December 1, 2017

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. ER18-___-000, Filing of Installed Capacity Requirements, Hydro-Quebec Interconnection Capability Credits and Related Values for 2018-2019, 2019-2020 and 2020-2021 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"), capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve Values"), and Marginal Reliability

[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 3 for the 2018-2019 Capacity Commitment Period or ARA 2 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.

Impact ("MRI") Capacity Demand Curves[5] (collectively, the "ICR-Related Values") for (1) the third annual reconfiguration auction for the 2018-2019 Capacity Commitment Period ("ARA 3 for the 2018-2019 Capacity Commitment Period"), (2) the second annual reconfiguration auction for the 2019-2020 Capacity Commitment Period ("ARA 2 for the 2019-2020 Capacity Commitment Period), and (3) the first annual reconfiguration auction for the 2020-2021 Capacity Commitment Period ("ARA 1 for the 2020-2021 Capacity Commitment Period").[6] Collectively, ARA 3 for the 2018-2019 Capacity Commitment Period, ARA 2 for the 2019-2020 Capacity Commitment Period, and ARA 1 for the 2020-2021 Capacity Commitment Period are referred to herein as the "ARAs." The testimony of Ms. Carissa Sedlacek (the "Sedlacek 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 2018-2019 Capacity Commitment Period is to be held starting on March 1, 2018, ARA 2 for the 2019-2020 Capacity Commitment Period is to be held starting on August 1, 2018, and ARA 1 for the 2020-2021 Capacity Commitment Period is to be held starting on June 1, 2018. 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, 2018, 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

[5] Capacity requirement values for the System-Wide Capacity Demand Curve are calculated starting with the FCA for the 2018-2019 Capacity Commitment Period. Accordingly, the ISO calculated Demand Curve Values for ARA 3 for the 2018-2019 Capacity Commitment Period and ARA 2 for the 2019-2020 Capacity Commitment Period. MRI Capacity Demand Curves are calculated starting with the FCA for the 2020-2021 Capacity Commitment Period. Accordingly, the ISO calculated MRI Capacity Demand Curves for ARA 1 for the 2020-2021 Capacity Commitment Period.

[6] The 2018-2019 Capacity Commitment Period runs from June 1, 2018 to May 31, 2019, the 2019-2020 Capacity Commitment Period runs from June 1, 2019 to May 31, 2020, and the 2020-2021 Capacity Commitment Period runs from June 1, 2020 to May 31, 2021.

[7] 18 C.F.R. § 35.3(a)(1) (2014).

short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and has grown to include more than 480 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]

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[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 2018-2019 Capacity Commitment Period, ARA 2 for the 2019-2020 Capacity Commitment Period, and ARA 1 for the 2020-2021 Capacity Commitment Period. The ISO anticipates conducting these ARAs in March, August and June of 2018, 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 due to changes in system conditions that have occurred since the calculation of the Installed Capacity Requirement and related values for the associated Capacity Commitment Period's FCA; and (2) to adjust resources' Qualified Capacity so that a qualified resource can acquire or shed a Capacity Supply Obligation for a Capacity Commitment Period.

With the exception of the methodology used to reflect the behind-the-meter ("BTM") photovoltaic ("PV") forecast, the ICR-Related Values filed herewith have been calculated using the same methodologies that were used in calculating the Installed Capacity Requirements and related values for the annual reconfiguration auctions conducted in 2017. 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 change in the methodology used to reflect the contributions of the BTM 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 criteria 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 2018-2019 Capacity Commitment Period, the Filing Parties propose an Installed Capacity Requirement value of 34,277 MW. The 34,277 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 1,030 MW per month.[18] Thus, the net Installed Capacity Requirement for ARA 3 for the 2018-2019 Capacity Commitment Period is 33,247 MW.[19]

For ARA 2 for the 2019-2020 Capacity Commitment Period, the Filing Parties propose an Installed Capacity Requirement value of 34,382 MW. The 34,382 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 975 MW per

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[17] *See* 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); Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2020-2021 Capacity Commitment Period, Docket No. ER17-320-000 (filed Nov. 8, 2016).

[18] The HQICC is a monthly value.

[19] Sedlacek Testimony at 11.

month. Thus, the net Installed Capacity Requirement for ARA 2 for the 2019-2020 Capacity Commitment Period is 33,407 MW.[20]

For ARA1 for the 2020-2021 Capacity Commitment Period, the Filing Parties propose an Installed Capacity Requirement value of 34,619 MW. The 34,619 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to the HQICC value of 959 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 2020-2021 Capacity Commitment Period is 33,660 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 electrically located in a Capacity Zone 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 2018-2019 Capacity Commitment Period, the proposed Local Sourcing Requirement for the Connecticut Capacity Zone is 7,020 MW, the proposed Local Sourcing Requirement for the Northeast Massachusetts ("NEMA")/Boston Capacity Zones is 3,391 MW, and the Local Sourcing Requirement for the Southeast Massachusetts ("SEMA")/Rhode Island ("SEMA/RI") Capacity Zone is 6,940 MW. No export-constrained

[20] Sedlacek Testimony at 11.

[21] *Id.* at 11-12.

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 3 for the 2018-2019 Capacity Commitment Period.

For ARA 2 for the 2019-2020 Capacity Commitment Period, the proposed Local Sourcing Requirement for the Southeast New England ("SENE")[22] Capacity Zone is 9,743 MW. 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 2 for the 2019-2020 Capacity Commitment Period.

For ARA 1 for the 2020-2021 Capacity Commitment Period, the proposed Local Sourcing Requirement for the SENE Capacity Zone is 9,854 MW. The proposed Maximum Capacity Limit for the Northern New England ("NNE") [23] export-constrained Capacity Zone is 8,890 MW.

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 2018-2019 Capacity Commitment Period, the ISO used 1,030 MW of HQICCs for each month in determining the Installed Capacity Requirement for the 2018-2019 Capacity Commitment Period. The HQICC values used for the calculation of the Installed Capacity Requirement for ARA 2 for the 2019-2020 Capacity Commitment Period, and ARA 1 for the 2020-2021 Capacity Commitment Period are the same values (975 MW and 959 MW, respectively) used in the FCAs for those Capacity Commitment Periods, which were approved by the Commission.[24]

VII. DEMAND CURVE VALUES AND MRI CAPACITY DEMAND CURVES

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 3 for the 2018-2019 Capacity Commitment Period and ARA 2 for the 2019-2020 Capacity Commitment Period. Specifically, Section III.12.1 of the Tariff states that "[t]he ISO shall

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

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

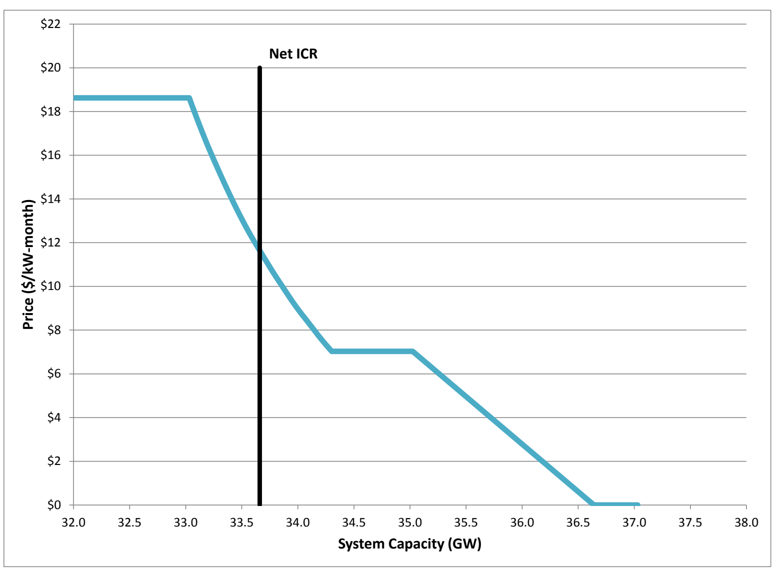
[24] *ISO New England Inc*., 154 FERC ¶ 61,008 (2016); *ISO New England Inc.*, Docket No. ER17-320-000 (December 6, 2016) (delegated letter order).

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 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 3 for the 2018-2019 Capacity Commitment Period are 32,226 MW and 35,840 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 2 for the 2019-2020 Capacity Commitment Period are 32,379 MW and 36,079 MW, respectively.

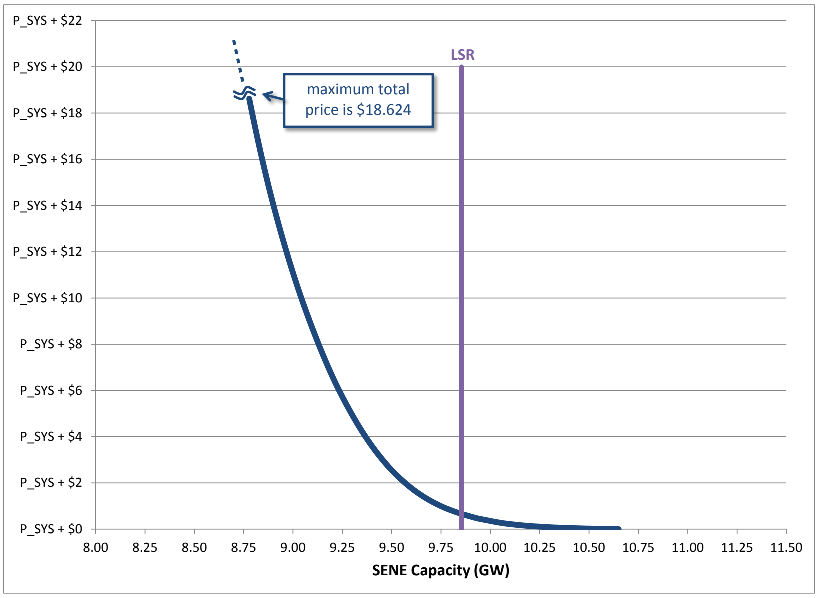
In the FCA for the 2020-2021 Capacity Commitment Period, MRI Demand Curves were used to procure needed capacity. Therefore, the ISO calculates MRI Demand Curves for all ARAs for the 2020-2021 Capacity Commitment Period using the same methodology as that is used for calculating the Installed Capacity Requirement.[25] The MRI Capacity Demand Curves for ARA 1 for the 2020-2021 Capacity Commitment Period are as follows:

System-Wide Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period

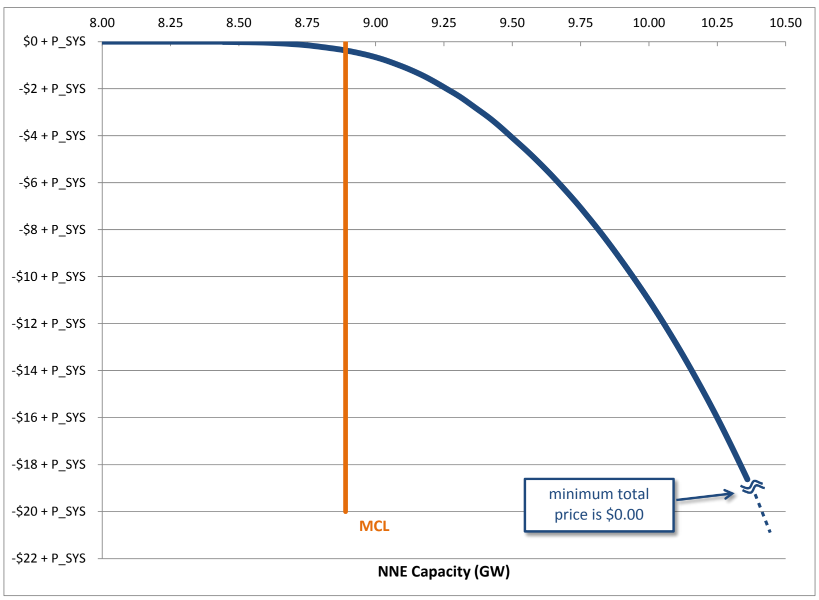


[25] The development of the MRI Capacity Demand Curves is explained in the Sedlacek Testimony at 45-50.

SENE Import-Constrained Capacity Zone Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period



NNE Export-Constrained Capacity Zone Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period



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 change in the methodology used to reflect the 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 ARAs conducted in 2017. 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 2018-2019, 2019-2020 and 2020-2021 Capacity Commitment Periods are major inputs into the calculation of the ICR-Related Values, [26] and the forecasted peak loads for the individual Capacity Zones are used to develop the associated Local Sourcing Requirements and Maximum Capacity Limits, and MRI Capacity Demand Curves.[27] For the purpose of calculating the ICR-Related Values, the ISO used the forecast published in the 2017-2026 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2017 ("2017 CELT Report").[28] The 2017 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. This methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee.[29]

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

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[26] The forecasted peak loads for the New England Control Area are shown in the Sedlacek Testimony at 14.

[27] The forecasted peak loads for each of the relevant Capacity Zones are shown in the Sedlacek Testimony at 14.

[28] *Id.* at 13.

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

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.

New for the ARAs to be Conducted in 2018: Hourly Profile Methodology Used to Reflect the BTM PV Forecast

This year, there is a modification in the methodology used to reflect the BTM PV forecast in the calculation of the ICR-Related Values. As explained in the filing of the Installed Capacity Requirement and related values for the twelfth FCA ("FCA 12"), in 2014, the rapid growth and installation of PV resources led the ISO, working with the Distributed Generation Forecast Working Group ("DGFWG"), to develop a forecast that captures the effects of recently installed BTM PV resources and BTM PV resources expected to be installed within the forecast horizon in order to forecast the potential future peak loads as accurately as possible. The ISO completed the region's first PV forecast in April of 2014 and incorporated it in long-term, ten-year transmission planning. However, in 2014, the ISO did not reflect the PV forecast in the calculations of the Installed Capacity Requirement and related values for the ninth FCA ("FCA 9"). For that reason, NEPOOL did not support the Installed Capacity Requirement and related values for FCA 9.[30]

In its order on the Installed Capacity Requirement and related values for FCA 9, while the Commission accepted the values, it directed the ISO to fully explore the incorporation of distributed generation into the Installed Capacity Requirement calculations in the stakeholder process. The Commission stated that it expected the ISO to do this on a schedule that would allow these factors to be reflected, if determined appropriate, in the Installed Capacity Requirement calculations for the tenth FCA ("FCA 10").[31] Accordingly, to comply with FERC's directive, starting with FCA 10, the ISO has reflected the forecasted amount of BTM PV in the Installed Capacity Requirement calculations for the FCAs and the ARAs as a reduction to the load forecast.[32]

For FCA 10 and the eleventh FCA, and the ARAs conducted in 2016 and 2017, the ISO used a "Reliability Hours" methodology to account for forecasted BTM PV in the calculation of the Installed Capacity Requirements and related values. Specifically, this methodology estimated BTM PV contributions to reduce load in the summer peak hours (*i.e*. the hours ending

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[30] Sedlacek Testimony at 15.

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

[32] Sedlacek Testimony at 16.

14:00 – 18:00 in May through September). Contributions in all other hours and months were assumed to be zero. Some Market Participants pointed out that this methodology could underestimate BTM PV contributions, because it did not consider contributions outside the Reliability Hours. For that reason, the Reliability Hours methodology was considered a temporary approach until a methodology that more accurately reflects the real contribution of BTM PV to load reduction could be developed.[33]

For FCA 12 and the ARAs to be conducted in 2018, the ISO was able to develop an "hourly profile" methodology to account for BTM PV in all hours of the day and all months of the year in the calculations of the ICR-Related Values. To develop the hourly profile methodology, the ISO used the latest data from the National Renewable Energy Laboratory's National Solar Radiation Database. This is comprehensive weather data that includes the main weather drivers of PV and corresponds to both the geographic area and period of interest. With these data and state-of-the-art PV modeling tools, the ISO conducted simulations of PV systems' performance for many thousands of individual systems located throughout the region, with sizes ranging from "rooftop" (<10 kW) to "utility scale" (MW-scale). The results of the simulations were then benchmarked to available measured data for a summer period. Because simulated data was consistently higher than measured data, the ISO applied a downward adjustment to all simulation results to make them consistent with measured data. The ISO further validated simulation results by comparing final simulated regional PV profiles to two sources of measured data on a variety of historical summer peak load days from 2012-2014. This validation showed that final simulated PV profiles closely match measured data during summer peak conditions.[34]

The hourly profile methodology is better than the Reliability Hours methodology because it reflects BTM PV's contributions in reducing load in all hours of the day and all months of the year and the historical weather year used for the Installed Capacity Requirement, as opposed to reflecting BTM PV contributions only during the Reliability Hours.

B. Resource Capacity Ratings

The ICR-Related Values submitted in this filing are based on the latest available Existing Capacity Resource dataset for the 2018-2019, 2019-2020, and 2020-2021 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

[33] Sedlacek Testimony at 17.

[34] *Id.* at 17-18.

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 that 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 ARAs.[35]

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.[36] 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.[37]

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.[38]

In the Installed Capacity Requirement calculations, performance for the Real-Time Demand Response Resource category 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 2012 through 2016. Demand Resources in the On-Peak Demand and Seasonal Peak Demand

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[35] The Sedlacek Testimony provides the total MWs for each type of capacity resource assumed in the ICR-Related Values calculations for the 2018-2019, 2019-2020, and 2020-2021 Capacity Commitment Periods. *See* Sedlacek Testimony at 22-23.

[36] *Id*. at 25.

[37] *Id.*

[38] *Id* at 26.

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.[39]

D. Other Assumptions

In the development of the Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit and Demand Curves Values, assumed emergency 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.[40]

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 2017, 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.[41] The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the Installed Capacity Requirement for ARA 3 for the 2018-2019 Capacity Commitment Period, for both internal and external transmission interfaces, the ISO used the transfer capability values

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[39] Sedlacek Testimony at 26.

[40] *Id.* at 28-29.

[41] 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 Testimony at 32.

from its most recent transfer capability analyses.[42] Pursuant to Section III.12.9.2 of the Tariff, tie benefits for ARA 3 for the 2018-2019 Capacity Commitment Period were calculated using “at criterion” modeling assumptions. Using this methodology, a total of 1,908 MW of tie benefits was utilized in the calculation of the Installed Capacity Requirement for ARA 3 for the 2018-2019 Capacity Commitment Period based on the results of the tie benefits study. A breakdown of this total value is as follows: 1,030 MW from Quebec over the Phase II interconnection, 107 MW from Quebec over the Highgate interconnection, 425 MW from New Brunswick (Maritimes) over the New Brunswick ties and 346 MW from New York over the AC ties.[43]

Pursuant to Section III.12.9.1.1 of the Tariff, the Installed Capacity Requirement calculation for ARA 2 for the 2019-2020 Capacity Commitment Period assumes the same level of tie benefits calculated for the corresponding FCA of 1,990 MW total tie benefits.[44] 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.

Pursuant to Section III.12.9.1.1 of the Tariff, the Installed Capacity Requirement calculation for ARA 1 for the 2020-2021 Capacity Commitment Period also assumes the same level of tie benefits calculated for the corresponding FCA of 1,950 MW total tie benefits. A breakdown of this total value is as follows: 959 MW from Quebec over the Phase II interconnection, 145 MW from Quebec over the Highgate interconnection, 500 MW from New Brunswick (Maritimes) over the New Brunswick ties and 346 MW from New York over the AC ties.

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

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[42] Sedlacek Testimony at 33.

[43] *Id.*, Table 10.

[44] 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 Testimony at 32, there have been no adjustments made to the tie benefits values calculated for ARA 2 for the 2019-2020 Capacity Commitment Period or ARA 1 for the 2020-2021 Capacity Commitment Period 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.

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 electrically located 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.

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.[45]

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 criteria. 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.[46]

The Transmission Security Analysis Requirement 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 Testimony.[47]

The following tables[48] contain the Local Resource Adequacy Requirement and

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[45] Section III.12.2.1 of the Tariff.

[46] Section III.12.2.1.2(a) of the Tariff. *See also* Sedlacek Testimony at 35-36.

[47] Sedlacek Testimony at 36-37.

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

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.

ARA 3 for the 2018-2019 Capacity Commitment Period

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
Connecticut	6,901	7,020	7,020
NEMA/Boston	3,391	2,898	3,391
SEMA-RI	6,439	6,940	6,940

ARA 2 for the 2019-2020 Capacity Commitment Period

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	9,743	9,473	9,743

ARA 1 for the 2020-2021 Capacity Commitment Period

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	9,854	9,560	9,854

In addition to the values presented in the tables, the ISO calculated the Maximum Capacity Limit for the NNE export-constrained Capacity Zone for ARA 1 for the 2020-2021 Capacity Commitment Period. As already mentioned in Section V of this filing letter, the proposed Maximum Capacity Limit is 8,890 MW.

X. STAKEHOLDER PROCESS

At its October 17, 2017 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 one abstention. 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, Demand Curve Values, and MRI Capacity Demand Curves passed by a show of hands with four oppositions and seven abstentions. At its November 3, 2017 meeting, the Participants Committee voted to support the proposed HQICCS (with oppositions and abstentions noted). The Participants Committee also voted to support the proposed Installed Capacity Requirements, Local Sourcing Requirements, Maximum Capacity Limits, Demand Curve Values, and MRI Capacity Demand Curves with a 62.22% vote in favor.

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, 2018.[49]

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.[50] 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, sponsored solely by the ISO;
- List of governors and utility regulatory agencies in Connecticut, Maine,

[49] 18 C.F.R. § 35.3.

[50] 18 C.F.R. § 35.13.

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, 2018.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/committees/nepool_part/index.html. An electronic copy of this transmittal letter and the accompanying materials 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, 2018.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Attachments

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	**Docket No. ER18-___-000**
New England Power Pool	**)**	

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

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

A: 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.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

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.

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"), capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve Values"), and Marginal Reliability Impact ("MRI") Capacity Demand Curves[2] (collectively, the "ICR-Related Values") for: (1) the third annual reconfiguration auction for the 2018-2019 Capacity Commitment Period ("ARA 3 for the 2018-2019 Capacity Commitment Period"); (2) the second annual reconfiguration auction for the 2019-2020 Capacity Commitment Period ("ARA 2 for the 2019-2020 Capacity Commitment Period"); and (3) the first annual reconfiguration auction for the 2020-2021 Capacity Commitment Period ("ARA 1 for the 2020-2021 Capacity Commitment Period").[3] Collectively, ARA 3 for the 2018-2019 Capacity Commitment Period, ARA 2 for the 2019-2020 Capacity Commitment Period, and ARA 1 for the 2020-2021 Capacity Commitment Period are referred to herein as the "ARAs."

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[1] Maximum Capacity Limits were not calculated for ARA 3 for the 2018-2019 Capacity Commitment Period or ARA 2 for the 2019-2020 Capacity Commitment Period because no export-constrained zones were modeled in and, accordingly, 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.

[2] Capacity requirement values for the System-Wide Capacity Demand Curve are calculated starting with the FCA for the 2018-2019 Capacity Commitment Period. Accordingly, the ISO calculated Demand Curve Values for ARA 3 for the 2018-2019 Capacity Commitment Period and ARA 2 for the 2019-2020 Capacity Commitment Period. MRI Capacity Demand Curves are calculated starting with the FCA for the 2020-2021 Capacity Commitment Period. Accordingly, the ISO calculated MRI Capacity Demand Curves for ARA 1 for the 2020-2021 Capacity Commitment Period.

[3] The 2018-2019 Capacity Commitment Period runs from June 1, 2018 to May 31, 2019, the 2019-2020 Capacity Commitment Period runs from June 1, 2019 to May 31, 2020, and the 2020-2021 Capacity Commitment Period runs from June 1, 2020 to May 31, 2021.

My 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 due to changes in system conditions that have occurred since the calculation of the Installed Capacity Requirement and related values for the associated Capacity Commitment Period's FCA; and (2) to adjust resources' Qualified Capacity so that a qualified resource can acquire or shed a Capacity Supply 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?

A: Generally, yes. With the exception of the methodology used to reflect the behind-the-meter ("BTM") photovoltaic ("PV") forecast (which is explained in Section III.1 of this testimony), the methodology used for the calculations of the ICR-Related Values is the same methodology that was used in 2016 for calculating the Installed Capacity Requirements and related values for the third annual reconfiguration auction for the 2017-2018 Capacity Commitment Period, the second annual reconfiguration auction for the 2018-2019 Capacity Commitment Period, the first annual reconfiguration auction for the 2019-2020 Capacity Commitment Period, and the 2020-2021 Capacity Commitment Period's FCA.

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 2018-2019 Capacity Commitment Period: Local Sourcing Requirements for the Connecticut, Northeast Massachusetts ("NEMA")/Boston, and the combined Southeast Massachusetts ("SEMA") and Rhode Island ("RI") ("SEMA-RI") Capacity Zones
- For ARA 2 for the 2019-2020 Capacity Commitment Period: Local Sourcing Requirement for the Southeast New England ("SENE") Capacity Zone[4]
- For ARA 1 for the 2020-2021 Capacity Commitment Period: Local Sourcing Requirement for the SENE Capacity Zone, and Maximum Capacity Limit for the Northern New England ("NNE") Capacity Zone[5]

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

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

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

A: The ISO calculated Demand Curve Values for ARA 3 for the 2018-2019 Capacity Commitment Period and ARA 2 for the 2019-2020 Capacity Commitment Period because system-wide demand curves were used in the FCAs for those Capacity Commitment Periods.

Q: FOR WHICH ANNUAL RECONFIGURATION AUCTION DID THE ISO DEVELOP MRI CAPACITY DEMAND CURVES?

A: The ISO developed MRI Capacity Demand Curves for ARA 1 for the 2020-2021 Capacity Commitment Period for the system, SENE and NNE Capacity Zones because MRI Demand Curves were developed for the FCA for that Capacity Commitment Period.

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 criterion defined for the New England Control Area. These requirements are documented in Section III.12 of the Tariff, which states, in relevant part, that "[t]he ISO shall determine the Installed Capacity Requirement such that the probability of disconnecting non-interruptible customers due to resource deficiency, on average, will be no more than once in ten years. Compliance with this resource adequacy planning criterion shall be evaluated probabilistically, such that the loss of load expectation ("LOLE") of disconnecting non-interruptible customers due to resource deficiencies shall be no more than 0.1 day each year. The forecast Installed Capacity Requirement shall meet this resource adequacy planning criterion for each Capacity Commitment Period." Section III.12 of the Tariff also details the calculation methodology and the guidelines for the development of assumptions used in the calculation of the Installed Capacity Requirement.

The development of the Installed Capacity Requirement is consistent with the NPCC Full Member Resource Adequacy Criterion (Resource Adequacy Requirement R4), under which the ISO must probabilistically evaluate resource adequacy to demonstrate that the LOLE of disconnecting firm load due to resource deficiencies is, on average, no more than 0.1 days per year, while making allowances for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

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 New England Power Pool

("NEPOOL") Load Forecast Committee ("LFC"), [6] the Power Supply Planning Committee ("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 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

[6] 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.

calculation of the ICR-Related Values for the ARAs over the course of six meetings in May, June, July, August, September, and October 2017.

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

A: As it is 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 and load forecast uncertainty. 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 resources 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 resource addition. 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 2018-2019 Capacity Commitment Period is 34,277 MW. The 34,277 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 1,030 MW per month.[7] Thus, the net Installed Capacity Requirement for use in ARA 3 for the 2018-2019 Capacity Commitment Period will be 33,247 MW.

The proposed Installed Capacity Requirement for ARA 2 for the 2019-2020 Capacity Commitment Period is 34,382 MW. The 34,382 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 975 MW per month. Thus, the net Installed Capacity Requirement for use in ARA 2 for the 2019-2020 Capacity Commitment Period is 33,407 MW.

The proposed Installed Capacity Requirement for ARA1 for the 2020-2021 Capacity Commitment Period is 34,619 MW. The 34,619 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to the HQICC value of 959 MW per month that are allocated to the Interconnection Rights Holders. Thus,

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[7] The HQICC is a monthly value.

after deducting the HQICC value, the net Installed Capacity Requirement for ARA 1 for the 2020-2021 Capacity Commitment Period is 33,660 MW. [8]

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.

[8] 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/2017/10/a6_ara_icr_tie_benefits_1018_2019_2020.zip This presentation also provides details on changes to the assumptions used in the calculation of the ICR-Related Values versus the Installed Capacity Requirements and related values calculated for the FCAs.

1. LOAD FORECAST

Q: PLEASE EXPLAIN HOW THE ISO DERIVED THE LOAD FORECAST ASSUMPTION 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 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.

For deterministic analyses such as the Transmission Security Analysis, the ISO used the reference 90/10 peak load forecast, which is net of BTM PV resources as published in the 2017 – 2026 Forecast Report of Capacity, Energy, Loads, and Transmission ("2017 CELT Report").

Q: PLEASE DESCRIBE THE PROJECTED NEW ENGLAND CONTROL AREA 50/50 PEAK LOADS FOR THE 2018-2019, 2019-2020 AND 2020-2021 CAPACITY COMMITMENT PERIODS.

A: The following table shows the 50/50 peak load forecast (MW), net of BTM PV, for the 2018-2019, 2019-2020, and 2020-2021 Capacity Commitment Periods as documented in the 2017 CELT Report.

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

Capacity Commitment Period	50/50
2018-2019	28,764
2019-2020	28,970
2020-2021	29,191

Q: PLEASE DESCRIBE THE PROJECTED 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE RELEVANT CAPACITY ZONES FOR THE 2018-2019, 2019-2020 AND 2020-2021 CAPACITY COMMITMENT PERIODS.

A: The projected 50/50 and 90/10 peak load forecast, net of BTM PV, from the 2017 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)

	Connecticut		NEMA/Boston		SEMA-RI		SENE		NNE	
Capacity Commitment Period	50/50	90/10	50/50	90/10	50/50	90/10	50/50	90/10	50/50	90/10
2018-2019	7,320	7,993	6,174	6,651	5,778	6,332	-	-	-	-
2019-2020	-	-	-	-	-	-	12,076	13,125	-	-
2020-2021	-	-	-	-	-	-	12,202	13,269	5,668	6,069

Q: PLEASE DESCRIBE THE DEVELOPMENT OF THE BTM PV FORECAST AT A HIGH LEVEL.

A: In 2014, the rapid growth of BTM PV resources led the ISO to develop a forecast that captures the effects of recently installed BTM PV resources and BTM PV resources expected to be installed within the forecast horizon in order to forecast the potential future peak loads as accurately as possible. Hence, each year since 2014, 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 BTM PV growth in New England), develops forecasts of future nameplate ratings of BTM PV installations anticipated over the 10-year planning horizon. These forecasts are created for each state based on policy drivers, recent BTM PV growth trends, and discount adjustments designed to represent a degree of uncertainty in future BTM PV commercialization.

Q: WHY IS THE BTM PV FORECAST ACCOUNTED FOR IN THE CALCULATIONS OF THE ICR-RELATED VALUES?

Growth of BTM PV reduces the amount of load that needs to be served during daylight hours, which include summer peak load hours. As mentioned above, in 2014, the ISO developed its first ever long-term PV forecast. However, that year, the ISO did not did not reflect the BTM PV forecast in the calculations of the Installed Capacity Requirement and related values for the ninth FCA ("FCA 9"). For that reason, NEPOOL did not support the Installed Capacity Requirement and related values for FCA 9. While FERC accepted the ISO's proposed Installed Capacity Requirement and related values, it directed the ISO to fully explore the incorporation of distributed generation into the Installed Capacity Requirement calculations for the tenth FCA ("FCA 10").[9] Accordingly, the BTM PV forecast has been reflected in the calculations of the Installed Capacity Requirement and related values starting with FCA 10.

Q: HOW DID THE ISO REFLECT THE CONTRIBUTIONS OF BTM PV TO LOAD REDUCTION IN FCA 10, THE ELEVENTH FCA ("FCA 11"), AND THE ARAs CONDUCTED IN 2015 AND 2016?

A: In FCA 10, FCA 11, and the ARAs conducted in 2015 and 2016, the ISO used a "Reliability Hours" methodology to reflect BTM PV as a reduction to load in the load forecast assumption used in the calculations of the Installed Capacity Requirement and related values. The Reliability Hours methodology estimated BTM PV contributions to reduce load in the summer peak hours (*i.e.* the hours ending 14:00 – 18:00 in the months of May through September). The contributions in all other hours/months were assumed to be zero. In order to determine the magnitude of load reduction impact of the BTM PV facilities to model during the Reliability Hours, the ISO used coincident hourly load and PV production data for the years 2012-2015 to estimate the amount of daily peak load reductions that can be expected during elevated summer load days. For this methodology, the estimated daily peak reduction value was kept constant for all Reliability Hours during the summer months, but was adjusted to reflect the incremental growth in the BTM PV forecast.

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

Q: DID THE ISO USE THE RELIABILITY HOURS METHODOLOGY TO ACCOUNT FOR BTM PV AS A REDUCTION IN THE LOAD FORECAST FOR FCA 12 AND THE ARAs TO BE CONDUCTED IN 2018?

A: No. The Reliability Hours methodology was a temporary approach until a methodology that more accurately reflects the real contribution of BTM PV to load reduction could be developed.

Q: WHAT METHODOLOGY DID THE ISO USE TO REFLECT THE CONTRIBUTIONS OF BTM PV TO REDUCE THE LOAD FORECAST FOR FCA 12 AND THE ARAs TO BE CONDUCTED IN 2018?

A: For FCA 12 and the ARAs to be conducted in 2018, the ISO developed an "hourly profile" methodology to determine the amount of load reduction provided by BTM PV in all hours of the day and all months of the year. The BTM PV hourly profile models the forecast of PV output as the full hourly load reduction value of BTM PV in all 8760 hours of the year. This reflects the actual impact of BTM PV installations in reducing system load.

Q: PLEASE EXPLAIN, AT A HIGH LEVEL, HOW THE ISO DEVELOPED THE HOURLY PROFILE METHODOLOGY TO ACCOUNT FOR THE BTM PV FORECAST IN THE CALCULATIONS OF THE ICR-RELATED VALUES.

A: Using the latest data from the National Renewable Energy Laboratory's National Solar Radiation Database and state-of-the-art PV modeling tools, the ISO conducted simulations of PV systems' performance for many thousands of individual systems located throughout New England with sizes ranging from "rooftop" (<10 kW) to "utility scale" (MW-scale). These simulations were designed to reflect a realistic fleet of BTM PV systems – for example, they were tailored to reflect the distribution of system sizes existing in each New England state at the end of 2016. The ISO benchmarked the simulation results to available measured data for a summer period, and applied a downward adjustment to all simulation profiles to make them consistent with the measured data. As final validation, the ISO compared the finalized regional PV profiles to two sources of measured data on a variety of historical summer peak load days from 2012 to 2014. The validation showed that final PV profiles closely match measured data during summer peak load conditions.[10]

Notably, to develop the hourly profile methodology, the ISO used detailed weather information for 2002, which is the historical year load profile that the ISO uses for the calculations of the Installed Capacity Requirement and related values, and NPCC uses for resource adequacy studies. Hence, because the weather strongly influences both BTM PV output and load, an important feature of the new methodology is that, by using weather data from the same historical year, the influence of the weather is captured both in the load forecast assumption and the BTM PV load reduction in the calculations of the ICR-Related Values for FCA 12 and the ARAs to be conducted in 2018.

[10] The ISO's most detailed presentation to the PSPC on the development of the BTM PV hourly profile methodology is available at: https://www.iso-ne.com/static-assets/documents/2017/06/pspc_6_22_2017_2002_PV_profile.pdf

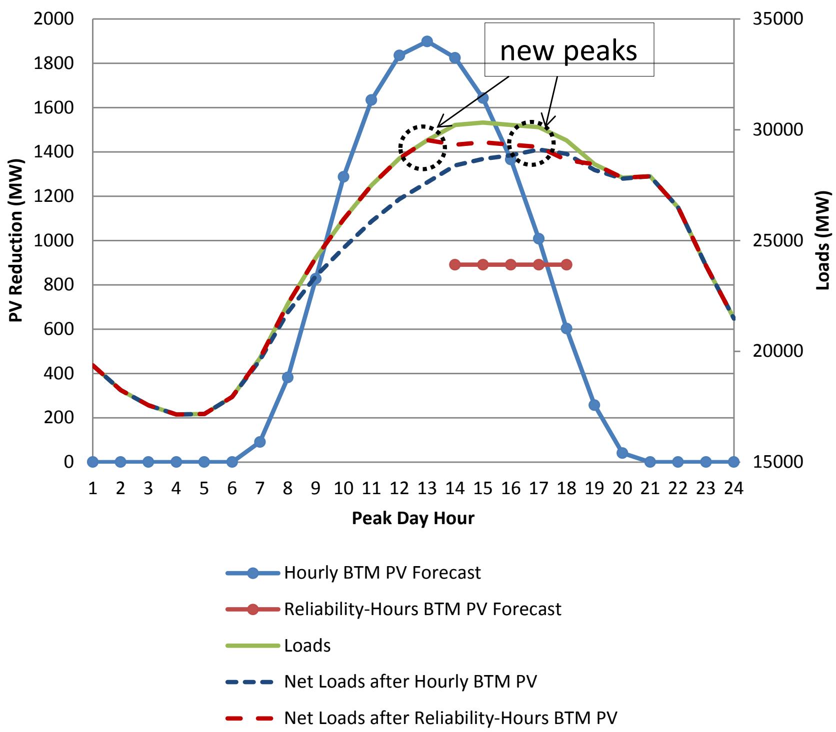
Q: WHY IS THE HOURLY PROFILE METHODOLOGY FOR MODELING THE BTM PV FORECAST IN THE ICR-RELATED VALUES CALCULATIONS AN IMPROVEMENT OVER THE RELIABILITY HOURS METHODOLOGY?

As previously mentioned, the ISO considered the Reliability Hours methodology a temporary approach until a method for realistically modeling the hourly BTM PV performance was developed. During the discussions of the assumptions for calculating the Installed Capacity Requirement and related values for FCA 11, some Market Participants questioned the continued validity of using the Reliability Hours methodology for modeling BTM PV and asked the ISO to develop the BTM PV hourly profiles needed to model PV output in all hours of the year.

The ISO believes that, beginning with the ICR-Related Values calculation for FCA 12 and the ARAs to be conducted in 2018, if the Reliability Hours methodology to model BTM PV is used, the load reduction value of increased penetrations of BTM PV would not be accurately reflected. The 2017 PV forecast[11] shows that the penetration of BTM PV has grown to the point at which, if the Reliability Hours methodology continues to be used, the hour of new peak net of BTM PV in the GE MARS model shifts from hour ending 15:00 (*i.e.* 3:00 p.m.) to hour ending 13:00 (*i.e.*, 1:00 p.m.), because no BTM PV is modeled in hour ending 13:00, which is the time of some of the highest BTM PV output. As a result, the true effect of BTM PV in reducing system load would not be captured.

[11] Details of the 2017 PV forecast are available at: https://www.iso-ne.com/static-assets/documents/2017/05/2017_solar_forecast_details_final.pdf

The Figure below shows this peak-shifting phenomenon graphically for the peak day with BTM PV output graphed on the first Y-axis and system load graphed on the second Y-axis. Using the Reliability Hours Methodology, the net load peak (red dashed line) is shifted to hour ending 13:00 which is outside the Reliability Hours window where BTM PV is not modeled. This is not an accurate representation of system conditions. Also shown is the hourly profile methodology with a net load peak (blue dashed line) occurring in hour ending 17:00. This is expected because, with increased BTM PV penetration, the actual system peak moves to hours later in the day.



2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE ICR-RELATED VALUES FOR THE 2018-2019, 2019-2020 AND 2020-2021 CAPACITY COMMITMENT PERIODS.

A: The ICR-Related Values submitted in this filing are based on the latest available Existing Capacity Resource dataset for the 2018-2019, 2019-2020, and 2020-2021 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 2018-2019, 2019-2020 AND 2020-2021 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 2018-2019, 2019-2020, and 2020-2021 Capacity Commitment Periods.

Table 3 – Qualified Existing Non-Intermittent Generating Capacity Resources Used in the ICR-Related Values Calculations (MW)[12]

Capacity Commitment Period	Summer
2018-2019	30,074
2019-2020	30,336
2020-2021	30,878

Table 4 – Qualified Existing Intermittent Generating Capacity Resources Used in the ICR-Related Values Calculations (MW) [13]

Capacity Commitment Period	Summer	Winter
2018-2019	1,073	1,258
2019-2020	1,017	1,234
2020-2021	912	1,168

Table 5 below 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 2017; and (2) the amount of TTC

[12] 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/2017/10/a6_ara_icr_tie_benefits_1018_2019_2020.zip.

[13] 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.[14] Hence, the Existing Import Capacity Resources shown in Table 5 reflect the Qualified Capacity values of those resources, derated for TTC and the tie benefits values for the 2018-2019, 2019-2020 and 2020-2021 Capacity Commitment Periods.

Table 5 – Derated Qualified Existing Import Capacity Resources Used in the ICR-Related Values Calculation (MW)

Capacity Commitment Period	Summer
2018-2019	1,730
2019-2020	1,510
2020-2021	1,235

Table 6 below 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")[15] Resources.

[14] 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.

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

Table 6 - Existing Demand Resources Used in the ICR-Related Values Calculation (MW)

Capacity Commitment Period	On-Peak	Seasonal Peak	Real-Time Demand Response	Total
2018-2019	1,904	511	620	3,035
2019-2020	2,103	509	781	3,393
2020-2021	2,313	596	765	3,674

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 2012 through December 2016, 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 category is measured by actual response during performance audits and Operating Procedure No. 4 events that occurred in the summer and winter periods of 2012 through 2016. 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 NNE Capacity Zone are shown in the table below for the relevant Capacity Commitment Periods.

Table 7 – N-1 and N-1-1 Transmission Transfer Capability Limits Used in the ICR-Related Values Calculations (MW)

	Boston Import (for NEMA/Boston LSR)		Connecticut Import (for Connecticut LSR)		SEMA-RI Import (for SEMA-RI LSR)		Southeast New England Import (for SENE LSR)		North-South Interface (for NNE 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
2018-2019	4,850	4,175	2,950	1,750	1,280	720	-	-	-
2019-2020	-	-	-	-	-	-	5,700	4,600	-
2020-2021	-	-	-	-	-	-	5,700	4,600	2,725

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 Installed Capacity Requirement, Local Resource Adequacy Requirement, Maximum Capacity Limit, Demand Curve Values and MRI Demand Curves. 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." Using the 1.5% reduction in system load, the assumed voltage reduction load relief values, which offset against the Installed Capacity Requirement, are shown in Table 8 for the summer and winter seasons in each of the Capacity Commitment Periods.

Table 8 – 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
June 2018 - Sept 2018	422
October 2018 - May 2019	313
June 2019 - Sept 2019	421
October 2019 - May 2020	312
June 2020 - Sept 2020	420
October 2020 - May 2021	308

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, Maximum Capacity Limit, Demand Curve Values, and MRI Capacity Demand Curve 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 the Installed Capacity Requirements **c**alculations, 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 2018-2019, 2019-2020 AND 2020-2021 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, Maximum Capacity Limits, Demand Curves Values, and MRI Capacity Demand Curves 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 2018-2019 Capacity Commitment Period, a tie reliability benefits study was performed. For ARA 2 for the 2019-2020 Capacity Commitment Period and ARA 1 for the 2020-2021 Capacity Commitment Period, the associated FCA tie reliability benefits value was utilized in the Installed Capacity Requirements 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 2018-2019 Capacity Commitment Period:

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

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

In the first half of 2017, 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 Installed Capacity Requirements for ARA 3 for the 2018-2019 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 2018-2019, 2019-2020 AND 2020-2021 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 2018-2019 Capacity Commitment Period, ARA 2 for the 2019-2020 Capacity Commitment Period, and ARA 1 for the 2020-2021 Capacity Commitment are shown in Table 10.

Table 10 – Tie Reliability Benefit Assumptions (MW)

	2018-2019 ARA 3	2019-2020 ARA 2	2020-2021 ARA1
Quebec over the Phase-II Interconnection	1,030	975	959
Quebec over the Highgate Interconnection	107	142	145
Maritimes over the New Brunswick Ties	425	519	500
New York over AC Ties	346	354	346
Total	1,908	1,990	1,950

Tie benefits are assumed to not be 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 2018-2019 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 Installed Capacity Requirement for ARA 3 for the 2018-2019 Capacity Commitment Period is the same methodology used to calculate the tie benefits used in the calculation of the Installed Capacity Requirement for the 2018-2019 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.[16] 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, is achieved.

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

A: The Transmission Security Analysis is a deterministic reliability screen of an import-constrained area and is a basic security review set out in Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market, and in Section 3.0 of NPCC's Regional Reliability Reference Directory #1, Design and Operation of the Bulk Power System.[17] 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

[16] 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.

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

interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area load with available existing resources and results are presented under the form of a deterministic operable capacity analysis. This analysis also includes evaluations of both: (1) the loss of the most critical transmission element and the most critical generator ("Line-Gen"), and; (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element ("Line-Line"). Similar deterministic analyses are also used each day by the ISO's System Operations Department to assess the amount of capacity to be committed day-ahead. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine if the removal of a resource that may be retired or de-listed would violate reliability criteria.

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, Demand Curve Values, and MRI Capacity 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, net of BTM PV, 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 peaking generating resources. For peaking 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, no 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 11-13 below show the Local Resource Adequacy Requirements, Transmission Security Analysis Requirements and resulting Local Sourcing Requirements for the relevant Capacity Zones for the 2018-2019, 2019-2020, and 2020-2021 Capacity Commitment Periods.

Table 11 – Import-Constrained Capacity Zone Requirements for 2018-2019 ARA 3 (MW)

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
Connecticut	6,901	7,020	7,020
NEMA/Boston	3,391	2,898	3,391
SEMA-RI	6,439	6,940	6,940

Table 12 **– Import-Constrained Capacity Zone Requirements for 2019-2020 ARA 2 (MW)**

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	9,743	9,473	9,743

Table 1 **– Import-Constrained Capacity Zone Requirements for 2020-2021 ARA 1 (MW)**

Capacity Zone	Transmission Security Analysis Requirement	Local Resource Adequacy Requirement	Local Sourcing Requirement
SENE	9,854	9,560	9,854

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 electrically located within an export-constrained Capacity Zone to meet the regional Installed Capacity Requirement.

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: WHY WAS A MAXIMUM CAPACITY LIMIT NOT CALCULATED FOR ARA 3 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD OR ARA 2 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 3 for the 2018-2019 Capacity Commitment Period or ARA 2 for the 2019-2020 Capacity Commitment Period.

Q. PLEASE DESCRIBE THE MAXIMUM CAPACITY LIMIT FOR THE NNE CAPACITY ZONE FOR ARA 1 FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: For ARA 1 for the 2020-2021 Capacity Commitment Period, the Maximum Capacity Limit for the NNE Capacity Zone is 8,890 MW. This is the amount of capacity resources that can be electrically located within the NNE Capacity Zone, including Import Capacity Resources using the New Brunswick ties for ARA1 for the 2020-2021 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").[18] 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 2018-2019 Capacity Commitment Period, the HQICC value is 1,030 MW for each month of the period.

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[18] *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 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.

For ARA 1 for the 2020-2021 Capacity Commitment Period, the same 959 MW HQICC value utilized for the 2020-2021 Capacity Commitment Period FCA is used for each month of the period.

VII. DEMAND CURVE VALUES AND MRI CAPACITY DEMAND CURVES

Q: WHY WERE DEMAND CURVE VALUES CALCULATED FOR ARA 3 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD AND ARA 2 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 3 for the 2018-2019 Capacity Commitment Period and ARA 2 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 3 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD?

A: Section III.12.1 of Market Rule 1 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." The methodology for determining those values is the same as that used for calculating the Installed Capacity Requirement.

The 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the Demand Curve for ARA 3 for the 2018-2019 Capacity Commitment Period are 32,226 MW and 35,840 MW, respectively.

Q: WHAT ARE THE PRICE ($/KW-MONTH) VALUES ASSOCIATED WITH THE 1-IN-5 LOLE AND 1-IN-87 LOLE CAPACITY REQUIREMENT VALUES FOR THE DEMAND CURVE FOR THE PURPOSE OF CONDUCTING ARA 3 FOR THE 2018-2019 CAPACITY COMMITMENT PERIOD?

A. The price values associated with the 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the demand curve for the purpose of conducting ARA 3 for the 2018-2019 Capacity Commitment Period are $17.728/kW-month and $0/kW-month, respectively.

Q: WHAT ARE THE CAPACITY REQUIRMENT VALUES CALCULATED BY THE ISO FOR THE DEMAND CURVE FOR THE PURPOSES OF CONDUCTING ARA 2 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 for ARA 2 for the 2019-2020 Capacity Commitment Period are 32,379 MW and 36,079 MW, respectively.

Q: WHAT ARE THE PRICE ($/KW-MONTH) VALUES ASSOCIATED WITH THE 1-IN-5 LOLE AND 1-IN-87 LOLE CAPACITY REQUIREMENT VALUES FOR THE DEMAND CURVE FOR THE PURPOSE OF CONDUCTING ARA 2 FOR THE 2019-2020 CAPACITY COMMITMENT PERIOD?

A. The price values associated with the 1-in-5 LOLE and 1-in-87 LOLE capacity requirement values for the demand curve for the purpose of conducting ARA 2 for the 2019-2020 Capacity Commitment Period are $17.296/kW-month and $0/kW-month, respectively.

Q: WHY DID THE ISO DEVELOP MRI CAPACITY DEMAND CURVES FOR ARA 1 FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD?

A: MRI Capacity Demand Curves are calculated starting with the FCA for the 2020-2021 Capacity Commitment Period. Accordingly, the ISO calculated MRI Capacity Demand Curves for ARA 1 for the 2020-2021 Capacity Commitment Period.

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR ARA 1 FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: To calculate the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for SENE, and the Export-Constrained Capacity Zone Demand Curve for NNE for ARA 1 for the 2020-2021 Capacity Commitment Period, the ISO used the MRI methodology, which measures the marginal reliability impact (*i.e.* the MRI), associated with various capacity levels for the system and the Capacity Zones.

To measure the MRI, the ISO uses a performance metric known as "expected energy not served" (or "EENS," which can be described as unserved load). EENS is measured in MWh per year and can be calculated for any set of system and zonal installed capacity levels. The EENS values for system capacity levels are produced by the GE MARS model[19] in 10 MW increments and applying the same assumptions used in determining the Installed Capacity Requirement. These system EENS values are translated into MRI

[19] The GE MARS model is the same simulation system that is already used to develop the Installed Capacity Requirement, Local Resource Adequacy Requirements and Maximum Capacity Limits. For the development of the MRI Demand Curves, the GE MARS model is used to calculate reliability values using 10 MW additions above and 10 MW deductions below the calculated requirements until a sufficient set of values that covers the full range necessary to produce the MRI Demand Curves is determined.

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

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

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

A: In order to satisfy both the reliability needs of the system, which requires that the FCM procure sufficient capacity to meet the 0.1 days per year reliability criterion and produce a sustainable market such that the average market clearing price is sufficient to attract new entry of capacity when needed over the long term, the system and zonal demand curves for ARA 1 for the 2020-2021 Capacity Commitment Period are set equal to the product of their MRI curves and a fixed demand curve scaling factor. The scaling factor is set equal to the lowest value at which the set of demand curves will simultaneously satisfy the planning reliability criterion and pay the estimated cost of new entry ("Net CONE").[20] In other words, the scaling factor is equal to the value which produces a system demand curve that specifies a price of Net CONE at the net Installed Capacity Requirement (Installed Capacity Requirement minus HQICCs).

To satisfy this requirement, the demand curve scaling factor for ARA 1 for the 2020-2021 Capacity Commitment Period was developed for the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone in accordance with Section III.13.2.2.4 of the Tariff. The demand curve scaling factor is set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the LOLE is 0.1 days per year.

Q: PLEASE EXPLAIN THE TRANSITION METHODOLOGY USED TO DEVELOP THE SYSTEM-WIDE CAPACITY DEMAND CURVE FOR ARA 1 FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD.

A: For ARA 1 for the 2020-2021 Capacity Commitment Period, the ISO used the transition provisions in Section III.13.2.2.1 to determine the System-Wide Demand Curve. The transition curve is a hybrid of the previous linear demand curve design and the new MRI-based design.

[20] For ARA 1 for the 2020-2021 Capacity Commitment Period, Net CONE has been determined as $ 11.640/kW-month.

The MRI transition period aims to provide a transition from the linear system-wide capacity demand curve methodology used in FCA 9 and FCA 10 to the MRI-based system-wide capacity demand curve methodology. This transition period will help to provide a stable and consistent market signal while balancing stakeholder interests. The transition period begins with the FCA 11 and may last no longer than three FCAs (and ARAs). If certain conditions relating to net Installed Capacity Requirement growth are met, the transition period will end earlier pursuant to Section III.13.2.2.1 of the Tariff. During the MRI transition period, the System-Wide Capacity Demand Curve is represented as a hybrid of the previous linear demand curve design and the new MRI-based demand curve design.

During the MRI transition period, the System-Wide Capacity Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period shall consist of the following three segments:

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

(2) for prices below $7.03/kw-month, the System-Wide Capacity Demand Curve is represented by a linear segment that runs from a price of $7.03 and a capacity quantity of 35,024MW to a price of $0 and a capacity quantity of 36,640 MW; and

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

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

A*:* For import-constrained Capacity Zones, the Local Resource Adequacy Requirement and Transmission Security Analysis Requirement values both play a role in defining the MRI-based demand curves as they do in setting the Local Sourcing Requirement. Under III.12.2.1.3 of the Tariff, the ISO must determine the MRI value of various capacity levels, for each import-constrained Capacity Zone. For purposes of these calculations, the ISO applies the same modeling assumptions and methodology used to determine the Local Resource Adequacy Requirement except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area is reduced by the greater of: (i) the Transmission Security Analysis Requirement minus the Local Resource Adequacy Requirement, and; (ii) zero. By using a transfer capability that accounts for both the Transmission Security Analysis Requirement and the Local Resource Adequacy Requirement, the ISO applies the same "higher of" logic used in the Local Sourcing Requirement to the derivation of sloped zonal demand curves. For ARA 1 for the 2020-2021 Capacity Commitment Period, the only import-constrained Capacity Zone is SENE and, therefore, there is only one Import-Constrained MRI Capacity Zone Demand Curve.

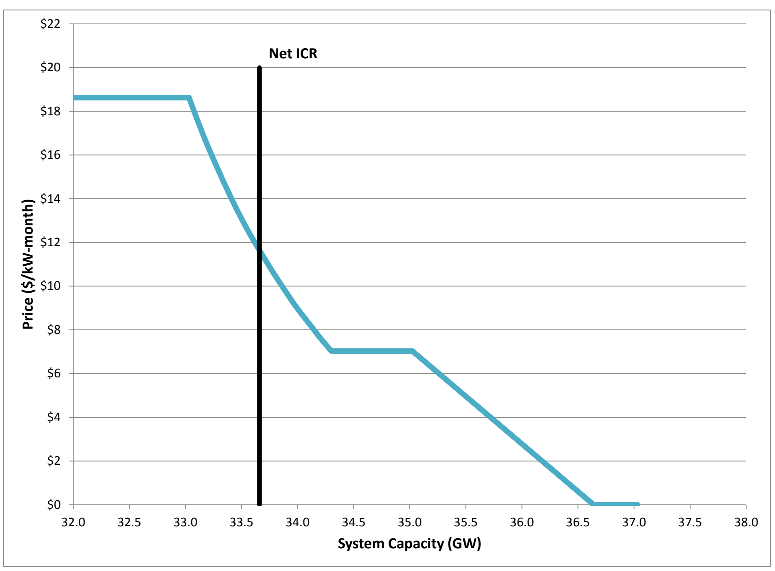
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVE FOR THE NNE CAPACITY ZONE.

A: Under Section III.12.2.2.1 of the Tariff, the Export-Constrained Capacity Zone Demand Curve is calculated using the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's Maximum Capacity Limit. Using the values calculated pursuant to Section III.12.2.2.1 of the Tariff, the ISO must determine the Export-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.3 of the Tariff. For ARA 1 for the 2020-2021 Capacity Commitment Period the only export-constrained Capacity Zone is NNE and, therefore, there is only one Export-Constrained MRI Capacity Zone Demand Curve.

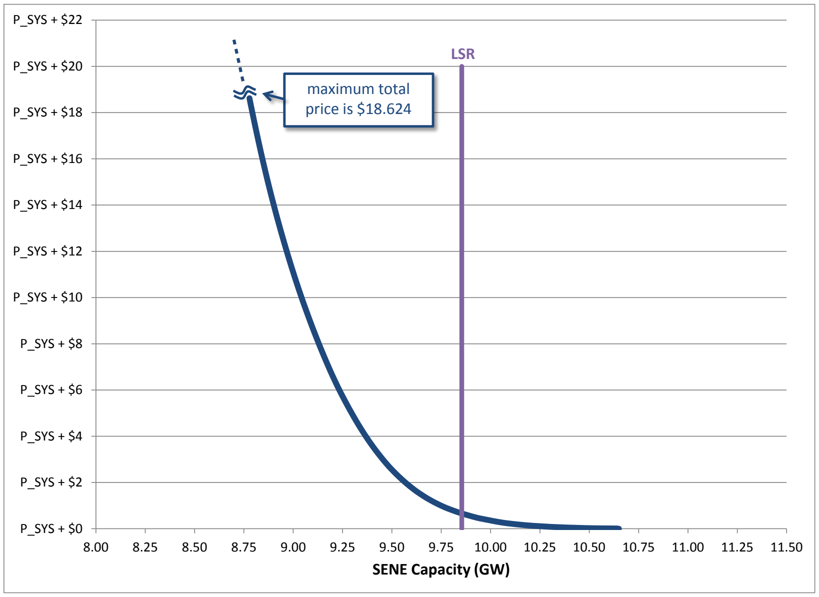
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR ARA 1 FOR THE 2020-2021 CAPACITY COMMITMENT PERIOD?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI Demand Curves for ARA 1 for the 2020-2021 Capacity Commitment Period:

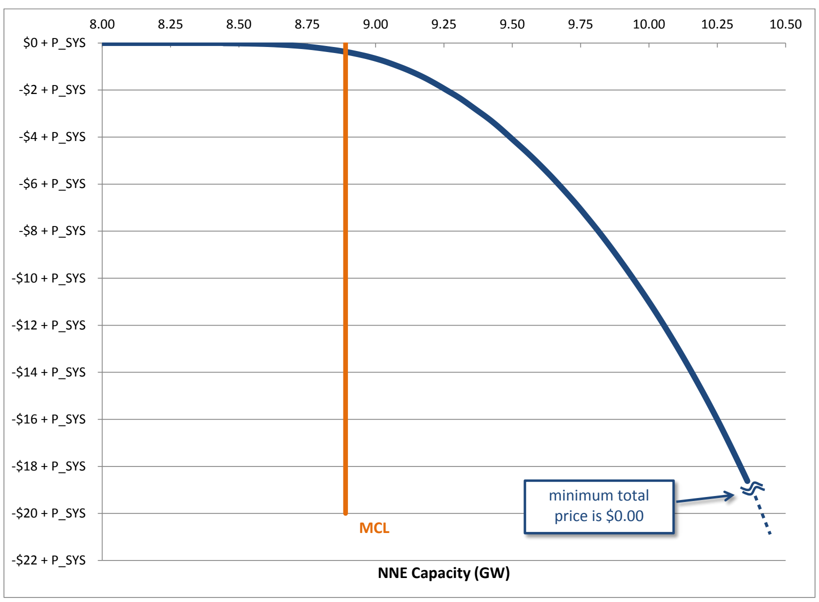
System-Wide Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period



SENE Import-Constrained Capacity Zone Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period



NNE Export-Constrained Capacity Zone Demand Curve for ARA 1 for the 2020-2021 Capacity Commitment Period



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/28/17

Carissa Sedlacek

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