December 1, 2016

**VIA ELECTRONIC FILING**

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

Re: *ISO New England Inc. and New England Power Pool*, Docket No. ER17-___-000, Filing of Installed Capacity Requirements, Hydro-Quebec Interconnection Capability Credits and Related Values for 2017-2018, 2018-2019 and 2019-2020 Annual Reconfiguration Auctions

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool ("NEPOOL") Participants Committee, (together, the "Filing Parties"),[2] hereby electronically submits to the Federal Energy Regulatory Commission ("Commission")[3] this transmittal letter and related materials, which identify the Installed Capacity Requirements, Local Sourcing Requirements, Maximum Capacity Limits,[4] Hydro Quebec Interconnection Capability Credits ("HQICCs"), and capacity requirement values

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[1] 16 U.S.C. § 824d (2013).

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

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

[4] As explained in Section V of this filing letter, Maximum Capacity Limits were not calculated for ARA 2 for the 2018-2019 Capacity Commitment Period or ARA 1 for the 2019-2020 Capacity Commitment Period because Maximum Capacity Limits were not calculated for the 2018-2019 Capacity Commitment Period's Forward Capacity Auction ("FCA") or the 2019-2020 Capacity Commitment Period's FCA.

for the System-Wide Capacity Demand Curves ("Demand Curve Values")[5] (collectively, the "ICR-Related Values") for (1) the third annual reconfiguration auction for the 2017-2018 Capacity Commitment Period ("ARA 3 for the 2017-2018 Capacity Commitment Period"), (2) the second annual reconfiguration auction for the 2018-2019 Capacity Commitment Period ("ARA 2 for the 2018-2019 Capacity Commitment Period), and (3) the first annual reconfiguration auction for the 2019-2020 Capacity Commitment Period ("ARA 1 for the 2019-2020 Capacity Commitment Period").[6] Collectively, ARA 3 for the 2017-2018 Capacity Commitment Period, ARA 2 for the 2018-2019 Capacity Commitment Period, and ARA 1 for the 2019-2020 Capacity Commitment Period are referred to herein as the "ARAs." The joint testimony of Ms. Carissa Sedlacek and Ms. Maria Scibelli (the "Sedlacek-Scibelli Testimony"), which is sponsored solely by the ISO, is included in support of this submittal.

The ICR-Related Values for the ARAs are described in detail in Sections IV-VII of this transmittal letter. ARA 3 for the 2017-2018 Capacity Commitment Period is to be held on March 1, 2017, ARA 2 for the 2018-2019 Capacity Commitment Period is to be held on August 1, 2017, and ARA 1 for the 2019-2020 Capacity Commitment Period is to be held on June 5, 2017. The Filing Parties are submitting the ICR-Related Values at least 90 days prior to the annual reconfiguration auctions. Because these values were considered together in the stakeholder process, the Filing Parties submit them together for Commission acceptance.

In accordance with the Code of Federal Regulations, the Filing Parties request that the Commission accept the values submitted for the ARAs in this filing, effective January 30, 2017, which is 60 days from the filing date.[7]

## I. 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

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[5] Capacity requirement values for the System-Wide Capacity Demand Curve are calculated starting with the Forward Capacity Auction ("FCA") for the 2018-2019 Capacity Commitment Period. Accordingly, the ISO calculated Demand Curve Values for ARA 2 for the 2018-2019 Capacity Commitment Period and ARA 1 for the 2019-2020 Capacity Commitment Period.

[6] The 2017-2018 Capacity Commitment Period runs from June 1, 2017 to May 31, 2018, the 2018-2019 Capacity Commitment Period runs from June 1, 2018 to May 31, 2019, and the 2019-2020 Capacity Commitment Period runs from June 1, 2019 to May 31, 2020.

[7] 18 C.F.R. § 35.3(a)(1) (2014).

reliability standards established by the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and has grown to include more than 450 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and merchant transmission providers. Pursuant to revised governance provisions accepted by the Commission,[8] the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, Transmission Operating Agreement (TOA) and the Market Participant Services Agreement included in the Tariff."

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

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

And to NEPOOL as follows:

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## II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values 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 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]

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

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

[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).

[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)).

## III. BACKGROUND

Pursuant to Section III.13 of the Tariff, the ISO administers the FCA for a Capacity Commitment Period to procure capacity needed in the New England Control Area for that Capacity Commitment Period. Subsequent to the FCA, the ISO administers reconfiguration auctions. The ISO is preparing to conduct ARA 3 for the 2017-2018 Capacity Commitment Period, ARA 2 for the 2018-2019 Capacity Commitment Period, and ARA 1 for the 2019-2020 Capacity Commitment Period. The ISO anticipates conducting these ARAs in March, August and June of 2017, respectively. In this filing, the Filing Parties are submitting updated ICR-Related Values, which are key inputs in each annual reconfiguration auction.

The ISO uses the reconfiguration auction process: (1) to balance changes in the amount of the ICR-Related Values that must be procured for the Capacity Commitment Period due to changes in system conditions that have occurred since the calculation of the Installed Capacity Requirement for that Capacity Commitment Period's FCA; and (2) to provide Market Participants with Qualified Capacity that is not already subject to a Capacity Supply Obligation the opportunity to acquire an obligation for a Capacity Commitment Period.

The values for the Installed Capacity Requirements filed herewith have been calculated using the same methodologies that were used in calculating the Installed Capacity Requirements for the annual reconfiguration auctions conducted in 2016. As in past years, the ISO developed the ICR-Related Values with stakeholder input, including NEPOOL participants and representatives of the New England states,[16] which is provided in part through the NEPOOL committee processes through review by the Load Forecast Committee, PSPC, Reliability Committee and Participants Committee. All of the load and resource assumptions needed for the General Electric Multi-Area Reliability Simulation ("GE MARS") model used to calculate the ICR-Related Values were reviewed by the PSPC, a subcommittee of the Reliability Committee.

As in previous years, the values for this year's filing are based on assumptions relating to expected system conditions for each 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. Section VIII of this transmittal letter describes each of those components. With the

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[16] In 2007 the New England States Committee on Electricity ("NESCOE") was formed. Among other responsibilities, NESCOE is responsible for providing feedback on the proposed Installed Capacity Requirement value at the relevant Power Supply Planning Committee ("PSPC"), Reliability Committee and Participants Committee meetings, and was in attendance for the meetings at which the ICR-Related Values filed herewith were discussed.

exception of a slight change in the methodology used to reflect the photovoltaic ("PV") forecast as a reduction in the load forecast, the methodologies determining the load and resource assumptions were the same as those used in calculating the Installed Capacity Requirement for the FCAs for each of the relevant Capacity Commitment Periods.[17]

## IV. INSTALLED CAPACITY REQUIREMENTS

The Installed Capacity Requirement is a measure of the installed capacity 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. 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 (an 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.

### *Proposed Installed Capacity Requirements*

For ARA 3 for the 2017-2018 Capacity Commitment Period, the Filing Parties propose an Installed Capacity Requirement value of 34,246 MW. The 34,246 MW Installed Capacity Requirement value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 1,108 MW per month.[18] Thus, the net Installed Capacity Requirement for ARA 3 for the 2017-2018 Capacity Commitment Period is 33,138 MW.[19]

For ARA 2 for the 2018-2019 Capacity Commitment Period, the Filing Parties propose an Installed Capacity Requirement value of 34,374 MW. The 34,374 MW Installed Capacity Requirement value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 953 MW per

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[17] *See* Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2017-2018 Capability Year, Docket No. ER14-328-000 (filed Nov. 5, 2013); 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 (filed Nov. 4, 2014). Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2019-2020 Capacity Commitment Period; Docket No. ER16-307-000 (filed Nov. 10, 2015).

[18] The HQICC is a monthly value.

[19] Sedlacek-Scibelli Testimony at 12.

month. Thus, the net Installed Capacity Requirement for ARA 2 for the 2018-2019 Capacity Commitment Period is 33,421 MW.[20]

For ARA1 for the 2019-2020 Capacity Commitment Period, the Filing Parties propose an Installed Capacity Requirement value of 34,730 MW. The 34,730 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to the HQICC value of 975 MW per month that are allocated to the Interconnection Rights Holders. Thus, after deducting the HQICC value, the net Installed Capacity Requirement for ARA 1 for the 2019-2020 Capacity Commitment Period is 33,755 MW.[21]

## V. LOCAL SOURCING REQUIREMENTS AND MAXIMUM CAPACITY LIMITS

Under Section III.12 of the Tariff, the ISO calculates Local Sourcing Requirements and Maximum Capacity Limits. A Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone. A Maximum Capacity Limit is the maximum amount of capacity that is electrically located in an export-constrained Capacity Zone used to meet the Installed Capacity Requirement. The general purpose of Local Sourcing Requirements and Maximum Capacity Limits is to provide that capacity resources, when considered in combination with the transfer capability of the transmission system, are electrically distributed within the New England Control Area in a manner that ensures that the minimum amount of resources procured in an auction will meet NPCC's and Section III.12 of the Tariff's one day in ten years (0.1 days per year) disconnection of firm load resource adequacy planning criterion and, in the case of Local Sourcing Requirements, in a manner that also meets transmission security needs.

Pursuant to Section III.13.4.1 of the Tariff, Capacity Zones designated for each FCA must be held constant for the relevant ARAs for the associated Capacity Commitment Period. Accordingly, the ISO calculated Local Sourcing Requirements and Maximum Capacity Limits as described below.

### *Proposed Local Sourcing Requirements and Maximum Capacity Limits for the ARAs*

For ARA 3 for the 2017-208 Capacity Commitment Period, the Local Sourcing Requirements for the Connecticut and Northeast Massachusetts ("NEMA")/Boston import-constrained Capacity Zones are 7,029 MW and 3,361 MW, respectively. The Maximum Capacity Limit for the Maine export-constrained Capacity Zone is 4,295 MW.

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[20] Sedlacek-Scibelli Testimony at 12.

[21] *Id.* at 12-13.

For ARA 2 for the 2018-2019 Capacity Commitment Period: the Local Sourcing Requirement for the Connecticut Capacity Zone is 7,078 MW, the Local Sourcing Requirement for the NEMA/Boston Capacity Zones is 3,445 MW, and the Local Sourcing Requirement for the Southeast Massachusetts ("SEMA")/Rhode Island Capacity Zone is 6,804 MW. No export-constrained zones were modeled for the 2018-2019 Capacity Commitment Period FCA and, accordingly, Maximum Capacity Limits were not calculated for the 2018-2019 Capacity Commitment Period FCA or ARA 2 for the 2018-2019 Capacity Commitment Period.

For ARA 1 for the 2019-2020 Capacity Commitment Period, the Local Sourcing Requirement for the Southeastern New England ("SENE") Capacity Zone is 9,637 MW.[22] No export-constrained zones were modeled for the 2019-2020 Capacity Commitment Period FCA and, accordingly, Maximum Capacity Limits were not calculated for the 2019-2020 Capacity Commitment Period FCA or ARA 1 for the 2019-2020 Capacity Commitment Period.

## VI. HQICCs

HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are the entities that pay for and hold certain rights over the Hydro-Quebec ("HQ") Interconnection. For ARA 3 for the 2017-2018 Capacity Commitment Period, the ISO used 1,108 MW of HQICCs for each month in determining the Installed Capacity Requirement for the 2017-2018 Capacity Commitment Period. The HQICC values used for the calculation of the Installed Capacity Requirement for ARA 2 for the 2018-2019 Capacity Commitment Period, and ARA 1 for the 2019-2020 Capacity Commitment Period are the same values (953 MW and 975 MW, respectively) used in the FCAs for those Capacity Commitment Periods, which were approved by the Commission.[23]

## VII. DEMAND CURVE VALUES

In the FCA for the 2018-2019 Capacity Commitment Period and the FCA for the 2019-2020 Capacity Commitment Period, System-Wide Capacity Demand Curves were used to procure needed capacity. Accordingly, the ISO calculated the Demand Curve Values for ARA 2 for the 2018-2019 Capacity Commitment Period and ARA 1 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, capacity requirements for the Demand Curve have been calculated using the same methodology as that

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[22] The SENE Capacity Zone includes the SEMA, Rhode Island and NEMA/Boston Load Zones.

[23] *ISO New England Inc.*, 150 FERC ¶ 61,003 (2015); *ISO New England Inc.*, 154 FERC ¶ 61,008 (2016).

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 1-in-5 (0.200) LOLE and 1-in-87 (0.011) LOLE.

The 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values associated with the System-Wide Capacity Demand Curve for ARA 2 for the 2018-2019 Capacity Commitment Period are 32,395 MW and 36,159 MW, respectively. The 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values associated with the System-Wide Capacity Demand Curve for ARA 1 for the 2019-2020 Capacity Commitment Period are 32,714 MW and 36,526 MW, respectively.

## VIII. DEVELOPMENT OF THE ICR-RELATED VALUES

The calculation methodology used to develop the ICR-Related Values for the ARAs is the same as that used to calculate the values for the corresponding 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 Periods. 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.

With the exception of a slight change in the methodology used to reflect the photovoltaic ("PV") forecast as a reduction in the load forecast, the methodology used to develop the assumptions is generally the same as that used to calculate the Installed Capacity Requirement and related values for the FCAs. Most of the modeling assumptions have been updated to reflect changed system conditions since the development of the Installed Capacity Requirement and related values for the applicable FCAs.

### A. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2017-2018, 2018-2019 and 2019-2020 Capacity Commitment Periods are major inputs into the calculation of the ICR-Related Values, [24] and the forecasted peak loads for the individual Capacity Zones are used to develop the associated Local Sourcing Requirements and Maximum Capacity Limits.[25] For the purpose of calculating the ICR-Related Values, the ISO used the forecast published in the

[24] The forecasted peak loads for the New England Control Area are shown in the Sedlacek-Scibelli Testimony at 15.

[25] The forecasted peak loads for each of the relevant Capacity Zones are shown in the Sedlacek-Scibelli Testimony at 16.

2016-2025 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2016 ("2016 CELT Report").[26] The 2016 CELT Report load forecast was developed by the ISO using the same methodology that the ISO has used for determining load forecasts in previous years.[27] This methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee.[28]

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 given the probability of occurrence associated with that load level.

Similar to last year, the ICR-Related Values for the ARAs reflect a PV forecast. This year, there is a slight modification in the methodology used to reflect the PV forecast in the calculation of the ICR-Related Values. In order to reflect the 2016 PV forecast in the calculation of the ICR-Related Values for the ARAs, the ISO categorized PV facilities into three types: (1) PV facilities that participate as resources in the FCM and that are modeled for the Capacity Commitment Period of interest if they qualify to participate in that Capacity Commitment Period; (2) PV facilities that do not participate in the FCM but participate in the energy market as Settlement Only Resources; and (3) in-service behind-the-meter PV facilities and behind-the-meter PV facilities forecasted to be installed prior to the Capacity Commitment Period of interest, which reduce system load and are not part of any ISO markets ("BTM PV").[29] In order to estimate the expected output from these future installations during summer peak load conditions, the ISO used publically available state PV profiles from four years of historical data (2012-2015). These were developed from production data available from more than 1,200 currently installed individual PV sites throughout New England. These profiles were used as the basis for an Estimated Summer Seasonal Peak Load Reduction value (% of BTM nameplate rating) of 38.2% for the 2017-2018 Capacity Commitment Period, 37.3% for the 2018-2019 Capacity Commitment Period, and 36.7% for the 2019-2020 Capacity Commitment Period. The percent of the BTM PV nameplate values reflect the load reduction capability of the BTM PV resources at the time of the peaks.

In addition, because the 2016 PV forecast represents end-of-year forecast values, a

[26] Sedlacek-Scibelli Testimony at 14.

[27] *Id.*

[28] The methodology is reviewed periodically and updated when deemed necessary in consultation with the Load Forecast Committee.

[29] Sedlacek-Scibelli Testimony at 17.

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.

Last year, in the calculations of the ICR-Related Values for the ARAs that were conducted in 2016, BTM PV was further subdivided into two subcategories, behind-the-meter PV embedded in load ("BTMEL") and behind-the-meter PV not embedded in load ("BTMNEL"). BTMNEL was then reflected in the calculations of the ICR and related values. Unlike last year, in the 2016 PV forecast, full reconstitution of PV output in both of the BTM subcategories (BTMEL and BTMNEL) was taken into account in the historical loads used to develop the long-term load forecast. This allowed the ISO to combine these two subcategories into one category, *i.e.* BTM PV.[30] Thus, the forecasted amount of BTM PV was deducted from the load forecast used to calculate the ICR-Related Values for the ARAs.[31]

### B. Resource Capacity Ratings

The ICR-Related Values submitted in this filing are based on the latest available Existing Capacity Resource dataset for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Periods, at the time of the calculation of the ICR-Related Values. Resources that have cleared FCAs, annual bilateral transactions and/or previous annual reconfiguration auctions (*i.e.* resources that have acquired Capacity Supply Obligations) are included in the set of Existing Capacity Resources used for the calculation of the ICR-Related Values for each of the ARAs. Resource additions, beyond those classified as Existing Capacity Resources, are not assumed in the calculation of the ICR-Related Values for the ARAs because there is no certainty that qualified new resources will clear the annual reconfiguration auction and obtain a Capacity Supply Obligation. Similarly, resource attritions (*i.e.* resources that Market Participants are seeking to retire or de-list) are not assumed in the calculation of the ICR-Related Values for the ARAs. Rather, only Existing Capacity Resources which have submitted and cleared a de-list bid or submitted a Non-Price Retirement Request and that are not expected to acquire a Capacity Supply Obligation in the annual reconfiguration auction have been excluded in the calculation of the ICR-Related Values for the ARAs. In addition, resources no longer in physical operation were also excluded from the set of resources used to calculate the ICR-Related Values for the

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[30] *Id*.

[31] The monthly values of the PV forecast for the 2017-2018 Capacity Commitment Period, the 2018-2019 Capacity Commitment Period, and the 2019-2020 Capacity Commitment Period are included in Table 3 of the Sedlacek-Scibelli Testimony at 19.

ARAs.[32]

### C. Resource Availability

The ICR-Related Values reflect resource availability assumptions based on historical scheduled maintenance and forced outages of capacity resources. For generating resources, scheduled maintenance assumptions are based on each individual resource's most recent historical five-year average of scheduled maintenance.[33] If the individual resource has not been operational for five years, then NERC class average data is used to substitute for the missing annual data. An individual 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 for less than five years, the NERC class average data for the same class of resource type is used to substitute for the missing annual data.[34]

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 the energy limitations are already incorporated into the resource ratings.[35]

In the Installed Capacity Requirement calculations, performance for the Real-Time Demand Response Resource and Real-Time Emergency Generation Resource categories is measured by actual response during performance audits and response during ISO New England Operating Procedure No. 4, Action During a Capacity Deficiency ("Operating Procedure No. 4"), events that occurred during the summers and winters of 2011 through 2015. 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 to be 100% available.[36]

### D. Other Assumptions

In the development of the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit and Demand Curves Values, assumed emergency

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[32] The Sedlacek-Scibelli Testimony provides the total MWs for each type of capacity resource assumed in the ICR-Related Values calculations for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Period. *See* Sedlacek-Sicbelli Testimony at 21-23.

[33] *Id*. at 24.

[34] *Id.*

[35] *Id.*

[36] *Id* at 24-25.

assistance (tie benefits) available from neighboring Control Areas and the load reduction from implementation of 5% voltage reductions are used. These all constitute actions that system operators invoke under Operating Procedure No. 4 in real time to balance system demand with supply under expected capacity shortage conditions. The amount of load relief assumed obtainable from invoking 5% voltage reductions is based on the performance standard established in ISO New England Operating Procedure No. 13, Standards for Voltage Reduction and Load Shedding Capability.[37]

Tie benefits from neighboring Control Areas reduce the Installed Capacity Requirement and the need to buy capacity to meet the New England resource adequacy criterion. Tie benefits reflect the amount of emergency assistance that is assumed to be available to New England from its neighboring Control Areas in the event of a capacity shortage in New England, without jeopardizing reliability in New England or its neighboring Control Areas.

Under Section III.12.9.2.4(a) of the Tariff, one factor in the calculation of tie benefits is the transfer capability of the interconnections for which tie benefits are calculated. In the first half of 2016, the transfer limits 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.[38] The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for ARA 3 of the 2017-2018 Capacity Commitment Period's Installed Capacity Requirement, for both internal and external transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.[39] Pursuant to Section III.12.9.2 of the Tariff, tie benefits for ARA 3 for the 2017-2018 Capacity Commitment Period were calculated using "at criterion" modeling assumptions. Using this methodology, a total of 1,875 MW of tie benefits was utilized in the calculation of the ICR-Related Values for ARA 3 for the 2017-2018 Capacity Commitment Period based on the results of the tie benefits study. A breakdown of this total value is as follows: 1,108 MW from Quebec over the Phase II interconnection, 71 MW from

[37] Sedlacek-Scibelli Testimony at 26.

[38] The ISO established transfer capability values for the following interconnections: 700 MW for the New Brunswick interconnections; 1,400 MW for the HQ Phase I/II HVDC Transmission Facilities; and 200 MW for the Highgate interconnection. The ISO also determined that there was no available transfer capability over the Cross Sound Cable for tie benefits. Finally, the ISO calculated a transfer capability for the New York-New England AC interconnections as a group, because the transfer capability of these interconnections is interdependent on the transfer capability of the other interconnections in the group. For the New York-New England AC interconnections, the transfer capability was determined to be 1,400 MW. *See* Sedlacek-Scibelli Testimony at 31.

[39] *Id*.

Quebec over the Highgate interconnection, 224 MW from New Brunswick (Maritimes) over the New Brunswick ties and 472 MW from New York over the AC ties.[40]

Pursuant to Section III.12.9.1.1 of the Tariff, the Installed Capacity Requirement calculation for ARA 2 for the 2018-2019 Capacity Commitment Period assumes the same level of tie benefits calculated for the corresponding FCA of 1,970 MW total tie benefits.[41] A breakdown of this total value is as follows: 953 MW from Quebec over the Phase II interconnection, 148 MW from Quebec over the Highgate interconnection, 523 MW from New Brunswick (Maritimes) over the New Brunswick ties and 346 MW from New York over the AC ties.

Pursuant to Section III.12.9.1.1 of the Tariff, the Installed Capacity Requirement calculation for ARA 1 for the 2019-2020 Capacity Commitment Period also assumes the same level of tie benefits calculated for the corresponding FCA of 1,990 MW total tie benefits. 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 ties and 354 MW from New York over the AC ties.

## IX. DEVELOPMENT OF LOCAL SOURCING REQUIREMENTS AND MAXIMUM CAPACITY LIMITS

In the FCM, the ISO must also calculate Local Sourcing Requirements and Maximum Capacity Limits to be used, if necessary, in each FCA and reconfiguration auction. A Local Sourcing Requirement is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone, and 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. Local Sourcing Requirements and Maximum Capacity Limits help to ensure that capacity resources are distributed geographically within the New England Control Area in a manner that ensures compliance with reliability criteria.

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[40] Sedlacek-Scibelli at 32, Table 11.

[41] Section III.12.9.1.1 of the Tariff requires that, for the first and second annual reconfiguration auctions for a Capacity Commitment Period, tie benefits calculated for the associated FCA be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Demand Curve Values, adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in import capacity resources using the methodologies in Section III.12.9.6 of the Tariff. As addressed in the Sedlacek-Scibelli Testimony at 30, there have been no adjustments made to the tie benefits values calculated for the FCAs for 2018-2019 and 2019-2020 because there have been no changes in import capability of the interconnections with neighboring Control Areas or in import capacity resources that would result in changes to the tie benefits assumptions.

The ISO calculates the Local Sourcing Requirement and Maximum Capacity Limit under Section III.12.2 of the Tariff. The Local Sourcing Requirement is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy Requirement or (ii) the Transmission Security Analysis Requirement.[42]

The Local Resource Adequacy Requirement is 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 is calculated with "at criteria" system conditions. The calculation of the Transmission Security Analysis Requirement is addressed in Section III.12.2.1 of the Tariff. The Transmission Security Analysis is a deterministic reliability analysis of an import-constrained area. It uses a series of transmission load flow studies aimed at determining the performance of the transmission system under future stressed conditions and develops a resource requirement sufficient to allow the system to operate through the stressed situation.[43]

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 the Local Resource Adequacy Requirement. However, due to the deterministic 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 Local Resource Adequacy Requirement. These differences relate to the manner in which load forecast data, forced outage rates for certain resource types, and Operating Procedure No. 4 action events are utilized in the Transmission Security Analysis. These differences are described in more detail in the Sedlacek-Scibelli Testimony.[44]

The following tables[45] contain the Local Resource Adequacy Requirement and Transmission Security Analysis Requirement values for the relevant Capacity Zones in each of the Capacity Commitment Periods associated with the ARAs. The tables also show the Local Sourcing Requirement, which as explained above is the higher of the Transmission Security Analysis Requirement or the Local Resource Adequacy Requirement.

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[42] Section III.12.2.1 of the Tariff.

[43] Section III.12.2.1.2(a) of the Tariff. *See also* Sedlacek-Scibelli Testimony at 34-35.

[44] *Id.* at 35-36.

[45] All values in the tables are shown in MW.

**ARA 3 for the 2017-2018 Capacity Commitment Period**

| Capacity Zone | Transmission Security Analysis Requirement | Local Resource Adequacy Requirement | Local Sourcing Requirement |
|---|---|---|---|
| Connecticut | 7,029 | 6,909 | 7,029 |
| NEMA/Boston | 3,361 | 2,862 | 3,361 |

**ARA 2 for the 2018-2019 Capacity Commitment Period**

| Capacity Zone | Transmission Security Analysis Requirement | Local Resource Adequacy Requirement | Local Sourcing Requirement |
|---|---|---|---|
| Connecticut | 7,072 | 7,078 | 7,078 |
| NEMA/Boston | 3,445 | 2,932 | 3,445 |
| SEMA/RI | 6,305 | 6,804 | 6,804 |

**ARA 1 for the 2019-2020 Capacity Commitment Period**

| Capacity Zone | Transmission Security Analysis Requirement | Local Resource Adequacy Requirement | Local Sourcing Requirement |
|---|---|---|---|
| SENE | 9,637 | 9,360 | 9,637 |

In addition to the values presented in the tables, the ISO calculated the Maximum Capacity Limit for the Maine Capacity Zone for ARA 3 for the 2017-2018 Capacity Commitment Period. As already mentioned in Section V of this filing letter, the Maximum Capacity Limit is 4,295 MW.

## X. STAKEHOLDER PROCESS

At its October 18, 2016 meeting, the Reliability Committee reviewed and considered the ICR-Related Values for the ARAs. A motion that the Reliability Committee recommend Participants Committee support for the ISO's proposed HQICC values passed by a show of hands with one opposition and no abstentions. A separate motion that the Reliability Committee recommend Participants Committee support for the ISO's proposed Installed Capacity Requirements, Local Sourcing Requirements, Maximum Capacity Limits, and Demand Curve Values passed by a show of hands with one opposition and no abstentions. At its November 4, 2016 meeting, the Participants Committee voted to support the proposed ICR-Related Values as part of its consent agenda, with two oppositions noted.

## XI. REQUESTED EFFECTIVE DATE

The Filing Parties request that the Commission accept the proposed ICR-Related Values for the ARAs to be effective on January 30, 2017.[46]

## XII. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for the ARAs and is made pursuant to Section 205 of the FPA. Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of cost-of-service rates.[47] 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;
- Testimony of Carissa Sedlacek and Maria Scibelli, sponsored solely by the ISO;
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 30, 2017.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at https://www.iso-

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[46] 18 C.F.R. § 35.3.

[47] 18 C.F.R. § 35.13.

ne.com/participate/participant-asset-listings/directory?id=1&type=committee . An electronic copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states 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 the attachment hereto. In accordance with Commission rules and practice, there is no need for the entities identified in the attachment 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 Section XII.

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

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

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

35.13(c)(2) - The ISO does not provide services under other rate schedules that are similar to the sale for resale and transmission services it provides under the ISO 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.

**XIII. CONCLUSION**

The Filing Parties request that the Commission accept the proposed ICR-Related Values and HQICC values reflected in this submission for filing without change to become effective January 30, 2017.

Respectfully submitted,

ISO NEW ENGLAND INC.

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NEW ENGLAND POWER POOL PARTICIPANTS COMMITTEE

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Attachments

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| **ISO New England Inc. and** | **)** | **Docket No. ER17-___-000** |
| **New England Power Pool** | **)** | |

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

## I. BACKGROUND

**Q: WHAT IS THE PURPOSE OF THIS TESTIMONY?**

**A:** This testimony explains the derivation of the Installed Capacity Requirements, Local Sourcing Requirements, Maximum Capacity Limits,[1] Hydro-Quebec Interconnection Capability Credits ("HQICCs") and capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve Values")[2] (collectively, the "ICR-Related Values") for: (1) the third annual reconfiguration auction for the 2017-2018 Capacity Commitment Period ("ARA 3 for the 2017-2018 Capacity Commitment Period"); (2) the second annual reconfiguration auction for the 2018-2019 Capacity Commitment Period ("ARA 2 for the 2018-2019 Capacity Commitment Period); and (3) the first annual reconfiguration auction for the 2019-2020 Capacity Commitment Period ("ARA 1 for the

[1] Maximum Capacity Limits were not calculated for ARA 2 for the 2018-2019 Capacity Commitment Period or ARA 1 for the 2019-2020 Capacity Commitment Period because Maximum Capacity Limits were not calculated for the corresponding Forward Capacity Auctions ("FCAs").

[2] Capacity requirement values for the System-Wide Capacity Demand Curve were calculated for the FCA for the 2018-2019 Capacity Commitment Period and the 2019-2020 Capacity Commitment Period. Accordingly, the ISO calculated Demand Curve Values for ARA 2 for the 2018-2019 Capacity Commitment Period and ARA 1 for the 2019-2020 Capacity Commitment Period.

2019-2020 Capacity Commitment Period").[3] Collectively, ARA 3 for the 2017-2018 Capacity Commitment Period, ARA 2 for the 2018-2019 Capacity Commitment Period, and ARA 1 for the 2019-2020 Capacity Commitment Period are referred to herein as the "ARAs." Our testimony also explains the assumptions used in the calculations of the ICR-Related Values for the ARAs.

**Q: WHAT IS AN ANNUAL RECONFIGURATION AUCTION?**

**A:** An annual reconfiguration auction is conducted as part of the ISO-administered Forward Capacity Market ("FCM"). An annual reconfiguration auction is conducted after the FCA for a Capacity Commitment Period and before the start of that Capacity Commitment Period. The purposes of the reconfiguration auction are: (1) to balance changes in the amount of the ICR-Related Values that must be procured for the Capacity Commitment Period due to changes in system conditions that have occurred since the calculation of the Installed Capacity Requirement for that Capacity Commitment Period's FCA; and (2) to provide Market Participants with Qualified Capacity that is not already subject to a Capacity Supply Obligation the opportunity to acquire an obligation for a Capacity Commitment Period.

**Q: IS THE PROCESS FOR DEVELOPING THE ICR-RELATED VALUES FOR THE ARAs THE SAME AS THAT USED LAST YEAR?**

[3] The 2017-2018 Capacity Commitment Period runs from June 1, 2017 to May 31, 2018, the 2018-2019 Capacity Commitment Period runs from June 1, 2018 to May 31, 2019, and the 2019-2020 Capacity Commitment Period runs from June 1, 2019 to May 31, 2020.

**A:** Yes. The methodology used for the calculations of the ICR-Related Values is the same methodology that was used in 2015 for calculating the Installed Capacity Requirements and related values for the second annual reconfiguration auction for the 2017-2018 Capacity Commitment Period, the first annual reconfiguration auction for the 2018-2019 Capacity Commitment Period, and the 2019-2020 Capacity Commitment Period's FCA. This year, as explained in Section III of this testimony, there is a slight change in the methodology used to include the photovoltaic ("PV") forecast in the load forecast, which is an assumption in the calculation of the ICR-Related Values.

**Q: FOR WHICH IMPORT-CONSTRAINED AND EXPORT-CONSTRAINED CAPACITY ZONES DID THE ISO CALCULATE A LOCAL SOURCING REQUIREMENT OR MAXIMIMUM CAPACITY LIMIT FOR EACH OF THE CAPACITY COMMITMENT PERIODS?**

**A:** Pursuant to Section III.13.4.1 of the Tariff, Capacity Zones designated for each FCA must be held constant for the relevant ARAs for the associated Capacity Commitment Period. Accordingly, using the methodology described in Section III.12.2 of the Tariff, the ISO calculated the following:

- For ARA 3 for the 2017-2018 Capacity Commitment Period: Local Sourcing Requirements for the Connecticut and Northeast Massachusetts ("NEMA")/Boston Capacity Zones, and Maximum Capacity Limit for the Maine Capacity Zone
- For ARA 2 for the 2018-2019 Capacity Commitment Period: Local Sourcing Requirements for the Connecticut, NEMA/Boston Capacity Zones and the

combined Southeast Massachusetts (“SEMA”) and Rhode Island Load Zones which make up the (“SEMA/Rhode Island”) Capacity Zone

- For ARA 1 for the 2019-2020 Capacity Commitment Period: Local Sourcing Requirement for the combined SEMA, Rhode Island and NEMA/Boston Load Zones which make up the Southeastern New England (“SENE”) Capacity Zone

**Q: FOR WHICH ANNUAL RECONFIGURATION AUCTIONS DID THE ISO CALCULATE DEMAND CURVE VALUES?**

**A:** The ISO calculated Demand Curve Values for ARA 2 for the 2018-2019 Capacity Commitment Period and ARA 1 for the 2019-2020 Capacity Commitment Period because system-wide demand curves were used in the FCAs for those Capacity Commitment Periods.

## II. CALCULATION OF THE INSTALLED CAPACITY REQUIREMENT – OVERVIEW

**Q: WHAT IS THE “INSTALLED CAPACITY REQUIREMENT?”**

**A:** The Installed Capacity Requirement is the minimum level of capacity required to meet the reliability requirements of the New England Control Area. These reliability requirements are 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 INSTALLED CAPACITY REQUIREMENTS.**

**A:** The three Installed Capacity Requirements submitted in this filing were established through a single stakeholder process and in accordance with the Installed Capacity Requirements calculation methodology prescribed in Section III.12 of the Tariff. The stakeholder process consisted of discussions with the NEPOOL Load Forecast Committee ("LFC"),[5] the PSPC and the NEPOOL Reliability Committee. These committees review and comment on the ISO's development of load and resource assumptions. The ISO's calculation of the ICR-Related Values for the ARAs was

[4] Available at http://www.iso-ne.com/static-assets/documents/rules_proceds/isone_plan/pp03/pp3_final.pdf

[5] The LFC is a non-voting technical subcommittee under the NEPOOL Reliability Committee that reviews and comments on the development of the annual load forecast for the New England region.

followed by advisory votes from the NEPOOL Reliability Committee and NEPOOL Participants Committee. Both the NEPOOL Reliability Committee and the Participants Committee supported the ICR-Related Values for the ARAs.

Representatives of the six New England States' public utilities regulatory commissions are also invited to attend and participate in the PSPC, Reliability Committee and Participants Committee meetings, and were present for the meetings at which the ICR-Related Values were discussed and considered.

**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 the ICR-Related Values, including appropriate assumptions relating to load, resources, and tie benefits and the resource adequacy related issues surrounding the appropriate incorporation of PV resources from the PV forecast for modeling the expected system conditions. The PSPC reviewed the assumptions relating to the calculation of the ICR-Related Values for the ARAs over the course of five meetings in May, July, August, September, and October 2016.

**Q: PLEASE EXPLAIN THE CALCULATION METHODOLOGY FOR ESTABLISHING THE INSTALLED CAPACITY REQUIREMENTS FOR THE ARAs.**

A: As done for each FCA, the Installed Capacity Requirements for the ARAs were established using the General Electric Multi-Area Reliability Simulation ("GE MARS") program. 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 random combinations of resource capacity and load levels taking into account resource outages. For the Installed Capacity Requirement, the system is considered to be a one bus model, in that the New England transmission system is assumed to have no internal transmission constraints in this simulation. For each hour, the program computes the isolated area capacity available to meet demand based on the expected maintenance and forced outages of the resources and the expected demand. Based on the available capacity, the program determines the probability of loss of load for the system for each hour of the year. After simulating all hours of the year, the program sums the probability of loss of load for each hour to arrive at an annual probability of loss of load value. This value is tested for convergence, which is set to be 5% of the standard deviation of the average of the hourly loss of load values. If the simulation has not converged, it proceeds to another replication of the study year.

Once the program has computed an annual reliability index, if the system is less reliable than the resource-adequacy criterion (*i.e.*, the 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, if needed, 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. 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.

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 load (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: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT ESTABLISHED FOR EACH OF THE ARAs.**

**A:** The proposed Installed Capacity Requirement for ARA 3 for the 2017-2018 Capacity Commitment Period is 34,246 MW. The 34,246 MW Installed Capacity Requirement value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 1,108 MW per month.[6] Thus, the net Installed Capacity Requirement for use in ARA 3 for the 2017-2018 Capacity Commitment Period will be 33,138 MW.

The proposed Installed Capacity Requirement for ARA 2 for the 2018-2019 Capacity Commitment Period is 34,374 MW. The 34,374 MW Installed Capacity Requirement value does not reflect the deduction of the HQICCs that are allocated to the Interconnection Rights Holders, as required by the Tariff. Those HQICCs are 953 MW per month. Thus, the net Installed Capacity Requirement for use in ARA 2 for the 2018-2019 Capacity Commitment Period is 33,421 MW.

The proposed Installed Capacity Requirement for ARA1 for the 2019-2020 Capacity Commitment Period is 34,730 MW. The 34,730 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to the HQICC value of 975 MW per month that are allocated to the Interconnection Rights Holders. Thus,

[6] The HQICC is a monthly value.

after deducting the HQICC value, the net Installed Capacity Requirement for ARA 1 for the 2019-2020 Capacity Commitment Period is 33,755 MW.[7]

## III. THE ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES

**Q: WHAT ARE THE MAIN ASSUMPTIONS UPON WHICH THE ICR-RELATED VALUES FOR THE ARAS ARE BASED?**

**A:** One of the first steps in the process of determining the ICR-Related Values for the ARAs is for the ISO to identify reasonable assumptions relating to expected system conditions for the relevant Capacity Commitment Periods. 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.

[7] A presentation to the Reliability Committee which contains comparison of the proposed Installed Capacity Requirements for the ARAs with the Installed Capacity Requirements for the corresponding FCAs is available at https://www.iso-ne.com/static-assets/documents/2016/10/a6_ara_icr_assumptions_presentation.pdf This presentation also provides details on changes to the assumptions used in the calculation of the ICR-Related Values.

### 1. LOAD FORECAST

**Q: PLEASE DESCRIBE THE SOURCE OF THE FORECASTED LOAD FOR THE ARAs.**

**A:** The forecasted peak loads of the entire New England Control Area for the 2017-2018, 2018-2019 and 2019-2020 Capacity Commitment Periods are major inputs into the calculation of the ICR-Related Values, and the forecasted peak loads for the individual Capacity Zones are used to develop the associated Local Sourcing Requirements and Maximum Capacity Limits. For the purpose of calculating the ICR-Related Values for each of the ARAs, the ISO used the forecast published in the ISO New England 2016-2025 Forecast Report of Capacity, Energy, Loads, And Transmission dated May 1, 2016 ("2016 CELT Report").[8] The 2016 CELT Report load 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 Requirements in previous years.

**Q: PLEASE EXPLAIN HOW THE ISO DERIVED THE 2016 CELT REPORT LOAD FORECAST USED IN DEVELOPING THE ICR-RELATED VALUES.**

**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

[8] 2016 CELT Report (May 2016), available at https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls.

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.

From this weekly peak load forecast distribution, a monthly set of load forecast uncertainty multipliers are developed and applied to a specific historical hourly load profile to provide 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 PROJECTED NEW ENGLAND CONTROL AREA 50/50 PEAK LOADS FOR THE 2017-2018, 2018-2019 AND 2019-2020 CAPACITY COMMITMENT PERIODS.**

**A:** The following table shows the 50/50 peak load forecast (MW) for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Periods as documented in the 2016 CELT Report.

**Table 1 – 50/50 Peak Load Forecast Values for New England (MW)**

| Peak Load Forecast | New England |
|---|---|
| **Capacity Commitment Period** | **50/50** |
| 2017-2018 | 28,788 |
| 2018-2019 | 29,070 |
| 2019-2020 | 29,344 |

**Q: PLEASE DESCRIBE THE PROJECTED 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE RELEVANT CAPACITY ZONES FOR THE 2017-2018, 2018-2019 AND 2019-2020 CAPACITY COMMITMENT PERIODS.**

**A:** The projected 50/50 and 90/10 peak load forecast from the 2016 CELT Report for each relevant Capacity Zone for the applicable Capacity Commitment Period are shown in the table below.

**Table 2 – 50/50 and 90/10 Peak Load Forecast Values for the Applicable Capacity Zones in each Capacity Commitment Period (MW)**

| Peak Load Forecast | NEMA/Boston | | Connecticut | | SEMA/RI | | SENE | | Maine | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Capacity Commitment Period** | **50/50** | **90/10** | **50/50** | **90/10** | **50/50** | **90/10** | **50/50** | **90/10** | **50/50** | **90/10** |
| 2017-2018 | 6,149 | 6,612 | 7,448 | 8,133 | - | - | - | - | 2,135 | 2,283 |
| 2018-2019 | 6,223 | 6,693 | 7,492 | 8,182 | 5,664 | 6,198 | - | - | - | - |
| 2019-2020 | - | - | - | - | - | - | 12,022 | 13,043 | - | - |

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

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

**Q: ARE THERE ANY CHANGES TO THE METHODOLOGY THAT WAS USED TO REFLECT THE PV FORECAST IN THE CALCULATION OF THE ICR-RELATED VALUES LAST YEAR?**

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

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

A: Annually, the ISO, in conjunction with the Distributed Generation Forecast Working Group ("DGFWG") (which includes state agencies responsible for administering the New

England states' policies, incentive programs and tax credits that support PV growth in New England), develops forecasts of future nameplate ratings of PV installations anticipated over the 10-year planning horizon. These forecasts are created for each state based on policy drivers, recent PV growth trends, and discount adjustments designed to represent a degree of uncertainty in future PV commercialization.

In order to estimate the expected output from these future installations during summer peak load conditions, the ISO used publically available state PV profiles from four years of historical data (2012-2015). These were developed from production data available from more than 1,200 currently installed individual PV sites throughout New England. These profiles were used as the basis for an Estimated Summer Seasonal Peak Load Reduction value (% of BTM nameplate rating) of 38.2% for the 2017-2018 Capacity Commitment Period, 37.3% for the 2018-2019 Capacity Commitment Period, and 36.7% for the 2019-2020 Capacity Commitment Period. The percent of the BTM PV nameplate values reflect the load reduction capability of the BTM PV resources at the time of the peaks.

In addition, because the 2016 PV forecast represents end-of-year forecast values, a monthly value representing incremental growth throughout the year was determined by using PV growth trends across the region over the past three years. These values were applied to the annual end-of-year PV forecast values over the forecast horizon to develop the appropriate monthly values. The monthly values of the PV forecast for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Periods shown in Table 3 below are modeled as a load modifier in the GE MARS model within the probabilistic calculations for the ICR-Related Values for each of the ARAs. These values are distributed to sub-areas for the summer reliability hours ending 14:00 through 18:00. All other hours and all non-summer months are considered as zeros. For deterministic analyses, the reference load forecast which is net of BTM PV resources was used. Modeling the PV resources this way effectively reduced the load forecast for each month by the corresponding monthly PV forecast values.

**Table 3 – Monthly Value of BTM PV for the 2017-2018, 2018-2019 and 2019-2020 Capacity Commitment Periods (MW)[9]**

| Month | 2017-2018 | 2018-2019 | 2019-2020 |
|---|---|---|---|
| Jun | 513 | 578 | 628 |
| Jul | 520 | 582 | 632 |
| Aug | 527 | 588 | 636 |
| Sep | 533 | 592 | 640 |
| Oct | 0 | 0 | 0 |
| Nov | 0 | 0 | 0 |
| Dec | 0 | 0 | 0 |
| Jan | 0 | 0 | 0 |
| Feb | 0 | 0 | 0 |
| Mar | 0 | 0 | 0 |
| Apr | 0 | 0 | 0 |
| May | 574 | 625 | 669 |

[9] 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.

### 2. RESOURCE CAPACITY RATINGS

**Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE ICR-RELATED VALUES FOR THE 2017-2018, 2018-2019 AND 2019-2020 CAPACITY COMMITMENT PERIODS.**

**A:** The ICR-Related Values submitted in this filing are based on the latest available Existing Capacity Resource dataset for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Periods, at the time of the calculation of the ICR-Related Values. Resources that have cleared FCAs and/or annual reconfiguration auctions, or acquired an obligation as part of a bilateral transaction (*i.e.* resources that have acquired Capacity Supply Obligations) are included in the set of Existing Capacity Resources used for the calculation of the ICR-Related Values for each of the ARAs. Resources that have retired or are no longer in physical operation were excluded from the set of resources used to calculate the ICR-Related Values.

**Q: WHAT ARE THE RESOURCE CAPACITY VALUES ASSUMED IN THE ICR-RELATED VALUES CALCULATIONS FOR THE 2017-2018, 2018-2019 AND 2019-2020 CAPACITY COMMITMENT PERIODS?**

**A:** The following tables summarize the total MWs for each type of capacity resource assumed in the ICR-Related Values calculations for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Periods.

**Table 4 – Qualified Existing Non-Intermittent Generating Capacity Resources Used in the ICR-Related Values Calculations (MW)**[10]

| Capacity Commitment Period | Summer |
|---|---|
| 2017-2018 | 28,985.779 |
| 2018-2019 | 30,035.784 |
| 2019-2020 | 30,629.984 |

**Table 5 – Qualified Existing Intermittent Generating Capacity Resources Used in the ICR-Related Values Calculations (MW)** [11]

| Capacity Commitment Period | Summer | Winter |
|---|---|---|
| 2017-2018 | 1,095.904 | 1,308.900 |
| 2018-2019 | 1,067.825 | 1,261.896 |
| 2019-2020 | 911.693 | 1,182.144 |

Table 6 shows the Existing Import Capacity Resources assumed in the calculation of the ICR-Related Values for the ARAs.

In the auction, Import Capacity Resources compete for the amount of available Transmission Transfer Capability ("TTC") of an external interface into New England; therefore, the total MW from qualified Existing Import Capacity Resources that are qualified to participate in the ARAs may be higher than the amount of available TTC. For that reason, the values used in ICR-Related Values calculations for the ARAs are derated to reflect: (1) the TTC interface limit of the external interfaces, which was determined after the ISO conducted a review in early 2016; and (2) the amount of TTC

[10] For detailed information relating to the resources assumed in the ICR-Related Values, see the presentation to the Reliability Committee at https://www.iso-ne.com/static-assets/documents/2016/10/a6_ara_icr_assumptions_presentation.pdf.

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

that must be reserved for tie benefits into New England over these external interfaces.[12] Hence, the Existing Import Capacity Resources shown in Table 6 reflect the Qualified Capacity ("QC") values of those resources, derated for TTC and the tie benefits values for the 2017-2018, 2018-2019 and 2019-2020 Capacity Commitment Periods.

**Table 6 – Derated Qualified Existing Import Capacity Resources Used in the ICR-Related Values Calculation (MW)**

| Capacity Commitment Period | Summer |
|---|---|
| 2017-2018 | 1,756 |
| 2018-2019 | 1,730 |
| 2019-2020 | 1,510 |

Table 7 shows the Demand Resources assumed in the calculations of the ICR-Related Values for the ARAs by type of resource. Passive Demand Resources include On-Peak Demand Resources and Seasonal Peak Demand Resources. Active Demand Resources include Real-Time Demand Response ("RTDR")[13] Resources and Real-Time Emergency Generation ("RTEG") Resources.[14]

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[12] Both the TTC of the external interfaces and the amount of tie benefits assumed for each of the Capacity Commitment Periods are detailed in tables later in this testimony.

[13] Starting with the 2018-2019 Capacity Commitment Period, RTDR Resources are designated as Demand Response Capacity Resources in the Tariff.

[14] The ISO has taken steps to address the reversal of the Environmental Protection Agency's ("EPA") rules that allowed RTEG Resources to operate for purposes of emergency demand response. *See* ISO New England Inc., Filing of Request for Limited Waiver, Docket No. ER16-1904-000 (June 9, 2016), granted by the Commission on August 8, 2016 in *ISO New England Inc.*, 156 FERC ¶ 61,096 (2016). As part of these efforts, some RTEG Resources have changed their resource type to RTDR Resources and others have had their Qualified Capacity lowered to zero MW for future Capacity Commitment Periods.

**Table 7 - Existing Demand Resources Used in the ICR-Related Values Calculation (MW)**

| Capacity Commitment Period | On-Peak | Seasonal Peak | RTDR | RTEG | Total |
|---|---|---|---|---|---|
| 2017-2018 | 1,751.727 | 448.252 | 1,009.367 | 1.200 | 3,210.546 |
| 2018-2019 | 1,905.856 | 426.972 | 793.939 | - | 3,126.767 |
| 2019-2020 | 2,092.350 | 508.838 | 498.538 | - | 3,099.726 |

**Q: WHAT ARE THE ASSUMPTIONS RELATING TO RESOURCE ADDITIONS AND ATTRITIONS?**

**A:** Resource additions, beyond those classified as Existing Capacity Resources, are not assumed in the calculation of the ICR-Related Values for the ARAs because there is no certainty that qualified new resources will clear the annual reconfiguration auction and obtain a Capacity Supply Obligation. Similarly, resource attritions (*i.e.* resources that Market Participants are seeking to retire or de-list) are not assumed in the calculation of the ICR-Related Values for the ARAs. Rather, only Existing Capacity Resources which have submitted and cleared a de-list bid or submitted a Non-Price Retirement Request and that therefore are not expected to acquire a Capacity Supply Obligation in the annual reconfiguration auction have been excluded from the calculations of the ICR-Related Values for the ARAs. In addition, resources no longer in physical operation have also been excluded from the set of resources used to calculate the ICR-Related Values for the ARAs.

## 3. RESOURCE AVAILABILITY

**Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS UNDERLYING THE CALCULATIONS OF THE ICR-RELATED VALUES FOR THE ARAs.**

**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 five years, then NERC class average data is used to substitute for the missing annual data. It is assumed that generating resources will not schedule their maintenance outages 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, covering January 2011 through December 2015, from the ISO's database of NERC Generator Availability Database System ("GADS"). If the individual resource has not been operational for five years, then NERC class average data is also used to substitute for the missing annual data. As explained in Section IV of this testimony, 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 with Capacity Supply Obligations are assumed to be 100% available in the models and not based on "nameplate" ratings.

Performance of active Demand Resources in the RTDR and RTEG categories is measured by actual response during performance audits and Operating Procedure No. 4 events that occurred in the summer and winter periods of 2011 through 2015. To calculate historical availability, the actual load curtailed or generation provided during such events is measured against the resources' Capacity Supply Obligations.

Passive 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 to be 100% available.

## 4. OTHER ASSUMPTIONS

**Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION INTERFACE TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR THE ARAs.**

**A:** The assumed N-1 and N-1-1 transmission interface import transfer capabilities for the Connecticut, NEMA/Boston, SEMA/RI and SENE Capacity Zones and the assumed N-1 transmission interface export limit for the Maine Capacity Zone are shown in the tables below for the relevant Capacity Commitment Periods.

**Table 8 – N-1 and N-1-1 Transmission Transfer Capability Limits Used in the ICR-Related Values Calculations (MW)**

| | Connecticut Import (for Connecticut LSR) | | Boston Import (for NEMA/Boston LSR) | | SEMA/RI Import (for SEMA/RI LSR) | | Southeast New England Import (for SENE LSR) | | Maine-New Hampshire (for Maine MCL) |
|---|---|---|---|---|---|---|---|---|---|
| Capacity Commitment Period | N-1 | N-1-1 | N-1 | N-1-1 | N-1 | N-1-1 | N-1 | N-1-1 | N-1 |
| 2017-2018 | 2,950 | 1,750 | 4,850 | 4,175 | - | - | - | - | 1,900 |
| 2018-2019 | 2,950 | 1,750 | 4,850 | 4,175 | 1,280 | 720 | - | - | - |
| 2019-2020 | - | - | - | - | - | - | 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.**

**A:** In the FCM, assumed emergency assistance (tie benefits) available from neighboring Control Areas and the load reduction from implementation of 5% voltage reductions are used in developing the ICR-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 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." The voltage reduction load relief values assumed as offsets against the Installed Capacity Requirement for the summer and winter seasons in each of the Capacity Commitment Periods are shown in Table 9. These assumptions use the benchmark 1.5% load relief value specified in Appendix A of Operating Procedure No. 4. This benchmark reduction value is derived from the values actually observed during voltage reduction tests.

**Table 9 – Load Relief Assumed Obtainable from Operating Procedure No. 4 Actions 6 and 8 - 5% Voltage Reduction (MW)**

| | Operating Procedure No. 4 Actions 6 & 8 5% Voltage Reduction |
|---|---|
| **Jun 2017 - Sep 2017** | 419 |
| **Oct 2017 - May 2018** | 312 |
| | |
| **Jun 2018 - Sep 2018** | 425 |
| **Oct 2018 - May 2019** | 316 |
| | |
| **Jun 2019 - Sep 2019** | 430 |
| **Oct 2019 - May 2020** | 319 |

The details of the tie benefit assumptions are described below.

## 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 WITH NEIGHBORING CONTROL AREAS ARE ACCOUNTED FOR IN DETERMINING THE ICR-RELATED VALUES.**

**A:** The New England resource planning reliability criterion requires that adequate capacity resources be planned and installed such that disconnection of firm load would not occur more often than once in ten years due to a capacity deficiency after taking into account the load and capacity relief obtainable from implementing Operating Procedure No. 4. In other words, load and capacity relief assumed obtainable from implementing Operating Procedure No. 4 actions are direct substitutes for capacity resources in meeting the once in ten 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 ICR-Related Values 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 that 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 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 is conducting its planning, maintenance scheduling, unit commitment or real-time operations with a goal of maintaining its emergency assistance at a level needed to maintain the reliability of the New England system.

**Q: PLEASE DESCRIBE WHAT TIE BENEFITS WERE USED FOR THE 2017-2018, 2018-2019 AND 2019-2020 CAPACITY COMMITMENT PERIODS.**

**A:** Under Section III.12.9 of the Tariff, the ISO is required to perform a tie reliability benefits study, which provides the total overall tie benefit value available from all interconnections with adjacent Control Areas and the contribution of tie benefits from each of these adjacent Control Areas, for the FCA and the third annual reconfiguration auction for each Capacity Commitment Period. For the first and second annual reconfiguration auctions for a Capacity Commitment Period, Section III.12.9 of the Tariff states that the tie benefits calculated for the associated FCA shall be utilized in determining the Installed Capacity Requirement, Local Sourcing Requirements and Maximum Capacity Limits, adjusted to account for any changes in import capability of interconnections with neighboring Control Areas and changes in Import Capacity Resources using the methodologies in Section III.12.9.6 of the Tariff.

Therefore, for ARA 3 for the 2017-2018 Capacity Commitment Period, a tie reliability benefits study was performed. For ARA 2 for the 2018-2019 Capacity Commitment Period and ARA 1 for the 2019-2020 Capacity Commitment Period, the associated FCA tie reliability benefits value was utilized in the ICR-Related Values calculations. No adjustments were necessary to these tie benefit values to account for changes in import capability of interconnections with neighboring Control Areas and changes in Import Capacity Resources.

**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 assumed import transfer capability of each of those interconnections that were used for calculating tie benefits for ARA 3 for the 2017-2018 Capacity Commitment Period:

**Table 10 – 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 |

In the first half of 2016, the ISO reviewed the transfer limits for each interconnection/interface based on the latest available information regarding forecasted topology and load forecast information. The ISO determined that no changes to the established external interface limits were warranted. Accordingly, in calculating tie benefits to be used in the calculations of the ICR-Related Values for ARA 3 for the 2017-2018 Capacity Commitment Period, the ISO used the transfer capability values from its most recent transfer capability analyses.

**Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES FOR THE 2017-2018, 2018-2019 AND 2019-2020 CAPACITY COMMITMENT PERIODS.**

**A.** The total, individual control area and individual interconnection tie reliability benefit assumptions used in the calculations of the ICR-Related Values for ARA 3 for the 2017-2018 Capacity Commitment Period, ARA 2 for the 2018-2019 Capacity Commitment Period, and ARA 1 for the 2019-2020 Capacity Commitment are shown in Table 10.

**Table 11 – Tie Reliability Benefit Assumptions (MW)**

| Control Area | 2017-2018 ARA 3 | 2018-2019 ARA 2 | 2019-2020 ARA 1 |
|---|---|---|---|
| Québec over the Phase II Interconnection | 1,108 | 953 | 975 |
| Québec over the Highgate Interconnection | 71 | 148 | 142 |
| Maritimes over the New Brunswick Ties | 224 | 523 | 519 |
| New York over AC Ties | 472 | 346 | 354 |
| Total | 1,875 | 1,970 | 1,990 |

Tie benefits are assumed not available over the Cross Sound Cable because the import capability of the Cross Sound Cable for tie benefits was determined to be zero.

**Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR ARA 3 FOR THE 2017-2018 CAPACITY COMMITMENT PERIOD THE SAME AS THE METHODOLOGY USED FOR THE CORRESPONDING FCA?**

**A:** The methodology for calculating tie benefits used in the calculations of ICR-Related Values for ARA 3 for the 2017-2018 Capacity Commitment Period is the same methodology used to calculate the tie benefits used in the calculation of the Installed

Capacity Requirement and related values for the 2017-2018 Capacity Commitment Period's FCA. This methodology is described in detail in Section III.12.9 of the Tariff.

## IV. LOCAL SOURCING REQUIREMENTS

**Q: WHAT ARE IMPORT-CONSTRAINED CAPACITY ZONES?**

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

**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, and 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) Transmission Security Analysis Requirement. The Local Sourcing Requirement is applied to import-constrained Capacity Zones within New England.

**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 Capacity Zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study until the reliability threshold, or target LOLE of 0.105,[15] is achieved.

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

**A:** The Transmission Security Analysis is a deterministic reliability assessment of an import-constrained area and is a basic security review set out in 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.[16] 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. In accordance with ISO Planning Procedure No. 3 and NPCC's Regional Reliability Reference Directory #1, this analysis also includes evaluations of both: (1) the loss of the most critical generator and the most critical

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

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

transmission element ("Line-Gen"), and; (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element ("Line-Line"). These deterministic analyses are currently used each day by the ISO's System Operations Department to assess the amount of capacity to be committed day-ahead. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine if a resource seeking to retire or de-list would violate reliability criteria.

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

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

The second difference relates to the application of assumed forced outages to fast-start (also referred to as "peaking") generating resources. For fast-start generating resources, an operational de-rating factor of 20% was applied in the Transmission Security Analysis instead of a forced outage assumption. This 20% de-rating factor is used because the traditional generating resource forced outage statistical measure used for the Installed Capacity Requirement calculations does not explicitly capture the peaking generating resources' ability to start and remain on-line when requested to do so after the occurrence of a contingency. Consequently, it has been the ISO's experience and practice to model the start-up performance of the peaking generation in Transmission Security Analyses with a 20% de-rating assumption.

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

**Q: PLEASE DESCRIBE THE LOCAL RESOURCE ADEQUACY REQUIREMENTS, TRANSMISSION SECURITY ANALYSIS REQUIREMENTS AND LOCAL SOURCING REQUIREMENTS FOR EACH OF THE ARAs.**

**A:** Tables 12-14 below show the Local Resource Adequacy Requirements, Transmission Security Analysis Requirements and resulting Local Sourcing Requirements for the relevant Capacity Zones for the 2017-2018, 2018-2019, and 2019-2020 Capacity Commitment Periods.

**Table 12 – Import-Constrained Capacity Zone Requirements for 2017-2018 ARA 3 (MW)**

| Capacity Zone | Transmission Security Analysis Requirement | Local Resource Adequacy Requirement | Local Sourcing Requirement |
|---|---|---|---|
| Connecticut | 7,029 | 6,909 | 7,029 |
| NEMA/Boston | 3,361 | 2,862 | 3,361 |

**Table 13 – Import-Constrained Capacity Zone Requirements for 2018-2019 ARA 2 (MW)**

| Capacity Zone | Transmission Security Analysis Requirement | Local Resource Adequacy Requirement | Local Sourcing Requirement |
|---|---|---|---|
| Connecticut | 7,072 | 7,078 | 7,078 |
| NEMA/Boston | 3,445 | 2,932 | 3,445 |
| SEMA/RI | 6,305 | 6,804 | 6,804 |

**Table 14 – Import-Constrained Capacity Zone Requirements for 2019-2020 ARA 1 (MW)**

| Capacity Zone | Transmission Security Analysis Requirement | Local Resource Adequacy Requirement | Local Sourcing Requirement |
|---|---|---|---|
| SENE | 9,637 | 9,360 | 9,637 |

## V. MAXIMUM CAPACITY LIMITS

**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: WHAT IS THE MAXIMUM CAPACITY LIMIT?**

**A:** The Maximum Capacity Limit is the maximum amount of resources that can be procured from an export-constrained Capacity Zone to meet the regional Installed Capacity Requirement. Generally speaking, this is the amount of capacity that can be used to fully meet the needs within the export-constrained Capacity Zone plus that amount which can reasonably be expected to be exported from the Capacity Zone to meet regional needs. The Maximum Capacity Limit is applied to export-constrained Capacity Zones within New England.

**Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE MAXIMUM CAPACITY LIMIT.**

**A:** In order to determine the Maximum Capacity Limit, the New England net Installed Capacity Requirement and the Local Resource Adequacy Requirement of the "*Rest of New England*" are needed. *Rest of New England* refers to all areas except the export-constrained Capacity Zone under study. Given that the net Installed Capacity Requirement is the total amount of resources that the region needs to meet the 0.1

days/year LOLE, and the Local Resource Adequacy Requirement for the *Rest of New England* is the minimum amount of resources required for that area to satisfy its reliability criterion, the difference between the two is the maximum amount of resources that can be used within the export-constrained Capacity Zone to meet the 0.1 days/year LOLE.

**Q: PLEASE DESCRIBE THE MAXIMUM CAPACITY LIMIT FOR THE MAINE CAPACITY ZONE FOR ARA 3 FOR THE 2017-2018 CAPACITY COMMITMENT PERIOD.**

**A:** For ARA 3 for the 2017-2018 Capacity Commitment Period, the Maximum Capacity Limit for the Maine Capacity Zone is 4,295 MW. This is the amount of capacity resources that ARA 3 for the 2017-2018 Capacity Commitment Period can procure from the Maine Capacity Zone, including Import Capacity Resources using the New Brunswick ties.

**Q: WHY WAS A MAXIMUM CAPACITY LIMIT NOT CALCULATED FOR ARA 2 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD OR ARA 1 FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD?**

**A:** No export-constrained zones were modeled for the 2018-2019 Capacity Commitment Period FCA or the 2019-2020 Capacity Commitment Period FCA. Accordingly, Maximum Capacity Limits were not calculated for the 2018-2019 Capacity Commitment Period FCA or the 2019-2020 Capacity Commitment Period FCA. Thus, Maximum Capacity Limits are not being calculated for ARA 2 for the 2018-2019 Capacity Commitment Period or ARA 1 for the 2019-2020 Capacity Commitment Period.

## 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").[17] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff, the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each FCA.

**Q: PLEASE DESCRIBE THE HQICC VALUES FOR EACH OF THE ANNUAL RECONFIGURATION AUCTIONS.**

**A:** For ARA 3 for the 2017-2018 Capacity Commitment Period, the HQICC value is 1,108 MW for each month of the period.

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[17] *See* Section I.2.2 of the Tariff (stating in the definition of "Hydro-Quebec Interconnection Capability Credit" that "[a]n appropriate share of the HQICC shall be assigned to an IRH if the Hydro Quebec (HQ) Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate."). *See also* Section III.12.9.7 of the Tariff ("The tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the Interconnection Rights Holders or their designees in proportion to their respective percentage shares of the HQ Phase I and the HQ Phase II facilities, in accordance with Section I of the Transmission, Markets and Services Tariff.").

For ARA 2 for the 2018-2019 Capacity Commitment Period, the same 953 MW HQICC value utilized for the 2018-2019 Capacity Commitment Period FCA is used for each month of the period.

For ARA 1 for the 2019-2020 Capacity Commitment Period, the same 975 MW HQICC value utilized for the 2019-2020 Capacity Commitment Period FCA is used for each month of the period.

## VII. DEMAND CURVE VALUES

**Q: WHY WERE DEMAND CURVE VALUES CALCULATED FOR ARA 2 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD AND ARA 1 FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD?**

**A:** Starting with the 2018-2019 Capacity Commitment Period, a System-Wide Capacity Demand Curve was used in the FCA to procure needed capacity. Like the Installed Capacity Requirements, Local Sourcing Requirements, Maximum Capacity Limits, and HQICCs, the Demand Curve Values need to be recalculated for the ARAs to reflect updated system conditions. Accordingly, the ISO calculated the Demand Curve Values for ARA 2 for the 2018-2019 Capacity Commitment Period and ARA 1 for the 2019-2020 Capacity Commitment Period.

**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 ARA 2 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD?**

**A:** The 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the Demand Curve are 32,395 MW and 36,159 MW, respectively.

**Q: WHAT ARE THE CAPACITY REQUIRMENT VALUES CALCULATED BY THE ISO FOR THE DEMAND CURVE FOR THE PURPOSES OF CONDUCTING ARA 1 FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD?**

**A:** The 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the Demand Curve are 32,714 MW and 36,526 MW, respectively.

**Q: DOES THIS CONCLUDE YOUR TESTIMONY?**

**A:** Yes.

I declare that the foregoing is true and correct.

Executed on 11/28/16

Carissa Sedlacek 11/28/16

Carissa Sedlacek

Executed on 11/28/16

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Maria Scibelli

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