zone was developed using the combined load forecasts for the states of Maine, New Hampshire, and Vermont.

Q: PLEASE DESCRIBE THE PROJECTED NEW ENGLAND AND CAPACITY ZONE 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: The following table shows the 50/50 and 90/10 peak load forecast for the 2020-2021 Capacity Commitment Period based on the 2016 load forecast as documented in the 2016 – 2025 Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT") Report.

Table 1 – 50/50 and 90/10 Peak Load Forecast (MW)

	50/50	90/10
New England	29,601	32,081
SENE	12,153	13,190
NNE	5,882	6,305

Q: PLEASE DESCRIBE HOW THE PV FORECAST IS ACCOUNTED FOR IN THE CALCUALTIONS OF THE ICR-RELATED VALUES.

A: The calculations of the ICR-Related Values reflect the load reduction impact of behind-the-meter ("BTM") PV facilities. These are in-service behind-the-meter PV facilities and behind-the-meter PV facilities that are forecasted to be installed prior to the Capacity Commitment Period of interest. In order to determine the load reduction impact of the BTM PV facilities, the ISO used coincident hourly load and PV production data for the years 2012-2015. The ISO derived some of this data from publically available data sources, and distribution utilities also provided data. The ISO calculated the PV value for the net load scenario for 2020-2021 and then adjusted the load forecast by this forecasted BTM PV.

Q: ARE THERE ANY CHANGES TO THE METHODOLOGY THAT WAS USED TO REFLECT THE PV FORECAST IN THE CALCULATION OF THE ICR-RELATED VALUES FOR THE PREVIOUS CAPACITY COMMITMENT PERIOD?

A: Yes. In order to reflect the PV forecast in the calculation of the ICR-Related Values for the 2020-2021 Capacity Commitment Period, the ISO categorized PV facilities into three types: (1) PV resources that participate as resources in the FCM and that are modeled for the Capacity Commitment Period of interest if they qualify to participate in that Capacity Commitment Period; (2) PV resources that do not participate in the FCM but participate in the energy market as Settlement Only Resources ("SORs"); and (3) the BTM PV which reduce system load and are not part of any ISO market. The system load reduction associated with the BTM PV is reflected in the load forecast which is used to calculate the ICR-Related Values for the 2020-2021 Capacity Commitment Period. For the 2019-202 Capacity Commitment Period calculations, BTM PV was further subdivided into two subcategories, behind-the-meter PV embedded in load ("BTMEL") and behind-the-meter PV not embedded in load ("BTMNEL"). Unlike last year, in the 2016 PV forecast, full reconstitution of PV output in both of these subcategories was taken into account in the historical loads used to develop the long-term load forecast. This allowed the ISO to combine these two subcategories into one category, *i.e.* the BTM PV.

Q: PLEASE EXPLAIN THE METHODOLOGY USED TO DEVELOP THE PV FORECAST AND HOW IT IS REFLECTED IN THE ICR-RELATED VALUES.

A: Annually, the ISO, in conjunction with the Distributed Generation Forecast Working Group ("DGFWG") (which includes state agencies responsible for administering the New England states' policies, incentive programs and tax credits that support PV growth in New England), develops forecasts of future nameplate ratings of PV installations anticipated over the 10-year planning horizon. These forecasts are created for each state based on policy drivers, recent PV growth trends, and discount adjustments designed to represent a degree of uncertainty in future PV commercialization.

In order to estimate the expected output from these future installations during summer peak load conditions, the ISO used publically available state PV profiles from four years of historical data (2012-2015). These were developed from production data available from more than 1,200 currently installed individual PV sites throughout New England. These profiles were used as the basis for an Estimated Summer Seasonal Peak Load Reduction value (% of BTM nameplate rating) of 36.1% for the 2020-2021 Capacity Commitment Period. The percent of the BTM PV nameplate values reflect the load reduction capability of the BTM PV resources at the time of the peaks.

In addition, since the 2016 PV forecast represents end-of-year forecast values, a monthly value representing incremental growth throughout the year was determined by using PV growth trends across the region over the past three years. These values were applied to the annual end-of-year PV forecast values over the forecast horizon to develop the appropriate monthly values.

The monthly values of the PV forecast for the 2020-2021 Capacity Commitment Period shown in Table 2 below are modeled as a load modifier in the GE MARS model within the probabilistic calculations for the ICR-Related Values. These values are distributed to sub-areas for the summer reliability hours ending 14:00 through 18:00. All other hours and all non-summer months are considered as zeros. For deterministic analyses, the reference load forecast which is net of BTM PV resources was used. Modeling the PV resources this way effectively reduced the load forecast for each month by the corresponding monthly PV forecast values.

Table 2 – Monthly Value of BTM PV for 2020-2021 (MW)[6]

Month	2020-2021
Jun	672
Jul	676
Aug	680
Sep	684
Oct	0
Nov	0
Dec	0
Jan	0
Feb	0
Mar	0
Apr	0
May	709

[6] The values shown include the 8% Transmission and Distribution gross-up given to resources at the load bus to bring them to the generator bus level where New England load is calculated.

The BTM PV reduction to the load forecast resulted in a 720 MW reduction in the Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: The ICR-Related Values for the 2020-2021 Capacity Commitment Period were developed based on the Existing Qualified Capacity Resources for the 2020-2021 Capacity Commitment Period. This assumption is based on the latest available data at the time of the ICR-Related Values calculation.

Q: WHAT ARE THE RESOURCE CAPACITY VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD?

A: The following tables show the make-up of the 34,389 MW of capacity resources assumed in the calculation of the ICR-Related Values.

Table 3**– Qualified Existing Non-Intermittent Generating Capacity Resources by Load Zone (MW)**[7]

Load Zone	Summer
MAINE	2,949.645
NEW HAMPSHIRE	4,075.922
VERMONT	218.351
CONNECTICUT	9,655.575
RHODE ISLAND	2,360.257
SOUTH EAST MASSACHUSETTS	4,357.821
WEST CENTRAL MASSACHUSETTS	3,739.406
NORTH EAST MASSACHUSETTS & BOSTON	3,211.668
Total New England	**30,568.645**

[7] A 30 MW derate is applied to resources located in the Vermont Load Zone to reflect the value of the firm Vermont Joint Owners contract.

Table 4– Qualified Existing Intermittent Power Resources by Load Zone (MW)[8]

Load Zone	Summer	Winter
MAINE	217.875	338.053
NEW HAMPSHIRE	162.576	229.151
VERMONT	74.693	124.751
CONNECTICUT	166.590	180.804
RHODE ISLAND	9.261	18.088
SOUTH EAST MASSACHUSETTS	95.076	78.189
WEST CENTRAL MASSACHUSETTS	103.052	120.676
NORTH EAST MASSACHUSETTS & BOSTON	77.056	72.834
Total New England	**906.179**	**1,162.546**

Table 5– Qualified Existing Import Capacity Resources (MW)

Import Resource	Summer	External Interface
VJO - Highgate	6.000	Hydro-Quebec Highgate
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total	88.800	

Also modeled was one Administrative Export (known sale) of 100 MW to the Long Island Power Authority ("LIPA") over the Cross Sound Cable direct current ("DC") interface.

Table 6 – Qualified Administrative Exports (Known Sales (MW))

Export	Summer
LIPA over Cross Sound Cable	(100.000)

[8] All resources have only their summer capacity rating modeled in the ICR-Related Values with the exception of Intermittent Power Resources which have both their summer and winter capacity ratings modeled.

Table 7– Qualified Existing Demand Resources by Load Zone (Summer MW)

Load Zone	On-Peak	Seasonal Peak	Real-Time Demand Response	Real-Time Emergency Generators	Total
MAINE	136.992	-	136.536	6.402	279.930
NEW HAMPSHIRE	106.299	-	10.067	12.300	128.666
VERMONT	93.335	-	30.399	5.458	129.192
CONNECTICUT	75.583	440.158	59.426	59.097	634.264
RHODE ISLAND	207.499	-	35.944	15.720	259.163
SOUTH EAST MASSACHUSETTS	311.925	-	46.340	12.722	370.987
WEST CENTRAL MASSACHUSETTS	343.751	45.251	47.145	25.530	461.677
NORTH EAST MASSACHUSETTS & BOSTON	590.347	-	62.097	9.430	661.874
Total New England	1,865.731	485.409	427.954	146.659	2,925.753

Although capacity resource data are tabulated under the eight settlement Load Zones, only SENE (the combined NEMA/Boston, SEMA and Rhode Island Load Zones) and NNE (the combined Maine, New Hampshire and Vermont Load Zones) are relevant for the eleventh FCA.

Q: WHAT ARE THE ASSUMPTIONS RELATING TO RESOURCE ADDITIONS (THOSE WITHOUT CAPACITY SUPPLY OBLIGATIONS) AND ATTRITIONS?

A: Resource additions, beyond those classified as "Existing Capacity Resources," and attritions (associated with bids to de-list resources or retirements) are not assumed in the calculation of the ICR-Related Values for the 2020-2021 Capacity Commitment Period because there is no certainty that new resource additions or resource attritions will clear the auction.

3. RESOURCE AVAILABILITY

Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS UNDERLYING THE CALCULATIONS OF THE ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: Resources are modeled at Qualified Capacity values and resource availability is also considered in the calculation of the ICR-Related Values. For generating resources, scheduled maintenance assumptions are based on each unit's historical five-year average of scheduled maintenance. If the individual resource has not been operational for a total of five years, then NERC class average data is used to substitute for the missing annual data. It is assumed that maintenance outages of generating resources will not be scheduled during the peak load season of June through August. An individual generating resource's forced outage assumption is based on the resource's five-year historical data from the ISO's database of NERC Generator Availability Database System ("GADS"). If the individual resource has not been operational for a total of five years, then NERC class average data is used. As stated earlier, the same resource availability assumptions are used in all the calculations except for the Transmission Security Analysis, which requires the modeling of the start-up availability of the fast-start (*i.e.* peaking) resources to reflect their performance when dispatched.

The Qualified Capacity of an Intermittent Power Resource is based on the resource's historical median output during the Reliability Hours averaged over a period of five years. The Reliability Hours are specific, defined hours during the summer and the winter, and hours during the year in which the ISO has declared a system-wide or a Load Zone-specific shortage event. Because this method already takes into account the resource's availability, Intermittent Power Resources are assumed to be 100% available in the models at their "Qualified Capacity" and not based on "nameplate" ratings. Qualified Capacity is the amount of capacity that either a generating, demand, or import resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the FCM qualification process.

Performance of Demand Resources in the Real-Time Demand Response and Real-Time Emergency Generator categories is measured by actual response during performance audits and Operating Procedure No. 4 events that occurred in the summer and winter of the most recent five-year period, currently 2011 through 2015. To calculate historical availability, the verified commercial capacity of each resource is compared to its monthly net Capacity Supply Obligation. Demand Resources in the On-Peak Demand and Seasonal Peak Demand categories are non-dispatchable resources that reduce load across pre-defined hours, typically by means of energy efficiency. These types of Demand Resources are assumed 100% available.

4. OTHER ASSUMPTIONS

Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: The assumed N-1 and N-1-1 transmission import transfer capability of the Southeast New England Import interface used to calculate the SENE Capacity Zone Local Sourcing Requirement and N-1 transmission export transfer capability of the North-South interface used to calculate the NNE Capacity Zone Maximum Capacity Limit are shown in the table below.

Table 8 – Internal Transmission Import Capabilities (MW)

Interface		2020/21
Southeast New England Import (for SENE LSR)	N-1	5,700
	N-1-1	4,600
North-South (for NNE MCL)	N-1	2,725

Q: PLEASE DISCUSS THE ISO'S ASSUMPTIONS REGARDING THE ACTIONS OF OPERATING PROCEDURE NO. 4 IN DEVELOPING THE ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: In the development of the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit and MRI Demand Curves, assumed emergency assistance (*i.e.* tie benefits, which are described below) available from neighboring Control Areas, load reduction from implementation of 5% voltage reductions, and capacity available from dispatch of Real-Time Emergency Generation are used. These all constitute actions that system operators invoke under Operating Procedure No. 4 in real time to balance system demand with supply under expected or actual capacity shortage conditions. The amount of load relief assumed obtainable from invoking 5% voltage reductions is based on the performance standard established in ISO New England Operating Procedure No. 13, Standards for Voltage Reduction and Load Shedding Capability ("Operating Procedure No. 13").[9] Operating Procedure No. 13 requires that "…each Market Participant with control over transmission/distribution facilities must have the capability to reduce system load demand, at the time a voltage reduction is initiated, by at least one and one-half (1.5) percent through implementation of a voltage reduction." Using the 1.5% reduction in system load demand, the assumed voltage reduction load relief values, which offset against the Installed Capacity Requirement, are 437 MW for June through September 2020 and 325 MW for October 2020 through May 2021.

Real-Time Emergency Generation Resources are available for dispatch under expected Operating Procedure No 4 conditions. There are 147 MW of these capacity resources, with an expected availability factor calculated as previously described, modeled in the development of the ICR-Related Values.[10]

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[9] Copy available at: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op13/op13_rto_final.pdf.

[10] The ISO has taken steps to address the reversal of the Environmental Protection Agency's ("EPA") rules that allowed Real-Time Emergency Generation Resources to operate for purposes of emergency demand response. *See* ISO New England Inc., Filing of Request for Limited Waiver, Docket No. ER16-1904-000 (June 9, 2016), granted by the Commission on August 8, 2016 in *ISO New England Inc.*, 156 FERC ¶ 61,096 (2016). However, due to the timing of the qualification for existing resources, which

5. TIE BENEFITS

Q: WHAT ARE TIE BENEFITS?

A: Tie benefits represent the possible emergency energy assistance from the interconnected neighboring Control Areas when a capacity shortage occurs.

Q: WHAT IS THE ROLE OF EXTERNAL TRANSMISSION IMPORT TRANSFER CAPABILITIES IN DEVELOPING THE ICR-RELATED VALUES?

A: While external transmission import transfer capabilities are not an input to the calculation of the ICR-Related Values, they do impact the tie benefit assumption. Specifically, the external transmission import transfer capabilities would impact the amount of emergency energy, if available, that could be imported into New England.

Q: ARE INTERNAL TRANSMISSION TRANSFER CAPABILITIES MODELED IN TIE BENEFITS STUDIES?

A: Internal transmission transfer capability constraints that are not addressed by either a Local Sourcing Requirement or Maximum Capacity Limit are modeled in the tie benefits study. The results of the tie benefits study are used as an input in the Installed Capacity

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occurred before the District of Columbia Circuit and the EPA issued its ruling and memorandum, respectively, as well as the timing of the calculation of the ICR-Related Values, the ISO modeled 147 MW of Real-Time Emergency Generation Resources, with appropriate outage assumptions, in the ICR-Related Values for the 2020-2021 Capacity Commitment Period. This MW amount will be reduced for future FCAs.

Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit, and MRI Demand Curves calculations.

Q: PLEASE EXPLAIN HOW TIE BENEFITS FROM NEIGHBORING CONTROL AREAS ARE ACCOUNTED FOR IN DETERMINING THE INSTALLED CAPACITY REQUIREMENT.

A: The New England resource planning reliability criterion requires that adequate capacity resources be planned and installed such that disconnection of firm load would not occur more often than once in ten years due to a capacity deficiency after taking into account the load and capacity relief obtainable from implementing Operating Procedure No. 4. In other words, load and capacity relief assumed obtainable from implementing Operating Procedure No. 4 actions are direct substitutes for capacity resources for meeting the once in 10 years disconnection of firm load criterion. Calling on neighboring Control Areas to provide emergency energy assistance ("tie benefits") is one of the actions of Operating Procedure No. 4. Therefore, the amount of tie benefits assumed obtainable from the interconnected neighboring Control Areas directly displaces that amount of installed capacity resources needed to meet the resource planning reliability criterion. When determining the amount of tie benefits to assume in Installed Capacity Requirement calculations, it is necessary to recognize that, while reliance on tie benefits can reduce capacity resource needs, over-reliance on tie benefits decreases system reliability. System reliability would decrease because each time emergency assistance is requested there is a possibility that the available assistance will not be sufficient to meet the capacity deficiency. The more tie benefits are relied upon to meet the resource planning reliability criterion, and the greater the amount of assistance requested, the greater the possibility that they will not be available or sufficient to avoid implementing deeper actions of Operating Procedure No. 4, and interrupting firm load in accordance with Operating Procedure No. 7 – Action in an Emergency. For example, some of the resources that New York has available to provide tie benefits are demand response resources which have limits on the number of times they can be activated. In addition, none of the neighboring Control Areas are conducting their planning, maintenance scheduling, unit commitment or real-time operations with a goal of maintaining their emergency assistance at a level needed to maintain the reliability of the New England system.

Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: Under Section III.12.9 of the Tariff, the ISO is required to perform a tie reliability benefits study for each FCA, which provides the total overall tie benefit value available from all interconnections with adjacent Control Areas, the contribution of tie benefits from each of these adjacent Control Areas, as well as the contribution from individual interconnections or qualifying groups of interconnections within each adjacent Control Area.

Pursuant to Section III.12.9 of the Tariff, the Installed Capacity Requirement calculations for the 2020-2021 Capacity Commitment Period assume total tie benefits of 1,950 MW based on the results of the tie benefits study for that Capacity Commitment Period. A breakdown of this total value is as follows: 959 MW from Quebec over the Hydro-Quebec Phase I/II HVDC Transmission Facilities, 145 MW from Quebec over the Highgate interconnection, 500 MW from New Brunswick (Maritimes) over the New Brunswick interconnections, and 346 MW from New York over the AC interconnections. Tie benefits are assumed not available over the Cross Sound Cable because the import capability of the Cross Sound Cable was determined to be zero.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD THE SAME AS THE METHODOLOGY USED FOR THE PREVIOUS CAPACITY COMMITMENT PERIOD?

A: Yes. The methodology for calculating the tie benefits that are used in the Installed Capacity Requirement for the 2020-2021 Capacity Commitment Period is the same methodology used to calculate the tie benefits used in the Installed Capacity Requirement for the 2019-2020 Capacity Commitment Period. This methodology is described in detail in Section III.12.9 of the Tariff.

Q: DOES THIS CALCULATION METHODOLOGY CONFORM WITH INDUSTRY PRACTICE AND THE FILED TARIFF REQUIREMENTS?

A: Yes. This probabilistic calculation methodology is widely used by the electric industry. NPCC has been using a similar methodology for many years. The ISO has been using the GE MARS program and a similar probabilistic calculation methodology for tie benefits calculations since 2002. The calculation methodology conforms to the rules filed with and approved by the Commission.

Q: PLEASE EXPLAIN THE ISO'S METHODOLOGY FOR DETERMINING THE TIE BENEFITS FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: The tie benefits study for the 2020-2021 Capacity Commitment Period was conducted using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Control Areas of New Brunswick, New York and Quebec. All of these Control Areas were assumed to be "at criterion," which means that the capacity of all three neighboring Control Areas was adjusted so that they would each have a LOLE of once in ten years when interconnected to each other.

The "at criterion" approach was applied to represent the expected amounts of capacity in each Control Area since each of these areas has structured its planning processes and markets (where applicable) to achieve the "at criterion" level of reliability.

The total tie benefits to New England from New Brunswick (Maritimes), New York and Quebec were calculated first. To calculate total tie benefits, the interconnected system of New England and its directly interconnected neighboring Control Areas were brought to 0.1 days per year LOLE and then compared to the LOLE of the isolated New England system. Total tie benefits equal the amount of firm capacity equivalents that must be added to the isolated New England Control Area to bring New England to 0.1 days per year LOLE.

Following the calculation of total tie benefits, individual tie benefits from each of the three directly interconnected neighboring Control Areas were calculated. Tie benefits from each neighboring Control Area were calculated using a similar analysis, with tie benefits from the Control Area equaling the simple average of the tie benefits calculated from all possible interconnection states between New England and the target Control Area, subject to adjustment, if any, for capacity imports as described below.

If the sum of the tie benefits from each Control Area does not equal the total tie benefits to New England, then each Control Area's tie benefits was pro-rationed so that the sum of each Control Area's tie benefits equals the total tie benefits for all Control Areas. Following this calculation, tie benefits were calculated for each individual interconnection or qualifying group of interconnections, and a similar pro-rationing was performed if the sum of the tie benefits from individual interconnections or groups of interconnections does not equal their associated Control Area's tie benefits.

After the pro-rationing, the tie benefits for each individual interconnection or group of interconnections was adjusted to account for capacity imports. After the import capability and capacity import adjustments, the sum of the tie benefits of all individual interconnections and groups of interconnections for a Control Area then represents the tie benefits associated with that Control Area, and the sum of the tie benefits from all Control Areas then represents the total tie benefits available to New England.

Q: HOW DOES THE ISO DETERMINE WHICH INTERCONNECTIONS MAY BE ALLOCATED A SHARE OF TIE BENEFITS?

A: Tie benefits are calculated for all interconnections for which a "discrete and material transfer capability" can be determined. This standard establishes that if an interconnection has any discernible transfer capability, it will be evaluated. If this nominal threshold is met, the ISO then evaluates the interconnection to determine whether it should be evaluated independently or as part of a group of interconnections. An interconnection will be evaluated with other interconnections as part of a "group of interconnections" if that interconnection is one of two or more AC interconnections that operate in parallel to form a transmission interface in which there are significant overlapping contributions of each line toward establishing the transfer capability, such that the individual lines in the group of interconnections cannot be assigned individual contributions. This standard is contained in Section III.12.9.5 of the Tariff.

Finally, one component of the tie benefits calculation for individual interconnections is the determination of the "transfer capability" of the interconnection. If the interconnection has minimal or no available transfer capability during times when the ISO will be relying on the interconnection for tie benefits, then the interconnection will be assigned minimal or no tie benefits.

Q: ARE THERE ANY INTERCONNECTIONS BETWEEN NEW ENGLAND AND ITS DIRECTLY INTERCONNECTED NEIGHBORING CONTROL AREAS FOR WHICH THE ISO HAS NOT CALCULATED TIE BENEFITS?

A: No. The ISO is calculating tie benefits for all interconnections between New England and its directly interconnected neighboring Control Areas, either individually or as part of a group of interconnections.

Q: WHAT IS THE TRANSFER CAPABILITY OF EACH OF THE INTERCONNECTIONS OR GROUPS OF INTERCONNECTIONS FOR WHICH TIE BENEFITS HAVE BEEN CALCULATED?

A: The following table lists the external transmission interconnections and the transfer capability of each used for calculating tie benefits for the 2020-2021 Capacity Commitment Period:

Table 9 – Transmission Transfer Import Capability of the New England External Transmission Interconnections (MW)

External Transmission Interconnections/Interfaces	Import Capability Into New England
New Brunswick Interconnections	700
Highgate Interconnection	200
Hydro-Quebec Phase I/II HVDC Transmission Facilities	1,400
Cross-Sound Cable	0
New York AC Interface	1,400

One factor in the calculation of tie benefits is the transfer capability into New England of the interconnections for which tie benefits are calculated. In the first half of 2016, the transfer limits of these external interconnections were reviewed based on the latest available information regarding forecasted topology and load forecast information, and it was determined that no changes to the established external interface transmission import limits were warranted. The other factor is the transfer capability of the internal transmission interfaces. For internal transmission interfaces, when calculating tie benefits for the 2020-2021 Installed Capacity Requirement filed herewith, the ISO used the transfer capability values from its most recent transfer capability analyses.

III. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

A. DESCRIPTION OF LOCAL SOURCING REQUIREMENT

Q: WHAT IS THE LOCAL SOURCING REQUIREMENT?

A: The Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone. The Local Sourcing Requirement is the mechanism used to assist in valuing capacity appropriately in constrained areas. It is the amount of capacity needed to satisfy "the higher of" (i) the Local Resource Adequacy Requirement or (ii) the Transmission Security Analysis Requirement. The Local Sourcing Requirement is applied to import-constrained Capacity Zones within New England.

Q: WHAT ARE IMPORT-CONSTRAINED CAPACITY ZONES?

A: Import-constrained Capacity Zones are areas within New England that, due to transmission constraints, are close to the threshold where they may not have enough local resources and transmission import capability to reliably serve local demand.

Q: HOW IS AN IMPORT-CONSTRAINED CAPACITY ZONE DETERMINED?

A: A separate import-constrained Capacity Zone is identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Open Access Transmission Tariff Section II, Attachment K, as a zone for which the second contingency transmission capability results in a line-line Transmission Security Analysis

Requirement, calculated pursuant to Section III.12.2.1.2 and pursuant to ISO New England Planning Procedures, that is greater than the Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model as out-of-service all retirement requests (including any received for the current FCA at the time of this calculation) and Permanent De-List Bids as well as rejected for reliability Static and Dynamic De-List Bids from the most recent previous FCA.

Q: WHICH ZONES WILL BE MODELED AS IMPORT CONSTRAINED CAPACITY ZONES FOR THE ELEVENTH FCA?

A: After applying the import-constrained Capacity Zone objective criteria testing, it was determined that, for the eleventh FCA, the SENE Capacity Zone, which consists of the combined Load Zones of NEMA/Boston, SEMA, and Rhode Island, will be modeled as a separate import-constrained Capacity Zone.

B. DEVELOPMENT OF THE LOCAL SOURCING REQUIREMENT

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE LOCAL SOURCING REQUIREMENT.

A: The methodology for calculating the Local Sourcing Requirement harmonizes the use of the local resource adequacy criteria and the transmission security criteria that the ISO uses to maintain system operational reliability when reviewing de-list bids for the FCA. Because the system must meet both resource adequacy and transmission security requirements, both are developed for each import-constrained zone under Section III.12.2 of the Tariff. Specifically, the Local Sourcing Requirement for an import-constrained zone is the amount of capacity needed to satisfy "the higher of" (i) the Local Resource Adequacy Requirement or (ii) the Transmission Security Analysis Requirement. Under this approach, the ISO calculates a zonal requirement using resource adequacy criteria, referred to as the "Local Resource Adequacy Requirement" and a transmission security analysis referred to as the "Transmission Security Analysis Requirement." The term Local Sourcing Requirement refers to "the higher of" the Local Resource Adequacy Requirement or the requirement calculated based on the Transmission Security Analysis.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE LOCAL RESOURCE ADEQUACY REQUIREMENT.

A: For each import-constrained zone, the Local Resource Adequacy Requirement is determined by modeling the zone under study vis-à-vis the rest of New England. This, in effect, turns the modeling effort into a series of two-area reliability simulations. The reliability target of this analysis is a system-wide LOLE of 0.105 days per year when the transmission constraints between the two zones are included in the model. Because the Local Resource Adequacy Requirement is the minimum amount of resources that must be located in a zone to meet the system-reliability requirements for a zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study until the reliability threshold, or target LOLE of 0.105,[11] is achieved.

[11] An allowance for transmission-related LOLE of 0.005 days per year is applied when determining the Local Resource Adequacy Requirement of a capacity zone.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE TRANSMISSION SECURITY ANALYSIS REQUIREMENT.

A: The Transmission Security Analysis is a deterministic reliability screen of an import-constrained area and is a basic security review set out in Planning Procedure No. 3 and in Section 3.0 of NPCC's Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System.[12] This review determines the requirement of the sub-area to meet its load through internal generation and import capacity and is performed via a series of discrete transmission load flow study scenarios. In performing the analysis, static transmission interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area load with available existing resources and results are presented under the form of a deterministic operable capacity analysis. This analysis also includes evaluations of both: (1) the loss of the most critical transmission element and the most critical generator ("Line-Gen"), and; (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element ("Line-Line"). These deterministic analyses are currently used each day by the ISO's System Operations Department to assess the amount of capacity to be committed day-ahead. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine if the removal of a resource that may be retired or de-listed would violate reliability criteria.

[12] Available at https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf.

Q: WHAT ARE THE DIFFERENCES BETWEEN THE ASSUMPTIONS USED FOR THE DETERMINATION OF THE TRANSMISSION SECURITY ANALYSIS REQUIREMENT AND THE ASSUMPTIONS USED FOR THE DETERMINATION OF THE LOCAL RESOURCE ADEQUACY REQUIREMENT?

A: There are three differences between the assumptions relied upon for the Transmission Security Analysis Requirement and the assumptions relied upon for determining the Local Resource Adequacy Requirement. The first difference relates to the load forecast assumption. Resource adequacy analyses (*i.e.*, the analysis performed in determining the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit, and MRI Demand Curves) are performed using the full probability distribution of load variations due to weather uncertainty. For the purpose of performing the deterministic Transmission Security Analysis, single discreet points on the probability distribution are used; in accordance with ISO New England Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market, the analysis is performed using the 90/10 peak load forecast, which corresponds to a peak load that has a 10% probability of being exceeded based on weather variation.

The second difference relates to the application of assumed forced outages to fast-start (also referred to as "peaking") generating resources. For fast-start generating resources, an operational de-rating factor of 20% was applied in the Transmission Security Analysis instead of a forced outage assumption. This 20% de-rating factor is used because the traditional generating resource forced outage statistical measure used for the Installed

Capacity Requirement calculations does not explicitly capture the peaking generating resources' ability to start and remain on-line when requested to do so after the occurrence of a contingency. Consequently, it has been the ISO's experience and practice to model the start-up performance of the peaking generation in Transmission Security Analyses with a 20% de-rating assumption.

The third difference relates to the reliance on Operating Procedure No. 4 actions, which are not traditionally relied upon in Transmission Security Analyses. Therefore, with the exception of the reliance on Real-Time Emergency Generation Resources, no other load or capacity relief obtainable from implementing Operating Procedure No. 4 actions, are included in the calculation of Transmission Security Analysis Requirements.

Q: PLEASE DESCRIBE THE LOCAL RESOURCE ADEQUACY REQUIREMENT, TRANSMISSION SECURITY ANALYSIS REQUIREMENT, AND LOCAL SOURCING REQUIREMENT FOR THE SENE CAPACITY ZONE FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: For the 2020-2021 Capacity Commitment Period, the Local Resource Adequacy Requirement, Transmission Security Analysis Requirement and the Local Sourcing Requirement for the SENE Capacity Zone are as follows:

Table 10 – SENE Capacity Zone Requirements for the 2020-2021 Capacity Commitment Period (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	9,810	9,580	9,810

IV. MAXIMUM CAPACITY LIMIT

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT?

A: The Maximum Capacity Limit is the maximum amount of capacity that is electrically located in an export-constrained Capacity Zone used to meet the Installed Capacity Requirement.

Q: WHAT ARE EXPORT-CONSTRAINED CAPACITY ZONES?

A: Export-constrained Capacity Zones are areas within New England where the available resources, after serving local load, may exceed the areas' transmission capability to export excess resource capacity.

Q: HOW IS AN EXPORT-CONSTRAINED CAPACITY ZONE DETERMINED?

A: A separate export-constrained Capacity Zone is identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Open Access Transmission Tariff Section II, Attachment K, as a zone for which the Maximum Capacity Limit is less than the sum of the existing qualified capacity and proposed new capacity that could qualify to be procured in the export-constrained Capacity Zone, including existing and proposed new Import Capacity Resources on the export-constrained side of the interface.

Q: WHICH ZONES WILL BE MODELED AS EXPORT CONSTRAINED CAPACITY ZONES FOR THE ELEVENTH FCA?

A: After applying the export-constrained Capacity Zone objective criteria testing, it was determined that, for the eleventh FCA, the NNE Capacity Zone, which consists of the combined Load Zones of Maine, New Hampshire and Vermont, will be modeled as a separate export-constrained Capacity Zone.

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT FOR THE NNE CAPACITY ZONE FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD AND HOW WAS IT CALCULATED?

A: The Maximum Capacity Limit for the NNE Capacity Zone for the 2020-2021 Capacity Commitment Period is 8,980 MW. This number also reflects the tie benefits assumed available over the New Brunswick and Highgate interfaces. The Maximum Capacity Limit was calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff.

In order to determine the Maximum Capacity Limit, the New England Net Installed Capacity Requirement and the Local Resource Adequacy Requirement of the "*Rest of New England*" are needed. *Rest of New England* refers to all areas except the export-constrained Capacity Zone under study. Given that the Net Installed Capacity Requirement is the total amount of resources that the region needs to meet the 0.1 days/year LOLE, and the Local Resource Adequacy Requirement for the *Rest of New England* is the minimum amount of resources required for that area to satisfy its reliability criterion, the difference between the two is the maximum amount of resources that can be used within the export-constrained Capacity Zone to meet the 0.1 days/year LOLE.

V. HQICCs

Q: WHAT ARE HQICCs?

A: HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[13] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff, the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each FCA.

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[13] *See* Section I.2.2 of the Tariff (stating in the definition of "Hydro-Quebec Interconnection Capability Credit" that "[a]n appropriate share of the HQICC shall be assigned to an IRH if the Hydro Quebec (HQ) 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."). *See also* Section III.12.9.7 of the Tariff ("The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.").

Q: WHAT ARE THE HQICC VALUES FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD?

A: The HQICC values are 959 MW for every month of the 2020-2021 Capacity Commitment Period.

VI. MRI DEMAND CURVES

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR THE ELEVENTH FCA.

A: To calculate the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for SENE, and the Export-Constrained Capacity Zone Demand Curve for NNE for the eleventh FCA, the ISO used the MRI methodology, which measures the marginal reliability impact (*i.e.* the MRI), associated with various capacity levels for the system and the Capacity Zones.

To measure the MRI, the ISO uses a performance metric known as "expected energy not served" (or "EENS," which can be described as unserved load). EENS is measured in MWh per year and can be calculated for any set of system and zonal installed capacity levels. The EENS values for system capacity levels are produced by the GE MARS model,[14] in 10 MW increments and applying the same assumptions used in determining

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[14] The GE MARS model is the same simulation system that is already used to develop the Installed Capacity Requirement and other values that specify how much capacity is required for resource adequacy purposes from a system planning perspective. For the development of the MRI Demand Curves, the GE MARS model is used to calculate reliability values using 10 MW additions above and 10 MW deductions below the calculated requirements until a sufficient set of values that covers the full range necessary to produce the MRI Demand Curves is determined.

the Installed Capacity Requirement. These system EENS values are translated into MRI values by estimating how an incremental change in capacity impacts system reliability at various capacity levels, as measured by EENS. An MRI curve is developed from these values with capacity represented on the X-axis and the corresponding MRI values on the Y-axis.

MRI values at various capacity levels are also calculated for the SENE import-constrained Capacity Zone and the NNE export-constrained Capacity Zone using the same modeling assumptions and methodology as those used to determine the Local Resource Adequacy Requirement and the Maximum Capacity Limit for those Capacity Zones, with the exception of the modification of the transmission transfer capability for the SENE import-constrained Capacity Zone as described in more detail below. These MRI values are calculated to reflect the change in system reliability associated with transferring incremental capacity from the Rest-of-Pool Capacity Zone into the constrained capacity zone.

Q: PLEASE EXPLAIN THE USE OF A CAPACITY DEMAND CURVE SCALING FACTOR IN THE MRI DEMAND CURVE METHODOLOGY.

A: In order to satisfy both the reliability needs of the system, which requires that the FCM procure sufficient capacity to meet the 0.1 days per year reliability criterion and produce a sustainable market such that the average market clearing price is sufficient to attract new entry of capacity when needed over the long term, the system and zonal demand curves for the eleventh FCA are set equal to the product of their MRI curves and a fixed demand curve scaling factor . The scaling factor is set equal to the lowest value at which the set of demand curves will simultaneously satisfy the planning reliability criterion and pay the estimated cost of new entry ("Net CONE").[15] In other words, the scaling factor is equal to the value which produces a system demand curve that specifies a price of Net CONE at the net Installed Capacity Requirement (Installed Capacity Requirement minus HQICCs).

To satisfy this requirement, the demand curve scaling factor for the eleventh FCA was developed for the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone in accordance with Section III.13.2.2.4 of the Tariff. The demand curve scaling factor is set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the LOLE is 0.1 days per year.

Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE SYSTEM-WIDE CAPACITY DEMAND CURVE.

A: For purposes of calculating the MRI values for the System-Wide Capacity Demand Curve, the ISO must apply the same modeling assumptions and methodology used in determining the Installed Capacity Requirement. Using these values, which are calculated pursuant to Section III.12.1.1.1 of the Tariff, the ISO must determine the System-Wide Capacity Demand Curve pursuant to Section III.13.2.2.1 of the Tariff. Note that, for this

[15] For the eleventh FCA, Net CONE has been determined as $11.640/kw-month.

year, the ISO used the transition provisions in Section III.13.2.2.1 to determine the System-Wide Demand Curve. The transition curve is a hybrid of the previous linear demand curve design and the new MRI-based design and is described in more detail below.

Q: PLEASE EXPLAIN THE TRANSITION METHODOLOGY USED TO DEVELOP THE SYSTEM-WIDE CAPACITY DEMAND CURVE FOR THE ELEVENTH FCA.

A: The MRI transition period aims to provide a transition from the linear system-wide capacity demand curve methodology used in the ninth and tenth FCAs to the MRI-based system-wide capacity demand curve methodology. This transition period will help to provide a stable and consistent market signal while balancing stakeholder interests. The transition period begins with the eleventh FCA and may last no longer than three FCAs. If certain conditions relating to net Installed Capacity Requirement growth are met, the transition period will end earlier pursuant to Section III.13.2.2.1 of the Tariff. During the MRI transition period, the System-Wide Capacity Demand Curve is represented as a hybrid of the previous linear demand curve design and the new MRI-based demand curve design.

During the MRI transition period, the System-Wide Capacity Demand Curve for the eleventh FCA shall consist of the following three segments:

(1) at prices above $7.03/kW-month and below the Forward Capacity Auction Starting Price, the System-Wide Capacity Demand Curve shall specify a price for system capacity quantities based on the MRI-based demand curve design;

(2) for prices below $7.03/kw-month, the System-Wide Capacity Demand Curve is represented by a linear segment that runs from a price of $7.03 and a capacity quantity of 35,347 MW to a price of $0 and a capacity quantity of 37,053 MW; and

(3) a horizontal line at a price of $7.03/kw-month which connects segments (1) and (2) specified above.

Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE IMPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVE FOR THE SENE CAPACITY ZONE.

A: For import-constrained Capacity Zones, the Local Resource Adequacy Requirement and Transmission Security Analysis Requirement values both play a role in defining the MRI-based demand curves as they do in setting the Local Sourcing Requirement. Under III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI value of various capacity levels, for each import-constrained Capacity Zone. For purposes of these calculations, the ISO applies the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area is reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero. By using a transfer capability that accounts for both the Transmission Security Analysis and the

Local Resource Adequacy Requirements, the ISO applies the same "higher of" logic used in the Local Sourcing Requirement to the derivation of sloped zonal demand curves.

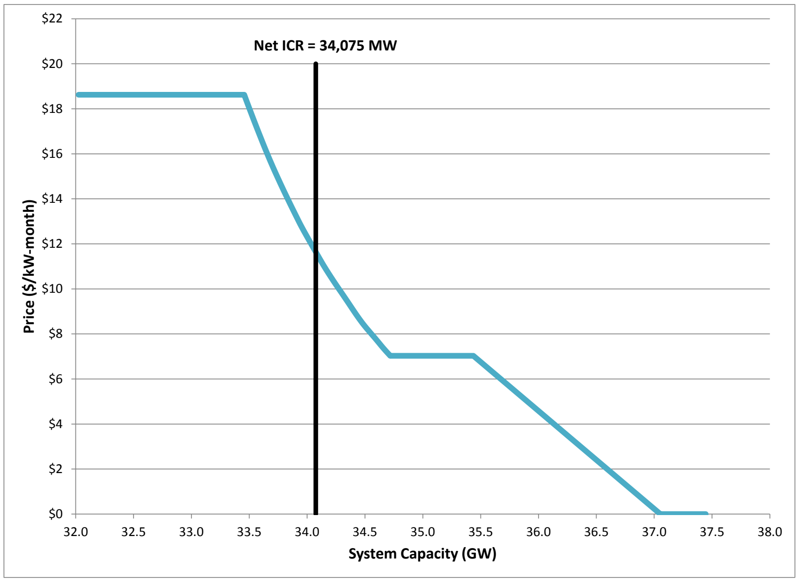
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVE FOR THE NNE CAPACITY ZONE.

A: Under Section III.12.2.1.3 of the Tariff, prior to each FCA, the Export-Constrained Capacity Zone Demand Curve is calculated using the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the Export-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For the eleventh FCA, the only export-constrained Capacity Zone is NNE and, therefore, there is only one Export-Constrained Capacity Zone Demand Curve.

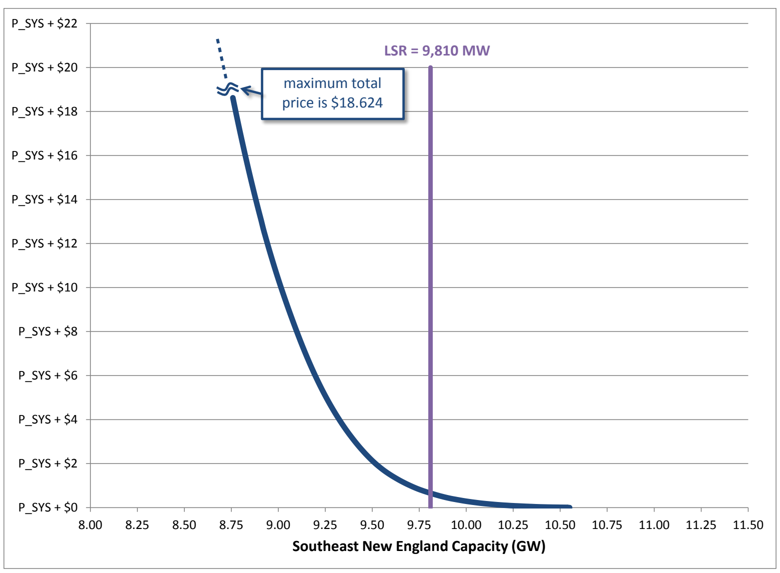
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR THE ELEVENTH FCA?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI Demand Curves for the eleventh FCA:

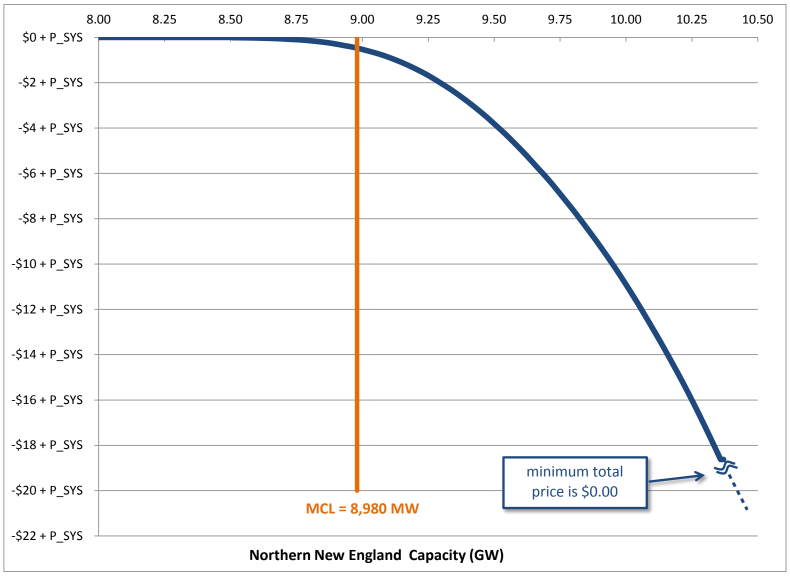
1. System-Wide Capacity Demand Curve



2. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone



3. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/8/2016

Carissa Sedlacek

Executed on 11/8/2016

Maria Scibelli

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