November 10, 2015

VIA ELECTRONIC FILING

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

Re: *ISO New England Inc.*, Docket No. ER16-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2019-2020 Capacity Commitment Period

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO"), hereby electronically submits to the Federal Energy Regulatory Commission ("Commission") this transmittal letter and related materials which identify the following values for the tenth Forward Capacity Auction ("FCA"):[2] (i) Installed Capacity Requirement;[3] (ii) Local Sourcing Requirement for the Southeastern New England ("SENE") Capacity Zone;[4] (iii) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (iv) capacity requirement values needed to develop the demand curve for the 2019-2020 Capacity Commitment Period ("Demand Curve Values").[5] The Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, HQICCs and Demand Curve Values are collectively referred to herein as the "ICR-Related Values." This filing letter also explains why Maximum Capacity Limits were not established for the 2019-2020 Capacity Commitment Period.

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1 16 U.S.C. § 824d (2014).

2 The tenth Forward Capacity Auction is associated with the 2019-2020 Capacity Commitment Period, which starts on June 1, 2019 and ends on May 31, 2020.

3 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").

4 The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA") and Northeastern Massachusetts ("NEMA")/Boston Capacity Zones.

5 Pursuant to Section III.12.3 of the Tariff, the Installed Capacity Requirement must be filed 90 days prior to the applicable FCA. The tenth FCA, which is the primary FCA for the 2019-2020 Capacity Commitment Period, is scheduled to commence on February 8, 2016.

The ISO is proposing an Installed Capacity Requirement (net of HQICCs) of 34,151 MW,[6] a Local Sourcing Requirement for the SENE Capacity Zone of 10,028 MW, HQICCs of 975 MW per month, and Demand Curve Values of 33,076 MW (1-in-5 LOLE)[7] and 37,053 MW (1-in-87 LOLE). The derivation of these values is discussed in Sections III-VI of this filing letter, and in the attached joint testimony of Stephen J. Rourke, Vice President of System Planning at the ISO, and Peter K. Wong, Manager of Resource Adequacy at the ISO (the "Rourke-Wong Testimony"). The 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.[8] For the tenth FCA, the only change in the set of assumptions used to calculate the ICR-Related Values is the inclusion of behind-the-meter photovoltaic

[6] 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 1,990 MW.

[7] LOLE stands for "loss of load expectation."

[8] *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); *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 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").

("PV") resources that are not yet reflected in historical loads as a reduction in the load forecast. This change, which is described in Section III.B.1 of this filing letter and in the Rourke-Wong Testimony, addresses the Commission's directive in its January 2, 2015 Order accepting the Installed Capacity Requirement and related values for the ninth FCA (the "January 2 Order").[9] Accordingly, the Commission should accept the proposed values without change to become effective on January 9, 2016.

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").

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II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values for the tenth FCA 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."[10] Under Section 205, the Commission "plays 'an essentially passive

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[9] *ISO New England Inc.*, 150 FERC ¶ 61,003 (2015) at P 20.

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

and reactive' role"[11] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[12] 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."[13] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[14] 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.[15]

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 net Installed Capacity Requirement for the 2019-2020 Capacity Commitment Period (*i.e.*, the Installed Capacity Requirement minus HQICCs) is the amount of installed capacity to be procured in the tenth FCA, which will be held in February 2016.[16]

The ISO is proposing an Installed Capacity Requirement of 35,126 MW for the tenth FCA. This value reflects tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Quebec in the aggregate amount of 1,990 MW. However, the 35,126 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 975 MW per month is applied

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

[12] *Id.* at 9.

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

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

[15] *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)).

[16] Pursuant to Section III.13 of the Tariff, the ISO administers the FCA in order "to procure the amount of capacity needed in the New England Control Area."

to reduce the portion of the Installed Capacity Requirement that is allocated to the Interconnection Rights Holders. Thus, the net amount of capacity to be purchased in the FCA to meet the Installed Capacity Requirement, after deducting the HQICC value, is 34,151 MW.

B. Development of the Installed Capacity Requirement

The calculation methodology used to develop the ICR-Related Values for the tenth FCA is the same as that used to calculate the values for previous FCAs. As in previous years, the values for this year's 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.[17] With the exception of the inclusion of behind-the-meter PV resources that are not yet reflected in historical loads as a reduction in the load forecast, the methodology used to develop the assumptions generally is the same as that used to calculate the Installed Capacity Requirement and related values for previous FCAs.[18] The modeling assumptions have been updated to reflect changed system conditions since the development of the Installed Capacity Requirement and related values for the ninth FCA. These updated assumptions are described below.

1. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2019-2020 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 2019-2020 Capacity Commitment Period, the ISO used the forecast published in the 2015 – 2024 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2015 ("2015 CELT Report").[19] The 2015 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.[20] This methodology reflects economic and demographic

[17] Rourke-Wong Testimony at 10.

[18] *See* note 8, *supra*.

[19] Rourke-Wong Testimony at 12.

[20] *See, e.g.*, 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.

assumptions as reviewed by the NEPOOL Load Forecast Committee.[21]

The projected New England Control Area summer 50/50 peak load[22] for the 2019-2020 Capacity Commitment Period is 29,861 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.[23]

New for the Tenth FCA: Inclusion of Behind-the-Meter PV Resources that are not yet Reflected in Historical Loads in the ICR-Related Values Calculations

The rapid growth and installation of PV resources led the ISO, working with the Distributed Generation Forecast Working Group ("DGFWG"), to develop a forecast that captures the effects of recently installed PV resources and PV resources expected to be installed within the forecast horizon in order to forecast the potential future peak loads as accurately as possible. The ISO completed the region's first (interim) PV forecast in April of 2014 and incorporated it in long-term, ten-year transmission planning. However, in 2014, the ISO did not reflect the PV forecast in its ICR-Related Values calculations.

In its January 2 Order accepting the Installed Capacity Requirement and related values for the ninth FCA, the Commission agreed with the ISO that the ISO needed to examine the market and operational issues associated with incorporating distributed generation into the Installed Capacity Requirement calculation. The Commission recognized the ISO's commitment to work with stakeholders to explore whether and how PV resources that had not been captured through existing Forward Capacity Market ("FCM") mechanisms should impact the Installed Capacity Requirement calculations based on the PV forecast. The Commission directed the ISO to fully explore the incorporation of distributed generation into the Installed Capacity Requirement calculation in the stakeholder process. The Commission stated that it expected the ISO to do this on a schedule that would allow these factors to be reflected, if determined appropriate, in the Installed Capacity Requirement calculation for the tenth FCA.

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

[22] 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.

[23] *See* Rourke-Wong Testimony at 11.

In accordance with the January 2 Order, the ISO worked with stakeholders for a period of over ten months, which included a presentation of the ISO's framework to include PV resources in the ICR calculations to the Reliability Committee in February 2015. The development of the 2015 PV forecast by the ISO and the DGFWG took place during the months of December 2014 to April 2015. The DGFWG is made up of stakeholders that include representatives of the six New England states' public utilities regulatory commissions who provide comments and suggestions on the forecast assumptions and methodology. The DGFWG met three times (December 2014, February 2015, and April 2015) and its members provided numerous comments on the assumptions, methodology and results of the preliminary forecasts which were reflected in the final PV forecast. In addition, as part of the review of the comprehensive 2015 Load Forecast, the PV forecast was discussed at the April 28, 2015 meeting of the Planning Advisory Committee ("PAC") where stakeholders had an additional opportunity to provide input. In May, June, July, and August 2015, the Power Supply Planning Committee ("PSPC") discussed the modeling assumptions for calculating the ICR-Related Values. These discussions included resource adequacy related issues surrounding the appropriate incorporation of PV resources from the PV forecast into the ICR-Related Values calculations.[24]

To address the Commission's directive, the ISO analyzed four categories of PV resources in the New England markets. The first category includes PV resources that participate in the FCM. For ICR-Related Values calculations, these resources are modeled for the Capacity Commitment Period of interest if they are qualified to participate in the FCA associated with that Capacity Commitment Period. The second category includes PV resources that do not participate in the FCM but participate in the energy market as Settlement Only Resources ("SORs"). As such, pursuant to Section III.12.7.2 of the Tariff, these resources are not modeled in ICR-Related Values calculations. The third category includes behind-the-meter PV resources embedded in load. These are PV resources that have been installed with enough time for their historical output to become part of the model estimation period of historical load used to forecast future load. The load forecast captures the impact of these resources on load based on estimates via the reconstitution of their hourly historical production. The fourth category includes the behind-the-meter PV resources that are not embedded in load ("BTMNEL"). These are in-service behind-the-meter PV resources that have not been captured in historical loads and behind-the-meter PV resources forecasted to be installed prior to the Capacity Commitment Period of interest. To ensure that PV resources are properly accounted for in the ICR-Related Values, and in order to avoid double-counting, the PV forecast was separated into the four

[24] After the PSPC reviewed the ICR-Related Values, the values were presented to the Reliability Committee. As explained in Section VII of this filing letter, while the Reliability Committee recommended that the Participants Committee support the ICR-Related Values for the tenth FCA, the Participants Committee supported the HQICCs, but it did support not the Installed Capacity Requirement, the Local Sourcing Requirement for the SENE Capacity Zone, or the Demand Curve Values.

distinct market participation categories described above. In order to determine the load reduction impact of BTMNEL PV resources, the ISO used solar PV production data of currently installed behind-the-meter PV resources provided by the states and distribution utilities. The ISO calculated the PV already embedded in load and then adjusted the load forecast by the forecasted BTMNEL PV.[25] This adjustment resulted in a 390 MW reduction in the Installed Capacity Requirement for the 2019-2020 Capacity Commitment Period.

2. Resource Capacity Ratings

The Installed Capacity Requirement for the tenth FCA is based on the latest available ratings[26] at the time of the Installed Capacity Requirement calculation of Existing Capacity Resources that have qualified for the tenth FCA. These resources are described in the qualification informational filing for the tenth FCA that is being filed concurrently on November 10, 2015.[27]

Resource additions and attritions are not assumed in the calculation of the Installed Capacity Requirement for the tenth FCA, 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 Rourke-Wong Testimony, are designed to address these resource addition and attrition uncertainties.[28]

3. Resource Availability

The proposed Installed Capacity Requirement value for the tenth FCA reflects generating resource availability assumptions based on historical scheduled maintenance and forced outages of

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[25] The development of the 2015 PV forecast is further explained in the Wong-Rourke Testimony at 16-19.

[26] The resource capacity ratings for the 2019-2020 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 capacity ratings reflected in the Commission-approved Installed Capacity Requirements for the first eight primary FCAs. *See* 2017-2018 ICR Filing at 11-12 and 2017-2018 ICR Letter Order; 2016-2017 ICR Filing at 11-12; 2015-2016 ICR Filing 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.

[27] *ISO New England Inc.*, Informational Filing for Qualification in the Forward Capacity Market, filed on November 10, 2015 at Attachment C.

[28] Rourke-Wong Testimony at 21.

these capacity resources.[29] For generating resources, individual unit scheduled maintenance assumptions are based on each unit's most recent historical five-year average of scheduled maintenance. The individual generating resource's forced outage assumptions are based on the resource's five-year historical equivalent forced outage rate data submitted to the ISO database. 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 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 the Passive Demand Resources are modeled as 100% available. The 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 2010 through 2014.

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 formula.[30] 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.

[29] The assumed resource availability ratings for the 2019-2020 Capacity Commitment Period are discussed in the Rourke-Wong Testimony at 22-23. 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 nine primary FCAs. *See* note 26, *supra*.

[30] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for the tenth 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.

The Installed Capacity Requirement for the 2019-2020 Capacity Commitment Period proposed by the ISO reflects tie benefits calculated from the New Brunswick, New York and Quebec Control Areas.[31] 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 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 tenth FCA assume total tie benefits of 1,990 MW based on the results of the tie benefits study for the 2019-2020 Capacity Commitment Period. A breakdown of this total value by Control Area is as follows: 975 MW from Quebec over the Phase II interconnection, 142 MW from Quebec over the Highgate interconnection, 519 MW from New Brunswick (Maritimes) over the New Brunswick ties and 354 MW from New York over the AC ties.[32] 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.[33]

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 2015, 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

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[31] *See* 2014-2015 ICR Filing, Rourke-Wong 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, and the 2018-2019 Capacity Commitment Period.

[32] Rourke-Wong Testimony at 28.

[33] 2014-2015 ICR Filing at 13-19.

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 2019-2020 Installed Capacity Requirement, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.[34]

IV. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

A. Description of the Local Sourcing Requirement and Maximum Capacity Limit

In the FCM, the ISO must also calculate Local Sourcing Requirements and Maximum Capacity Limits to be used, if necessary, in each FCA and the reconfiguration auctions for a Capacity Commitment Period. A Local Sourcing Requirement is "the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone."[35] A Maximum Capacity Limit is "the maximum amount of capacity that can be procured in an export-constrained Capacity Zone [to meet the Installed Capacity Requirement]."[36] The general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to procure capacity resources such that, when considered in combination with the transfer capability of the transmission system, they are electrically distributed within the New England Control Area in a manner that ensures that the minimum amount of resources purchased in the FCA will meet NPCC's and the ISO's bulk power system reliability planning criteria.

For the tenth FCA, the ISO calculated the Local Sourcing Requirements for the SENE Capacity Zone. The Local Sourcing Requirement was calculated using the methodology that is reflected in Section III.12.2 of the Tariff. The Local Sourcing Requirement for the SENE Capacity Zone is 10,028 MW. The ISO determined that there are no export-constrained Capacity Zones for the 2019-2020 Capacity Commitment Period and, accordingly, Maximum Capacity Limits were not established for the tenth FCA.

2. Development of the Local Sourcing Requirement

The calculation methodology for determining Local Sourcing Requirements utilizes both Local Resource Adequacy criteria as well as criteria used in the Transmission Security Analysis

[34] Rourke-Wong Testimony at 34, Table 9.

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

[36] *Id.*

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 provide that both resource adequacy and transmission security-based requirements 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.[37]

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").[38] 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 area's reliability. Using the analysis, the ISO identifies a resource requirement sufficient to allow the system to operate through stressed conditions.[39] 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 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 Rourke-Wong Testimony.[40]

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

[38] Copy available at http://www.iso-ne.com/rules_proceds/isone_plan/pp10/pp10_r13.pdf.

[39] *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).

[40] Rourke-Wong Testimony at 41-42.

The Local Resource Adequacy Requirement value and Transmission Security Analysis Requirement value for the SENE Capacity Zone calculated for the tenth FCA are, respectively, 9,584 MW and 10,028 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 10,028 MW.

V. HQICCs

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").[41] 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 Capacity Commitment Period's FCA. The HQICC value for the 2019-2020 Capacity Commitment Period is 975 MW per month.

VI. DEMAND CURVE VALUES

Starting with the ninth FCA, a demand curve is used in the FCA and, accordingly, the ISO calculated the capacity requirement values needed to develop the demand curve for the 2019-2020 Capacity Commitment Period. Specifically, Section III.12.1 of the Tariff states that "[t]he ISO shall determine, by applying the same modeling assumptions and methodology used in determining the Installed Capacity Requirement, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve." Hence, although capacity requirements for the demand curve are now also being calculated, the methodology for determining those values is the same as that used for calculating the Installed Capacity Requirement. Section III.13.2.2 of the Tariff determines that the demand curve capacity requirement values are those calculated (net of HQICCs) at 0.200 (1-in-5) LOLE and 0.011 (1-in-87) LOLE. The 1-in-5 LOLE and 1-in-87 LOLE Demand Curve Values are 33,076 MW and 37,053 MW, respectively.

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[41] *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.").

VII. STAKEHOLDER PROCESS

As in past years, the ISO, in consultation with NEPOOL and other interested parties, developed the proposed Installed Capacity Requirement and related values for the 2019-2020 Capacity Commitment Period through an extensive stakeholder process over the course of seven months. This process included review by NEPOOL's PSPC during the course of four meetings.[42] In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[43] Among other responsibilities, NESCOE is responsible for providing feedback on the proposed Installed Capacity Requirement value at the relevant NEPOOL Reliability Committee and Participants Committee meetings, and was in attendance for the meetings at which the ICR-Related Values for the tenth FCA were discussed.[44]

On September 15, 2015, the Reliability Committee voted to recommend, by a show of hands (with two oppositions and four abstentions) that the Participants Committee support the HQICCs. The Reliability Committee also voted to recommend, by a show of hands (with three oppositions and nine abstentions), that the Participants Committee support the Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, and the Demand Curve Values. On October 2, 2015, the Participants Committee supported the HQICCs (with oppositions and abstentions noted). However, the Participants Committee did not support the Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, and the Demand Curve Values, with a vote of 53.08% in favor.

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for the tenth FCA to be effective on January 9, 2016 (which is 60 days from the filing date), so that the proposed values can be used as part of the tenth FCA to be conducted in February 2016.

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for the 2019-2020 Capacity Commitment Period and is made pursuant to Section 205 of the FPA. Section 35.13 of the Commission's

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[42] 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.

[43] *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).

[44] *See* the NESCOE Funding Filing at p. 14.

regulations generally requires public utilities to file certain cost and other information related to an examination of cost-of-service rates.[45] 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.

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

- This transmittal letter;
- Attachment 1: Joint Testimony of Messrs. Stephen J. Rourke and Peter K. Wong;
- Attachment 2: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been emailed.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 9, 2016.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/committees/nepool_part/index.html. 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, there 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 the background section to this transmittal letter.

35.13(b)(6) - As explained above, the ISO has sought the advisory input from

[45] 18 C.F.R. § 35.13.

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 ISO requests that the Commission accept the proposed ICR-Related Values reflected in this submission for filing without change to become effective January 9, 2016.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: <u>*/s/ Kevin W. Flynn*</u>

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Attachments
cc : Entities listed in Attachment 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER16-___-000**

PREPARED TESTIMONY OF
MR. STEPHEN J. ROURKE and MR. PETER K. WONG
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: **Mr. Rourke:** My name is Stephen J. Rourke. I am Vice President of System Planning with ISO New England Inc. (the "ISO"). My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Mr. Wong: My name is Peter K. Wong. I am the Manager of Resource Adequacy with the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: MR. ROURKE, PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I have a Bachelor of Science degree in Electrical Engineering from Worcester Polytechnic Institute and a Master of Business Administration degree from Western New England University. In my current position as Vice President of System Planning, I am responsible for planning for a reliable New England bulk power system according to prescribed reliability standards and guidelines of the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC");

overseeing development of the annual Regional System Plan ("RSP"); performing analysis and approval of new transmission and generation interconnection projects, including the approval of qualification of generating capacity resources, demand resources, and import capacity resources to participate in the Forward Capacity Auction ("FCA"); [1] implementing the Federal Energy Regulatory Commission ("Commission" or "FERC") approved generator interconnection process; developing the ISO's findings for Transmission Cost Allocation; and supporting the capacity market in New England.

Previously, I served as the ISO's Director, Reliability and Operations Services. I was also a former manager of the Rhode Island—Eastern Massachusetts—Vermont Energy Control ("REMVEC") center in Westborough, Massachusetts and former manager of marketing operations for Northeast Utilities/Select Energy Inc. in Berlin, Connecticut. I have over 30 years of experience in the operations and planning of the New England bulk power system.

Q: MR. WONG, PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A: I hold a Bachelor of Science degree in Electrical Engineering from the University of Connecticut and a Master of Business Administration degree from Western New England University.

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

I have been the Manager of Resource Adequacy for the ISO since 1999. Before that, I served for about seven years as the Manager of Operations Planning & Analysis for the staff of the New England Power Exchange ("NEPEX"), the power pool operator that preceded the ISO, and then for the ISO once it was established.

I have worked at the ISO and its predecessor for more than 40 years. During this time, in addition to my most recent duties described above, I have held various positions in the Power Supply Planning department of New England Power Planning ("NEPLAN"). My last position at NEPLAN was Manager of Power Supply Planning. During my 15 years with NEPLAN Power Supply Planning, I was involved in all matters related to Objective Capability (which is now referred to as the "Installed Capacity Requirement") and resource adequacy. I currently serve as the Chair of the New England Power Pool ("NEPOOL")[2] Power Supply Planning Committee, 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 and Maximum Capacity Limits for New England.

Q. ARE THE PROCESS AND METHODOLOGY FOR DEVELOPING THE INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES THE SAME AS THOSE USED FOR THE LAST INSTALLED CAPACITY REQUIREMENT FILING?

[2] NEPOOL is the stakeholder advisory organization for the ISO, which is the Regional Transmission Organization for New England.

A. Yes. The process and methodology for developing the Installed Capacity Requirement and related values for the tenth FCA are the same as those used in the calculation of the Installed Capacity Requirement and related values for the ninth FCA. However, there is a change in the load forecast assumption used in the calculation of the Installed Capacity Requirement and related values. That change is described in Section II.B.1 of this testimony.

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,[3] and the Hydro-Quebec Interconnection Capability Credits ("HQICCs") for the 2019-2020 Capacity Commitment Period, which is the Capacity Commitment Period associated with the tenth FCA to be conducted in February 2016. The 2019-2020 Capacity Commitment Period starts on June 1, 2019 and ends on May 31, 2020. This testimony also explains why Maximum Capacity Limits were not established for the 2019-2020 Capacity Commitment Period. Our testimony also addresses the capacity requirement values needed to develop the System-wide Capacity Demand Curve ("Demand Curve Values")

[3] As explained in the ISO's Informational Filing for the tenth FCA, which is being submitted to the Commission concurrently with this filing, the ISO considered two new boundaries for evaluation in the tenth FCA's Capacity Zone formation process (Northern New England ("NNE") and SENE). *See ISO New England Inc.*, Informational Filing for Qualification in the Forward Capacity Market, filed on November 10, 2015. On May 29, 2015, the Commission accepted the ISO's filing with two potential new boundaries for Capacity Zones for the tenth FCA. *See ISO New England Inc.*, 151 FERC ¶ 61,183 (2015). Since that time, in accordance with Section III.12.4 of the Tariff, the ISO has determined that it will model two Capacity Zones: SENE and Rest of Pool.

for the tenth FCA. The Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, HQICCs and Demand Curve Values are collectively referred to herein as the "ICR-Related Values."

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.
>
> 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.[4]

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

A: The ICR-Related Values for the 2019-2020 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 NEPOOL Power Supply Planning Committee ("PSCPC") 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 tenth FCA 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 Power Supply Planning Committee, Reliability Committee and Participants Committee. The NEPOOL Reliability Committee supported the ICR-Related Values; while the NEPOOL Participants Committee supported the proposed HQICC values, it did not support the proposed Installed Capacity Requirement, Local Sourcing Requirement for the SENE Capacity Zone, and Demand Curve Values. The ISO is filing with the Commission the ICR-Related Values for the tenth FCA.

[4] Copy available at http://www.iso-ne.com/rules_proceds/isone_plan/pp03/index.html.

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 Requirements, Local Sourcing Requirements, Maximum Capacity Limits and Demand Curve Values, 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 tenth FCA were discussed and considered.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE CALCULATED BY THE ISO FOR THE TENTH FCA.

A: The Installed Capacity Requirement value for the tenth FCA is 35,126 MW.

Q: IS THIS THE AMOUNT OF INSTALLED CAPACITY THAT WILL BE RELIED UPON FOR PURPOSES OF CONDUCTING THE TENTH FCA?

A: No. The 35,126 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of the Tariff. After deducting the monthly HQICC value of 975 MW,[5] the net Installed Capacity Requirement for use in the tenth FCA is 34,151 MW.

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] The development of the HQICCs is explained in Section V of this testimony.

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.

The use of proxy resources, in the calculation of the Installed Capacity Requirement for the tenth FCA, avoids an inappropriate increase or decrease in the system LOLE that may result from assuming a specific type of unit addition. Proxy resources reflect the average availability and size of all New England resources.[6] Specifically, each proxy resource has size and availability characteristics such that when proxy resources are used in place of all the resources assumed to be available to the system, the resulting LOLE is unchanged. The use of proxy resources for calculating the Installed Capacity Requirement is a methodology supported by New England stakeholders since the establishment of a regional installed capacity/reserve requirement in the 1970s.

[6] A presentation made to the PSPC is available at: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf.

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 TENTH FCA 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 TENTH FCA.

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 monthly 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 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 2019-2020 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.

Q: PLEASE DESCRIBE THE PROJECTED NEW ENGLAND AND CAPACITY ZONE 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD.

A: The following table shows the 50/50 and 90/10 peak load forecast, based on the 2015 - 2024 Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT") load forecast for the 2019-2020 Capacity Commitment Period.

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

	50/50	90/10
New England	29,861	33,051
SENE	12,282	13,342

Q: HAS ANYTHING CHANGED IN THE LOAD FORECAST ASSUMPTION SINCE THE LAST INSTALLED CAPACITY REQUIREMENT FILING?

A: Yes. This year, for the first time in the ICR-Related Values calculations, the ISO is incorporating an assumed forecast of photovoltaic ("PV") resources that are neither capacity resources in the Forward Capacity Market ("FCM") nor counted as an ISO energy-only resource. While these behind-the-meter PV resources do not report their energy output to the ISO, their output directly reduces load. Some behind-the-meter PV resources have been in service long enough to be captured in the historical loads and, as such, they are deemed already embedded in load. However, there are other behind-the-meter PV resources that have been recently installed and, as a result, there has not been enough time for their load reduction effect to be captured in historical loads. These recently installed behind-the-meter PV resources and forecasted behind-the-meter PV resources to be installed in the future constitute a category of PV resources designated as Behind-the-Meter Not Embedded in Load ("BTMNEL") PV resources. For the first time in ICR calculations, the load forecast was adjusted to reflect the expected load reduction impact of these BTMNEL PV resources.

Q: WHAT IS THE REASON FOR THE CHANGE?

A: The rapid growth and installation of PV resources led the ISO, working with the Distributed Generation Forecast Working Group ("DGFWG"), to develop a forecast that captures the effects of the recently installed PV resources and PV resources expected to be installed within the forecast horizon in order to forecast the potential future peak loads as accurately as possible. The ISO completed the region's first (interim) PV forecast in April of 2014 and incorporated it in long-term, ten-year transmission planning. However, in 2014, the ISO did not reflect the PV forecast in the calculations of the Installed Capacity Requirement and related values.

In its January 2, 2015 order accepting the Installed Capacity Requirement and related values for the ninth FCA ("January 2 Order"), the Commission agreed with the ISO that the ISO needed to examine the market and operational issues associated with incorporating distributed generation into the Installed Capacity Requirement calculation.

The Commission recognized the ISO's commitment to work with stakeholders to explore whether and how PV resources not currently captured through existing FCM mechanisms should impact the Installed Capacity Requirement and related values calculations based on the PV forecast. Thus, the Commission directed the ISO to fully explore the incorporation of distributed generation into the Installed Capacity Requirement calculation in the stakeholder process.[7] The Commission stated that it expected the ISO to do this on a schedule that would allow these factors to be reflected, if determined appropriate, in the Installed Capacity Requirement calculation for the tenth FCA.

Q: PLEASE DESCRIBE THE STAKEHOLDER PROCESS FOR ADDRESSING THE COMMISSION'S DIRECTIVE IN THE JANUARY 2 ORDER.

A: To address the Commission's directive in the January 2 Order, the ISO worked with stakeholders for a period of over ten months, which included a presentation of the ISO's framework to include PV resources in the Installed Capacity Requirement and related values calculations to the Reliability Committee in February 2015.

The development of the 2015 PV forecast by the ISO and the DGFWG took place during the months of December 2014 to April 2015. The DGFWG is made up of stakeholders and representatives of the six New England states' public utilities regulatory commissions who provide comments and suggestions on the forecast assumptions and methodology. The DGFWG met three times (December 2014, February 2015, and April 2015) and its members provided numerous comments on the assumptions, methodology

[7] *ISO New England Inc.*, 150 FERC ¶ 61,003 (2015) at P 20.

and results of the preliminary forecasts which were reflected in the final PV forecast. In addition, as part of the review of the comprehensive 2015 Load Forecast, the PV forecast was discussed at the April 28, 2015 meeting of the Planning Advisory Committee ("PAC") where stakeholders had an additional opportunity to provide input.

The PSPC discussed the resource adequacy related issues surrounding the appropriate incorporation of PV resources from the PV forecast into the ICR-Related Values calculations, including modeling assumptions, in May, June, July and August 2015.

The Reliability Committee recommended that the Participants Committee support the ICR-Related Values for the tenth FCA at its September 15, 2015 meeting. At its October 2, 2015 meeting, the Participants Committee supported the HQICCs. The Participants Committee, however, did not support the Installed Capacity Requirement, the Local Sourcing Requirement for the SENE Capacity Zone, or the Demand Curve Values, with a vote of 53.08% in favor.

Q: PLEASE DESCRIBE THE TYPES OF PV RESOURCES AS THEY RELATE TO THE ISO NEW ENGLAND MARKETS.

A: The ISO classified PV resources into four categories. The first category includes PV resources that participate in the FCM. For ICR-Related Values calculations, these resources are modeled for the Capacity Commitment Period of interest if they are qualified to participate in that Capacity Commitment Period. The second category includes PV resources that don't participate in the FCM but participate in the energy market as Settlement Only Resources ("SORs"). As such, pursuant to Section III.12.7.2 of the Tariff, these resources are not modeled in ICR-Related Values calculations. The third category includes behind-the-meter PV resources embedded in load. These are PV resources that have been installed with enough time for their historical output to become part of the model estimation period of historical load used to forecast future load. The load forecast captures the impact of these resources on load based on estimates via the reconstitution of their hourly historical production. The fourth category includes the behind-the-meter PV resources that are not embedded in load (BTMNEL). These are in-service behind-the-meter PV resources that have not been captured in the historical load and behind-the-meter PV resources forecasted to be installed prior to the Capacity Commitment Period of interest.

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 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 state PV profiles from three years of historical data (2012 – 2014). These were developed from production data available from 665 currently installed individual PV sites throughout New England. These profiles were used as the basis for determining a summer Seasonal Claimed Capability ("SCC") rating of 40% of the nameplate PVMW value.

As PV resources are developed and go into service, they become either market-facing (*i.e.*, they participate in FCM and/or the wholesale energy market) or behind-the-meter resources that reduce the ISO's system load. To ensure that PV resource are properly accounted for in the ICR-Related Values, and in order to avoid double-counting, the PV forecast was separated into the four distinct market participation categories described above.

The PV forecast values used in the ICR-Related Values reflect only PV resources that are forecasted to be behind-the-meter. To determine the load reduction impact of these resources, the ISO used solar PV production data of currently installed behind-the-meter PV resources provided by the states and distribution utilities.

In addition, since the 2015 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 2019-2020 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 BTMNEL 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 BTMNEL PV for 2019-2020 (MW)[8]

Month	2019/2020
Jun	367.1
Jul	369.2
Aug	371.4
Sep	373.8
Oct	0
Nov	0
Dec	0
Jan	0
Feb	0
Mar	0
Apr	0
May	389.3

[8] 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 BTMNEL PV adjustment resulted in a 390 MW reduction in the Installed Capacity Requirement for the 2019-2020 Capacity Commitment Period.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES FOR THE TENTH FCA.

A: The ICR-Related Values for tenth FCA were developed based on the Existing Qualified Capacity Resources for the 2019-2020 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 2019-2020 CAPACITY COMMITMENT PERIOD?

A: The following tables show the make-up of the 33,484 MW of Capacity Resources assumed in the calculation of the Installed Capacity Requirement and related values.

Table 3– Qualified Existing Non-Intermittent Generating Capacity by Load Zone (MW)[9]

[9] 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.

Load Zone	Summer
MAINE	2,863.774
NEW HAMPSHIRE	4,043.605
VERMONT	222.098
CONNECTICUT	9,063.732
RHODE ISLAND	1,867.339
SOUTH EAST MASSACHUSETTS	4,683.952
WEST CENTRAL MASSACHUSETTS	3,732.636
NORTH EAST MASSACHUSETTS & BOSTON	3,227.714
Total New England	**29,704.850**

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

Load Zone	Summer	Winter
MAINE	292.832	401.878
NEW HAMPSHIRE	157.295	215.912
VERMONT	71.780	124.302
CONNECTICUT	172.684	188.939
RHODE ISLAND	3.372	5.220
SOUTH EAST MASSACHUSETTS	83.314	78.057
WEST CENTRAL MASSACHUSETTS	66.670	97.066
NORTH EAST MASSACHUSETTS & BOSTON	71.172	72.260
Total New England	**919.119**	**1,183.634**

Table 5– Qualified Existing Import Capacity (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 in the Installed Capacity Requirement calculation was one Administrative Export (known sale) of 100 MW to the Long Island Power Authority ("LIPA") over the Cross Sound Cable ("CSC") Direct Current ("DC") interface.

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

Export	Summer
LIPA over Cross Sound Cable	(100.000)

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	164.811	-	149.386	7.482	321.679
NEW HAMPSHIRE	101.215	-	12.798	14.022	128.035
VERMONT	120.090	-	31.900	4.918	156.908
CONNECTICUT	78.815	371.437	77.374	52.941	580.567
RHODE ISLAND	197.599	-	60.362	15.720	273.681
SOUTH EAST MASSACHUSETTS	292.685	-	51.987	12.722	357.394
WEST CENTRAL MASSACHUSETTS	293.340	49.645	58.684	25.098	426.767
NORTH EAST MASSACHUSETTS & BOSTON	548.466	-	67.329	10.439	626.234
Total New England	1,797.021	421.082	509.820	143.342	2,871.265

Although capacity resource data are tabulated under the eight settlement Load Zones, only SENE (the combined NEMA/Boston, SEMA and Rhode Island Load Zones) is relevant for the tenth 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 2019-2020 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 2019-2020 CAPACITY COMMITMENT PERIOD.

A: Resource availability is modeled in the calculation of the ICR-Related Values. Availability modeling reflects the projected scheduled maintenance and forced outages of capacity resources. 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 ("GADS"). If the individual resource has not been operational for a total of five years, then NERC class average data is also 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 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 2010 through 2014. 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 2019-2020 CAPACITY COMMITMENT PERIOD.

A: The assumed N-1 and N-1-1 transmission import transfer capabilities used to calculate the SENE Capacity Zone Local Sourcing Requirement are shown in the table below.

Table 8 – Internal Transmission Import Capabilities (MW)[10]

Capacity Zone	N-1	N-1-1
SENE	5,700	4,600

Q: PLEASE DISCUSS THE ISO'S ASSUMPTIONS REGARDING THE ACTIONS OF OPERATING PROCEDURE NO. 4 IN DEVELOPING THE ICR-RELATED VALUES FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD.

A: In the FCM, 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 in developing the Installed Capacity Requirement and related values. These all constitute actions that system operators invoke under Operating Procedure No. 4 in real time to balance system demand with supply under expected 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

[10] In addition, the indicative Maximum Capacity Limit calculation to determine if NNE would be modeled as a Capacity Zone used a value of 2,675 MW for the export transmission capability of the North-South Interface.

Operating Procedure No. 13, Standards for Voltage Reduction and Load Shedding Capability ("Operating Procedure No. 13"). 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 442 MW for June through September 2019 and 321 MW for October 2019 through May 2020.

Real-Time Demand Response Resources and Real-Time Emergency Generation Resources are modeled as capacity resources with an expected availability factor calculated as previously described.

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 assumptions. 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 also modeled in the tie benefits study, the results of which are used as an input in the Installed Capacity Requirement, Local Resource Adequacy Requirement and Maximum Capacity Limits 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 10 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 it 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 2019-2020 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 2019-2020 Capacity Commitment Period assume total tie benefits of 1,990 MW based on the results of the tie benefits study for that Capacity Commitment Period. A breakdown of this total value is as follows: 975 MW from Quebec over the Phase II interconnection, 142 MW from Quebec over the Highgate interconnection, 519 MW from New Brunswick (Maritimes) over the New Brunswick interconnections, and 354 MW from New York over the AC interconnections.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR THE TENTH FCA THE SAME AS THE METHODOLOGY USED FOR THE PREVIOUS FCA?

A: Yes. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for the tenth FCA is the same methodology used to calculate the tie benefits used in the Installed Capacity Requirement for the ninth FCA. 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 a similar probabilistic calculation methodology using the GE MARS program 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 TOTAL AND INDIVIDUAL CONTROL AREA TIE BENEFITS.

A: The tie benefits study for the 2019-2020 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 the adjustment noted above for capacity imports and changes in import capability of the interconnections with neighboring Control Areas.

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: PLEASE EXPLAIN THE METHODOLOGY USED TO CALCULATE TIE BENEFITS FOR INDIVIDUAL INTERCONNECTIONS.

A: The methodology for calculating tie benefits for individual interconnections is a direct extension of the calculation methodology specified in Section III.12.9.3 of the Tariff for calculating tie benefits at the system-wide level and for each Control Area to the calculation of tie benefits for individual interconnections.

Under the methodology, tie benefits are calculated for each interconnection state between New England and the target interconnection, or group of interconnections, and the tie benefit value for the interconnection or group of interconnections is the simple average of the tie benefits calculated from all possible interconnection states. An adjustment is then applied to the calculation in the event the sum of the tie benefits calculations for all individual interconnections or groups of interconnections is different than the associated Control Area's tie benefits.

The expected tie benefits contribution from each interconnection or group of interconnections is calculated by averaging the results of the probabilistic simulations that represent the contribution of the targeted interconnection or group of interconnections under different modeling states. Each state represents a different interconnection scenario for New England and the interconnections with neighboring Control Areas which, when averaged, show the relative contribution of the target interconnection or group of interconnections to New England's tie benefits.

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 2019-2020 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 2015, 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 2019-2020 Installed Capacity Requirement filed herewith, the ISO used the transfer capability values from its most recent transfer capability analyses.

Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS INCLUDED AS AN OFFSET TO THE INSTALLED CAPACITY REQUIREMENT AND RESOURCE ADEQUACY BASED REQUIREMENTS FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD.

A: As noted earlier, the total tie benefits assumption was obtained from the results of a probabilistic study which assumes that New England and the three directly interconnected neighboring Control Areas of New Brunswick, New York and Quebec are at no more or less than their reliability criterion of one disconnection of firm load in 10 years, enforced as 0.1 days per year. A total of 1,990 MW of tie benefits are used as an offset to the Installed Capacity Requirement calculations for the 2019-2020 Capacity Commitment Period. This tie benefits value is also utilized in the calculation of the Local Resource Adequacy Requirements and Maximum Capacity Limits. The breakdown of this value by Control Area is as follows: 519 MW from New Brunswick over the New Brunswick interconnections, 354 MW from New York over the New York AC transmission interface and 975 MW from Quebec over the Phase I/II HVDC Transmission Facilities and 142 MW from Quebec over the Highgate interconnection. 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.

III. LOCAL SOURCING REQUIREMENT

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 Non-Price 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 2019-2020 CAPACITY COMMITMENT PERIOD?

A: After applying the import-constrained Capacity Zone objective criteria testing, it was determined that, for the 2019-2020 Capacity Commitment Period, 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 LOCAL SOURCING REQUIREMENT

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

A: The methodology for calculating Local Sourcing Requirements 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 the tariff language reflected in 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 REQUIREMENTS.

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, is achieved. If a zone has insufficient capacity, capacity would be shifted into that zone. Shifting capacity, however, may lead to skewed results, as capacity is not homogeneous. For example, one megawatt of capacity from a nuclear plant is not necessarily the same as one megawatt of capacity from a wind turbine. Consequently, in order to model the effect of shifting "generic" capacity, firm load is shifted. Specifically, as one megawatt of load is added to an import-constrained zone, a megawatt of load is subtracted from the rest of New England, thus keeping the entire system load constant. If a zone has insufficient capacity, load is shifted out of that import-constrained zone. This process continues until the

LOLE of the New England Control Area is equal to 0.105 days per year. At this point, if additional capacity were to be shifted out of the zone (or additional load were added), the LOLE criterion would not be met.

The Local Resource Adequacy Requirement is calculated using the value of shifted load and the existing resources in the zone, including any proxy units that were added as a result of the total system not meeting the LOLE criteria. The load that was shifted must be subtracted from the total resources (including proxy units) to determine the minimum amount of resources that are required in that zone. Before the shifted load is subtracted, it is first converted to equivalent capacity by using the average resource-unavailability rate in the zone. Thus, the Local Resource Adequacy Requirement is calculated as the existing resources in the zone, plus proxy units in the zone, minus the unavailability-adjusted, load-shift amount.

As this load shift test is being performed over a transmission interface internal to the New England Control Area, an allowance for transmission-related LOLE must be applied. This allowance is 0.005 days per year and is only applied when determining the Local Resource Adequacy Requirements of a zone. An LOLE of 0.105 days per year is the point at which it becomes clear that the remaining resources within the zone under study are becoming insufficient. Further reduction in local sources would cause the LOLE in New England to rapidly increase above the criterion.

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

A: The Transmission Security Analysis is a deterministic reliability screen of an import-constrained area and is a basic security review set out in Section 3 of Planning Procedure No. 3 and in Section 5.4 of NPCC's Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System.[11] 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 System Operations 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.

[11] Available at https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf.

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

A: There are three differences between the assumptions relied upon for the Transmission Security Analysis and the assumptions relied upon for determining Local Resource Adequacy Requirements. The first difference relates to the load forecast assumption. Resource adequacy analyses (*i.e.*, the analysis performed in determining the Installed Capacity Requirement and Local Resource Adequacy Requirements) are performed using the full probability distribution of load variations due to weather uncertainty. For the purpose of performing deterministic Transmission Security Analyses, 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 Demand and Real-Time Emergency Generator resources, no Operating Procedure No. 4 actions are included in the calculation of Transmission Security Analysis Requirements.

Q: PLEASE DESCRIBE THE LOCAL RESOURCE ADEQUACY REQUIREMENTS, TRANSMISSION SECURITY ANALYSIS REQUIREMENTS AND THE LOCAL SOURCING REQUIREMENTS FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD.

A: For the 2019-2020 Capacity Commitment Period, Local Resource Adequacy Requirement, Transmission Security Analysis Requirement and the Local Sourcing Requirement for the SENE Capacity Zone are as follows:

Table 10 – Capacity Zone Requirements for the 2019-2020 Capacity Commitment Period (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	10,028	9,584	10,028

IV. MAXIMUM CAPACITY LIMIT

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT?

A: The Maximum Capacity Limit is the maximum amount of capacity that can be procured in an export-constrained Capacity Zone 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 2019-2020 CAPACITY COMMITMENT PERIOD?

A: It was determined that there are no export-constrained Capacity Zones for the 2019-2020 Capacity Commitment Period including the NNE zone, for which a potential Capacity Zone boundary was filed with the Commission on April 6, 2015.[12] When examining the export-constrained Capacity Zone objective criteria for NNE, the indicative Maximum Capacity Limit of 8,830 MW was determined to be greater than the sum of existing capacity and new capacity, electrically located in NNE, that could qualify as capacity resources for the 2019-2020 Capacity Commitment Period. Therefore, NNE will not be modeled as a separate Capacity Zone for the tenth FCA.

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

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[12] The FERC filing identifying SENE and NNE as potential new Capacity Zone boundaries is available at: http://www.iso-ne.com/static-assets/documents/2015/04/er15-___-000_identification_of_potential_new_capacity_zone_boundaries.pdf

[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 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.").

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.

Q: WHAT ARE THE HQICC VALUES FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD?

A: The HQICC values are 975 MW for every month of the 2019-2020 Capacity Commitment Period.

VI. DEMAND CURVE VALUES

Q: WHAT DETERMINES THE CAPACITY REQUIREMENT VALUES FOR THE DEMAND CURVE?

A: Section III.13.2.2 of the Tariff determines that the Demand Curve Values are those calculated (net of HQICCs) at 1-in-5 LOLE and 1-in-87 LOLE.

Q: WHAT ARE THE CAPACITY REQUIRMENT VALUES CALCULATED BY THE ISO FOR THE DEMAND CURVE FOR THE PURPOSES OF CONDUCTING THE TENTH FCA?

A: The 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the Demand Curve are 33,076 MW and 37,053 MW, respectively.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/10/15

Stephen J. Rourke

Executed on 11/10/15

Peter K. Wong

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