November 5, 2019

VIA ELECTRONIC FILING

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

Re: *ISO New England Inc.*, Docket No. ER20-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the Fourteenth FCA (Associated with the 2023-2024 Capacity Commitment Period)

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO") hereby electronically submits to the Federal Energy Regulatory Commission ("FERC" or "Commission") this transmittal letter and related materials that identify the following values for the 2023-2024 Capacity Commitment Period,[2] which is associated with the fourteenth Forward Capacity Auction ("FCA 14"): (i) Installed Capacity Requirement ("ICR");[3] (ii) Local Sourcing Requirement ("LSR") for the Southeast New England ("SENE") Capacity Zone;[4] (iii) Maximum Capacity Limits ("MCLs") for the Maine Capacity Zone and the Northern New England ("NNE") Capacity Zone;[5] (iv) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (v) Marginal Reliability Impact ("MRI") Demand Curves.[6] The ICR, LSR for the SENE Capacity Zone, MCLs for the Maine Capacity Zone and the NNE Capacity Zone, HQICCs, and

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[1] 16 U.S.C. § 824d (2019).

[2] The 2023-2024 Capacity Commitment Period starts on June 1, 2023 and ends on May 31, 2024.

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

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

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

[6] As explained in this filing letter, the MRI Demand Curves include the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone, and the Export-Constrained Capacity Zone Demand Curves for the NNE and the Maine Capacity Zones.

MRI Demand Curves are collectively referred to herein as the "ICR-Related Values." [7]

The Mystic 8 and 9 generating facility ("Mystic 8 & 9") has been retained for fuel security for FCA 14. Mystic 8 & 9 has until January 10, 2020 to decide whether to retire or continue to operate in the 2023-2024 Capacity Commitment Period.[8] For that reason, the ISO is filing two sets of ICR-Related Values. The first set assumes that Mystic 8 & 9 will continue to operate in the 2023-2024 Capacity Commitment Period, and, accordingly, includes Mystic 8 & 9 in the model. The second set assumes that Mystic 8 & 9 will retire and, accordingly, does not include Mystic 8 & 9 in the model. The body of this filing letter describes the set of proposed ICR-Related Values with Mystic 8 & 9 in the model. The alternative set of values, *i.e.* the ICR-Related Values without Mystic 8 & 9 in the model, are included in Attachment 1 to this filing. Notably, the differences between the values are very small:

- The ICR without Mystic 8 & 9 in the model[9] is 7 MW higher than the ICR with Mystic 8 & 9 in the model.[10]
- The LSR for the SENE Capacity Zone without Mystic 8 & 9 in the model[11] is 197 MW lower than the LSR for the SENE Capacity Zone with Mystic 8 & 9 in the model.[12]
- The MCL for the Maine Capacity Zone without Mystic 8 & 9 in the model[13] is 70 MW lower than the MCL for the Maine Capacity Zone with Mystic 8 & 9 in the model.[14]

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[7] Pursuant to Section III.12.3 of the Tariff, the ICR must be filed 90 days prior to the applicable Forward Capacity Auction ("FCA"). FCA 14, which is the primary FCA for the 2023-2024 Capacity Commitment Period, is scheduled to commence on February 3, 2020.

[8] Under a cost-of-service agreement filed with the Commission, the Mystic 8 & 9 generating facility has until January 10, 2020, to decide whether it will continue to operate in CCP 14, or whether instead it will accept only a one-year retention and retire at the end of the 2022-2023 Capacity Commitment Period, which is associated with FCA 13. *See* Constellation Mystic Power, LLC, Amendment No. 1 to Rate Schedule FERC No. 1, Docket No. ER19-1164-000 (filed March 1, 2019), at Section 2.2.3 of the Amended and Restated Cost-of-Service Agreement.

[9] 33,438 MW (the ICR without Mystic 8 & 9 in the model net of 943 MW of HQICCs is 32,495 MW).

[10] 33,431 MW (the ICR with Mystic 8 & 9 in the model net of 941 MW of HQICCs is 32,490 MW).

[11] 9,560 MW

[12] 9,757 MW

[13] 3,950 MW

[14] 4,020 MW

- The MCL for the NNE Capacity Zone without Mystic 8 & 9 in the model[15] is 70 MW lower than the MCL for the NNE Capacity Zone with Mystic 8 & 9 in the model.[16]

The graphical representations of both sets of ICR-Related Values' MRI Demand Curves are virtually identical.

The ISO is proposing the following ICR-Related Values with Mystic 8 & 9 modeled:

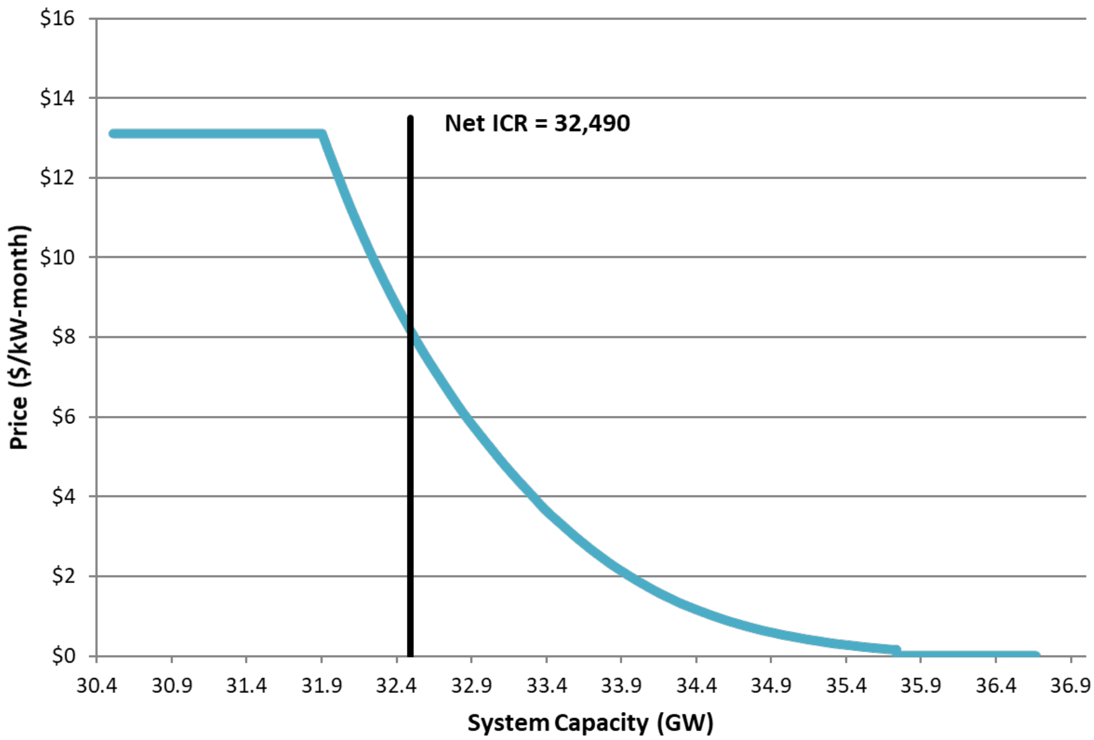
ICR (net of HQICCs)	32,490 MW
LSR for SENE Capacity Zone	9,757 MW
MCL for Maine	4,020 MW
MCL for NNE	8,445 MW
HQICCs	941 MW

Along with the following MRI Demand Curves with Mystic 8 & 9 modeled:

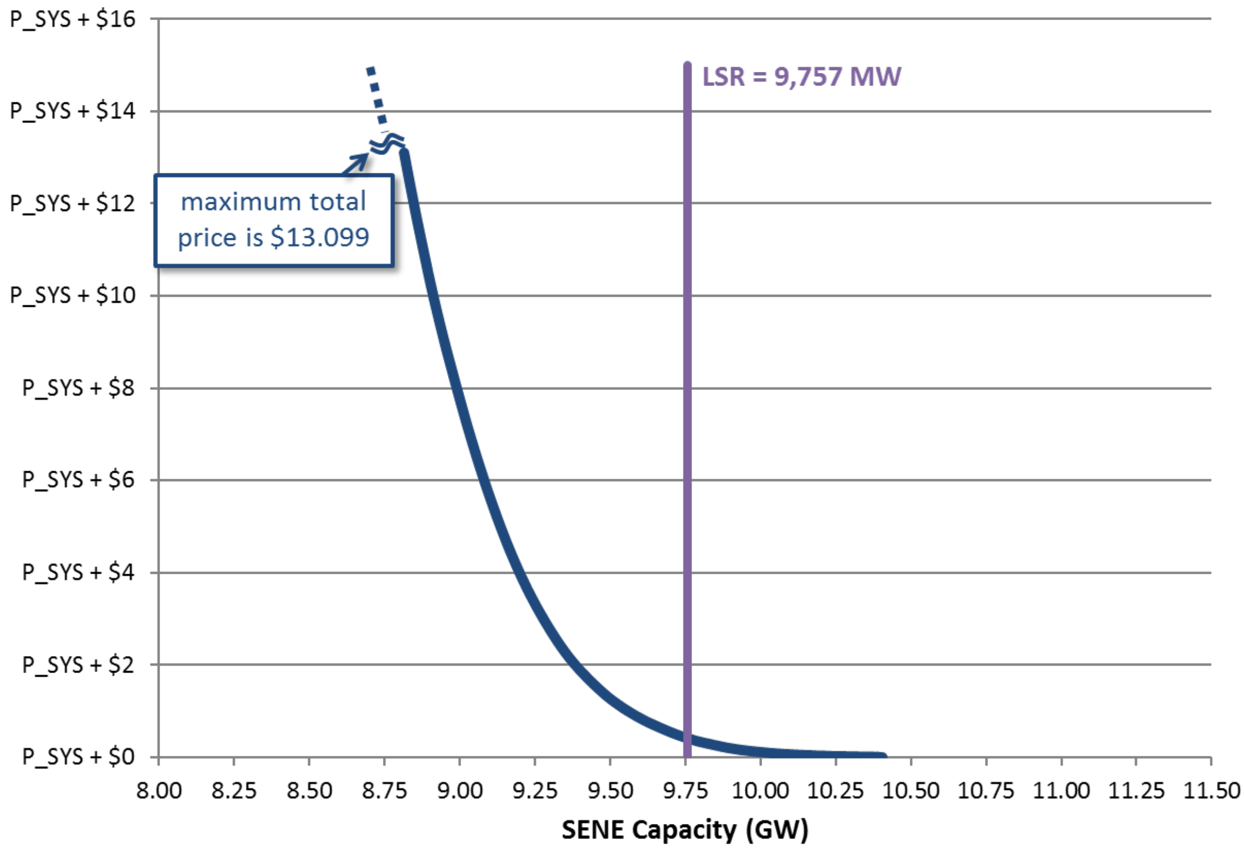
[15] 8,375 MW

[16] 8,445 MW

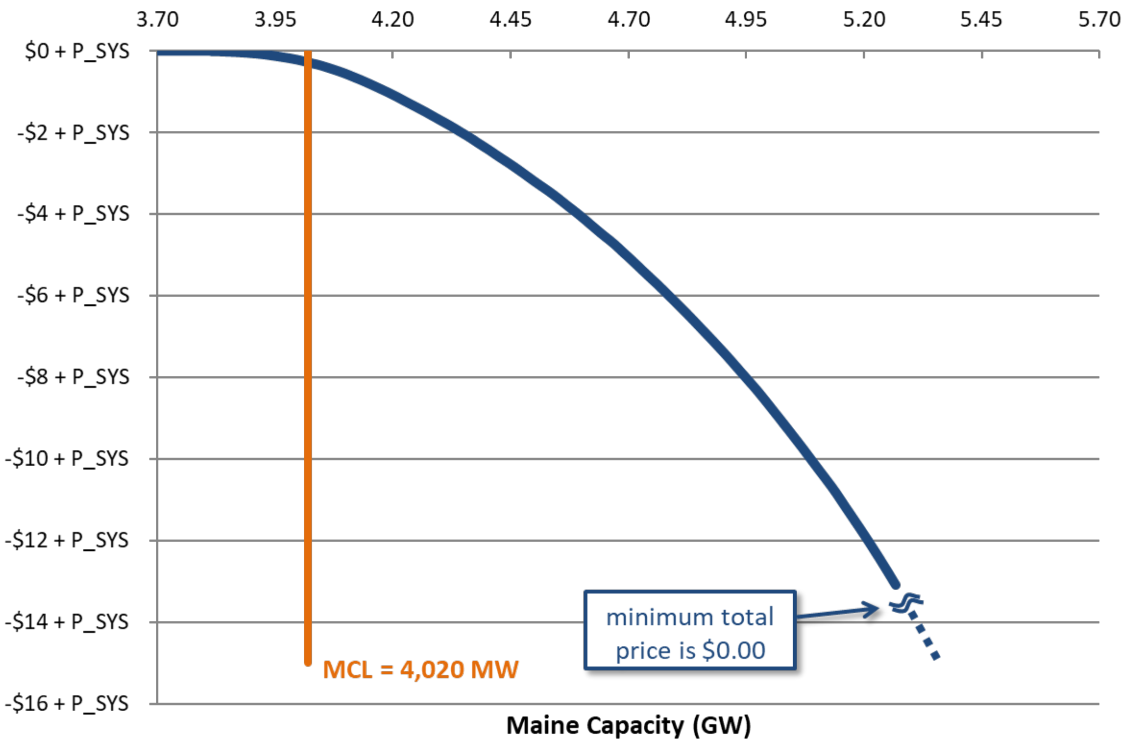
1. System-Wide Capacity Demand Curve for FCA 14



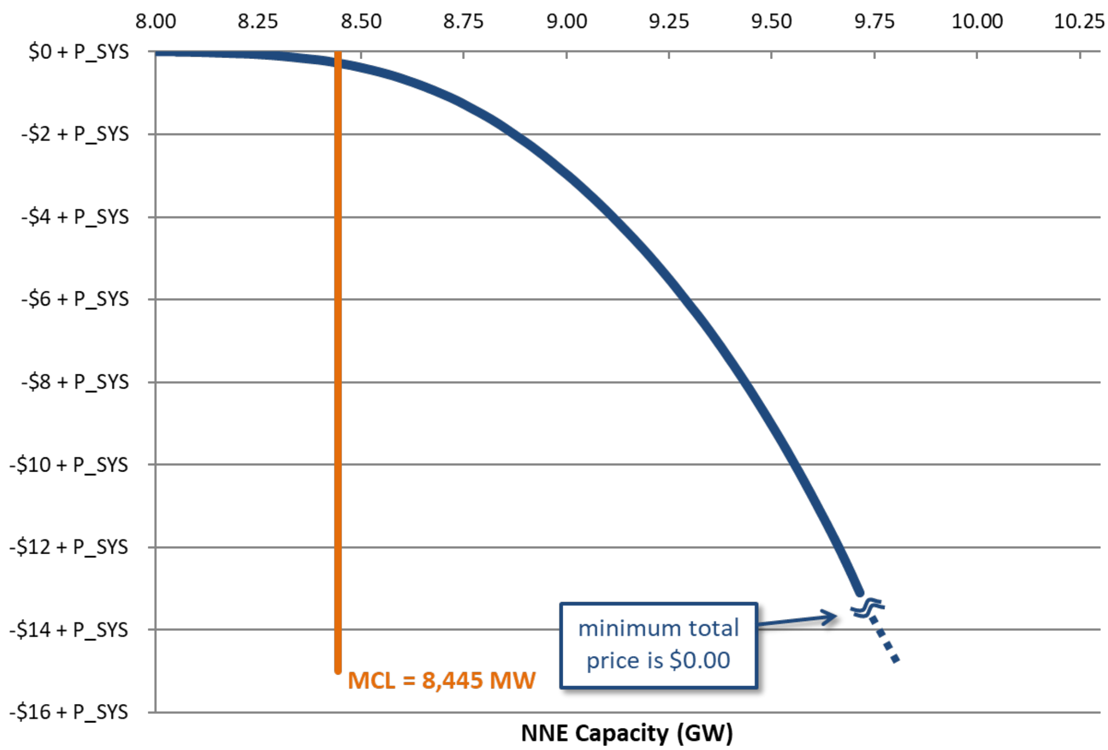
2. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 14



3. Export-Constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 14



4. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 14



The derivation of the ICR-Related Values is discussed in Sections III-VI of this filing letter, in the attached joint testimony of Carissa Sedlacek, Director of Planning Services in the ISO's System Planning Department and Peter Wong, Manager, Resource Studies & Assessments in the ISO's System Planning Department (the "Sedlacek-Wong Testimony"), and in the attached testimony of Jonathan Black, Manager, Load Forecasting in the System Planning Department (the "Black Testimony").

Starting in 2019, the voltage reduction assumption[17] used in the calculation of the probabilistically-calculated ICR-Related Values[18] is a load reduction of 1% from implementation

[17] Pursuant to Section III.12.7.4 of the Tariff, load and capacity relief expected from system-wide implementation of certain actions specified in ISO New England Operating Procedure No. 4 – Action During a Capacity Deficiency ("OP-4") must be included in the calculation of the probabilistic ICR-Related Values. Voltage reduction is one of the actions of OP-4.

[18] The ICR, Local Resource Adequacy Requirement ("LRA") (which is an input in the LSR), MCL, MRI values and HQICCs are probabilistically calculated.

of 5% voltage reductions (it was previously 1.5%). Also starting in 2019, the Equivalent Forced Outage Rate - Demand ("EFORd") will be used in the modeling of peaking generation resources in the Transmission Security Analysis ("TSA") (previously, a 20% deterministic adjustment factor was used as the outage rate for peaking generating resources in the TSA). The Tariff changes that effected the modifications to these two assumptions were filed with the Commission on November 15, 2018.[19] The Commission accepted the Tariff changes on January 8, 2019,[20] with an effective date of January 14, 2019. In addition, this year, there are improvements in the long-term forecast methodology (described in Section III.B.1.a of this filing letter and in the Black Testimony).[21] The rest of the methodology used to calculate the ICR-Related Values is the same Commission-approved methodology that was used to calculate the values submitted and accepted for preceding FCAs.[22] The proposed values are therefore the result of a well-developed process that improves, pursuant to the Commission's direction, on the processes utilized and approved by the Commission for the development of the ICR and related values in the past.[23] Accordingly, the Commission should accept the proposed values as just and reasonable without change to become effective on January 4, 2020.

I. DESCRIPTION OF FILING PARTY AND COMMUNICATIONS

The ISO is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates and plans 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

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[19] *ISO New England Inc.*, Filing of Updates to Assumptions Used in the Installed Capacity Requirement and Related Values, Docket No. ER19-343-000, (filed Nov. 15, 2018).

[20] *ISO New England Inc.*, Docket No. ER19-343-000 (Jan. 8, 2019) (delegated letter order).

[21] By design, the load forecast methodology is not contained in the Tariff. Accordingly, Tariff changes are not needed to effect the improvements in the load forecast methodology. *See ISO New England Inc.*, 154 FERC ¶ 61,008 (2016); *order on reh'g*, 155 FERC ¶ 61,145 (2016).

[22] FERC orders approving prior ICR filings: 2022-2023 ICR: *ISO New England Inc.*, Docket No. ER19-291-000 (Jan. 8, 2019) (delegated letter order); 2021-2022 ICR: *ISO New England Inc.*, Docket No. ER18-263-000 (Dec. 18, 2017) (delegated letter order); 2020-2021 ICR: *ISO New England Inc.*, Docket No. ER17-320-000 (Dec. 6, 2017) (delegated letter order); 2019-2020 ICR: *ISO New England Inc.*, 154 FERC ¶ 61,008 (2016), *order on reh'g*, 155 FERC ¶ 61,145 (2016); 2018-2019 ICR: *ISO New England Inc.*, 150 FERC ¶ 61,003 (2015), *order on reh'g*, 150 FERC ¶ 61,155 (2015); 2017-2018 ICR: *ISO New England Inc.*, Docket No. ER14-328-000 (Dec. 30, 2013) (delegated letter order); 2016-2017 ICR: *ISO New England Inc.*, Docket No. ER13-334-000 (Dec. 31, 2012) (delegated letter order); 2015-2016 ICR: *ISO New England Inc.*, Docket No. ER12-756-000 (Feb. 23, 2012) (delegated letter order); 2014-2015 ICR: *ISO New England Inc.*, Docket No. ER11-3048-000, 135 FERC ¶ 61,135 (2011); 2013-2014 ICR: *ISO New England Inc.*, Docket No. ER10-1182-000 (June 25, 2010) (delegated letter order); 2012-2013 ICR: *ISO New England Inc.*, Docket No. ER09-1415-000 (Aug. 14, 2009) (delegated letter order); 2011-2012 ICR: *ISO New England Inc.*, 125 FERC ¶ 61,154 (2008).

[23] *Id*.

Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC").

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

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II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, pursuant to Section 205 of the Federal Power Act, which "gives a utility the right to file rates and terms for services rendered with its assets."[24] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[25] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[26] 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."[27] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[28] 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.[29]

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

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

[26] *Id.* at 9.

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

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

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

III. INSTALLED CAPACITY REQUIREMENT

A. Description of the ICR

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

The ISO is proposing an ICR of 33,431 MW for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period. This value reflects tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Quebec in the aggregate amount of 1,940 MW. However, the 33,431 MW ICR value does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 941 MW per month is applied to reduce the portion of the ICR that is allocated to the Interconnection Rights Holders ("IRH"). Thus, the net ICR, after deducting the HQICC value, is 32,490 MW.[30]

B. Development of the ICR

Starting in 2019, the voltage reduction assumption used in the calculation of the probabilistically-calculated ICR-Related Values will be 1% load relief (it was previously 1.5%). Also starting in 2019, the EFORd will be used in the modeling of peaking generation resources in the TSA (previously, a 20% deterministic adjustment factor was used as the outage rate for peaking generating resources in the TSA). In addition, this year, there are improvements in the long-term forecast methodology. With the exception of the aforementioned modifications, the calculation methodology used to develop the ICR-Related Values for FCA 14 is the same as that used to calculate the values for previous FCAs.

As in previous years, the values submitted in the instant filing are based on assumptions relating to expected system conditions for the associated 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, load reduction from implementation

[30] The net ICR is used in the development of the MRI Demand Curves, which will be used to procure capacity in FCA 14.

of 5% voltage reductions, and a minimum level of operating reserve.[31] The modeling assumptions have been updated to reflect expected changes in system conditions since the development of the ICR and related values for FCA 13. These updated assumptions are described below.

1. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2023-2024 Capacity Commitment Period are one major input into the calculation of the ICR-Related Values. For the purpose of calculating the ICR for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, the ISO used the load forecast published in the 2019-2028 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2019 ("2019 CELT Report").[32] The ISO developed the 2019 CELT Report's load forecast by using an improved methodology (described below) to determine load forecasts and develop the peak load assumptions. As in previous years, the methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee ("LFC").[33]

The projected New England Control Area summer 50/50 peak load[34] for the 2023-2024 Capacity Commitment Period is 28,838 MW. In determining the ICR, the load forecast is represented by a weekly probability distribution of daily peak loads. This probability distribution is meant to quantify the New England weekly system peak load's relationship to weather. The 50/50 peak load is used solely for reference purposes. In the ICR calculations, the methodology determines the amount of capacity resources needed to meet every expected peak load of the weekly distribution given the probability of occurrence associated with that load level.[35]

a. 2019 Updates to the Long-Term Load Forecast

Pursuant to Section III.12.8 of the Tariff, the ISO is required to forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecast must be based on appropriate models and data inputs. For the first time since 2013, New England experienced several non-holiday weekdays with peak-eliciting weather during the

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[31] Sedlacek-Wong Testimony at 13.

[32] *Id.* at 14-15.

[33] The methodology is reviewed periodically and updated when deemed necessary in consultation with the LFC.

[34] The New England Control Area is a summer-peaking system, meaning that the highest load occurs during the summer. The 50/50 peak refers to the peak load having a 50% chance of being exceeded. The value shown is the 2019 CELT "*Net Forecast – With Reductions for BTM PV*" peak load forecast.

[35] *See* Sedlacek-Wong Testimony at 14-15.

2018 summer season. For this reason, and in furtherance of the requirements of Section III.12.8 of the Tariff, in 2019, the ISO evaluated its peak demand load forecast model.[36] The analysis of the forecast performance for the summer of 2018 showed that the observed peak loads were lower than the CELT 2018 forecasts given the weather conditions. To address these performance issues, the ISO incorporated the improvements described below in the gross demand modeling.[37]

In the summer model specification, a second weather variable, cooling degree days ("CDD") was incorporated in addition to weighted temperature-humidity index ("WTHI"). This improvement was made to mitigate forecast performance issues identified during extreme weather conditions that took place during the 2018 summer.[38] Also, for monthly peak demand modeling, separate July and August monthly models were developed. Given that forecasts of energy are one of the input variables within peak demand models, monthly demand models were developed to be consistent with the conversion to monthly energy modeling incorporated in CELT 2019.[39] In the winter demand model specification, a second weather variable, heating degree days ("HDD") was incorporated, and the dry bulb temperature variable used in CELT 2018 was replaced with "effective temperature," which is a wind speed adjusted temperature.[40] Finally, the historical weather period used to generate probabilistic forecasts was shortened from 40 years to 25 years. The new 25-year period covers 1991 to 2015. This change was made primarily because the new winter demand model incorporates wind speed data, which was not available for all of the years of the former 40-year period used (*i.e.*, 1975 to 2014).[41]

In addition to the improvements to the long-term forecast methodology, the daily peak load and weather for the historical period covering 2004-2018 was used as the model estimation period (2003-2017 was used the previous year). This is a standard update to the forecast cycle that is done every year.[42]

In 2019, the ISO discussed its development of the CELT forecast with the LFC and the PAC. The discussions with the LFC took place at the LFC meetings on December 14, 2018,

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[36] Black Testimony at 6.

[37] *Id.* at 7.

[38] *Id.* at 9-12.

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

[40] The new winter demand model was presented to and discussed with the LFC and the Planning Advisory Committee ("PAC"). However, because the winter demand model does not have an impact on the ICR, it was not presented to the PSPC or the Reliability Committee. *See* Black Testimony at 9.

[41] *Id.* at 13.

[42] *Id.* at 14-17.

February 11, 2019, and March 29, 2019. The ISO provided the PAC with updates on the development of the forecast at both its March 21, 2019 and April 25, 2019 meetings. Relative to the development of the ICR-Related Values, the forecast was also discussed at four Power Supply Planning Committee ("PSPC") meetings on July 25, 2019, August 9, 2019, August 26, 2019, and September 9, 2019. The ISO further discussed the CELT 2019 forecast at the August 20, 2019 and September 10, 2019 Reliability Committee meetings.[43]

b. Estimated Impacts of the Updates to the 2019 Long-Term Forecast on the net ICR

As described in the Sedlacek-Wong Testimony, the estimated impacts of the updates to the 2019 long-term forecast on the net ICR were derived thru simulations using preliminary load forecast data prior to finalizing the 2019 CELT forecast. While the loads used are very close to the 2019 CELT forecast, they are not exactly the same. The simulations were done earlier in the process to provide stakeholders with the estimated impacts of the improvements to the long-term forecast methodology and the change in the historical period used in the model estimation. The estimated impacts presented to stakeholders are as follows:

		Estimated Impacts on net ICR (MW)
Changes to Gross Load Forecast for CCP 2023-2024	**Forecast Cycle Case**	**-300**
	Second Weather Variable Case	**-855**
	Separate July and August Peak Load Model Case	**+45**
	Shorter History Weather Period Case	**-140**
	All Changes Together	**-1,250**

[43] *See* Black Testimony at 17-18, which provides links to the ISO presentations for each meeting.

2. Resource Capacity Ratings

The ICR for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, is based on the latest available resource ratings[44] of Existing Capacity Resources that have qualified for FCA 14 at the time of the ICR calculation. These resources are described in the qualification informational filing for FCA 14 that is being submitted concurrently to the Commission on November 5, 2019.[45]

Resource additions and most resource attritions[46] are not assumed in the calculation of the ICR for FCA 14, pursuant to the Tariff, because there is no certainty regarding which new resource additions or existing resource attritions, if any, will clear the FCA. The use of the proxy unit for potential required resource additions when the system is short of capacity, and the additional load carrying capability ("ALCC") adjustments to remove surplus capacity from the system, discussed in the Sedlacek-Wong Testimony, are designed to address these resource addition and attrition uncertainties.[47]

3. Resource Availability

The proposed ICR value for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, reflects generating resource availability assumptions based on historical scheduled maintenance and forced outages of these capacity resources.[48] For generating resources, individual unit scheduled maintenance assumptions are based on each unit's most recent five-year historical average of scheduled maintenance. The individual generating resource's forced outage assumptions are based on the resource's most recent five-year historical NERC Generator Availability Database System ("GADS") forced outage rate data submitted to

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[44] The resource capacity ratings for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, were calculated in accordance with Section III.12.7.2 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved ICRs for the first thirteen primary FCAs. *See* 2022-2023 ICR Letter Order; the 2021-2022 ICR Letter Order; the 2020-2021 ICR Letter Order; the 2019-2020 ICR Letter Order; the 2018-2019 ICR Letter Order; the 2017-2018 ICR Letter Order; the 2016-2017 ICR Letter Order; and the 2015-2016 ICR Letter Order.

[45] *ISO New England Inc.*, Informational Filing for Qualification in the Forward Capacity Market, filed on November 5, 2019 at Attachment C.

[46] Retirement De-List Bids that are at or above the FCA Starting Price and those retirements for resources that have elected unconditional treatment are deducted from the Existing Capacity Resources' qualified capacity data.

[47] Sedlacek-Wong Testimony at 12-13.

[48] The assumed resource availability ratings for FCA 14 which is associated with the 2023-2024 Capacity Commitment Period, are discussed in the Sedlacek-Wong Testimony. The ratings were calculated in accordance with Section III.12.7.3 of the Tariff using the methods and procedures that were employed for calculating resource capacity ratings reflected in the Commission-approved ICRs for the first thirteen primary FCAs. *See* note 22, *supra*.

the ISO. If the resource has been in commercial operation less than five years, then the NERC class average maintenance and forced outage data for the same class of units is used to substitute for the missing annual data.

The Qualified Capacity of an Intermittent Power Resource is the resource's median output during the Reliability Hours averaged over a period of five years. Based on the Intermittent Power Resources rating methodology, these resources are assumed to be 100% available because their availability impacts on reliability are already incorporated into the resource ratings.

In the ICR calculations, availability assumptions for passive Demand Resources are modeled as 100% available. Active Demand Capacity Resources' availability are based on actual responses during all historical OP-4 events and ISO performance audits that occurred in summer and winter 2014 through 2018.

4. Other Assumptions

a. Tie Benefits

New England's Commission-approved method for establishing the ICR requires that assumptions be made regarding the tie benefits value to be used as an input in the calculation.[49] The tie benefits reflect the assumed amount of emergency assistance from neighboring Control Areas that New England could rely on, without jeopardizing reliability in New England or the neighboring Control Areas, in the event of a capacity shortage in New England. Assuming tie benefits as a resource to meet the 0.1days/year LOLE criterion reduces the ICR and lowers the amount of capacity to be procured in the FCA.

The ICR for FCA 14 proposed by the ISO reflects tie benefits calculated from the Quebec, New Brunswick, and New York Control Areas.[50] The ISO utilizes a probabilistic multi-area reliability model to calculate total tie benefits from these three Control Areas. Tie benefits from each individual Control Area are determined based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas. Specifically, the tie

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[49] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for FCA 14 is the same methodology used to calculate the tie benefits used in the ICR for Capacity Commitment Periods associated with prior FCAs.

[50] *See* 2014-2015 ICR Filing, Sedlacek-Wong Testimony at 29, for an explanation of the methodology employed by the ISO in determining tie benefits for the 2015-2016 Capacity Commitment Period, which was also employed by the ISO in determining tie benefits for the 2015-2016 Capacity Commitment Period, the 2016-2017 Capacity Commitment Period, the 2017-2018 Capacity Commitment Period, the 2018-2019 Capacity Commitment Period, the 2019-2020 Capacity Commitment Period, the 2020-2021 Capacity Commitment Period, the 2021-2022 Capacity Commitment Period, and the 2022-2023 Capacity Commitment Period.

benefits methodology is comprised of two broad steps. In step one, the ISO develops necessary system load, transmission interface transfer capabilities and capacity assumptions. In step two, the ISO conducts simulations using the probabilistic GE MARS modeling program in order to determine tie benefits. In this step, the neighboring Control Areas are modeled using "*at criteria*" modeling assumptions which means that, when interconnected, all Control Areas are assumed to be at the 0.1 days/year reliability planning criteria.

The tie benefits methodology is described in detail in Section III.12.9 of the Tariff. [51] The procedures associated with the tie benefits calculation methodology were also addressed in detail in the transmittal letter for the 2014-2015 ICR Filing.[52] The total tie benefits assumption and a breakdown of this value by Control Area is as follows:

Control Area	Tie Line	Tie Benefits (MW)
Quebec	Phase II	941
Quebec	Highgate	136
New Brunswick	New Brunswick	501
New York	NY AC Ties	362
New York	Cross Sound Cable	0
	Total tie benefits	**1,940**

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 2019, the transfer limits of these external interconnections were reviewed based on the latest available information regarding forecasted topology and load forecast information, and it was determined that no changes to the established external interface limits were warranted. The ISO established the following capacity transfer capability values for each interconnection including their assumed forced and scheduled outage rates:

External Tie Line	Capacity Transfer Capability (MW)	Forced Outage Rate (%)	Maintenance (Weeks)
External Interfaces Total	3,700	N/A	N/A
Phase II	1,400	0.9	3.2
Highgate	200	0.1	1.2
New Brunswick	700	0	3.2

[51] Sedlacek-Wong Testimony at 27.

[52] *ISO New England Inc.*, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for the 2014-2015 Capability Year, Docket No. ER11-3048-000 at 13-19 (2011).

NY AC Ties	1,400	0.5	5.3
Cross Sound Cable	0	0	6.0

The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the ICR for FCA 14, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.[53]

b. Amount of System Reserves

Pursuant to Section III.12.7.4 (c) of the Tariff, the amount of system reserves included in the determination of the ICR and related values must be consistent with those needed for reliable system operations during emergency conditions. Using a system reserve assumption in the ICR and related values calculations assumes that, during peak load conditions, under extremely tight capacity situations, while emergency capacity and energy operating plans are being used, ISO operations would have available the essential amount of operating reserves for transmission system protection, system load balancing, and tie control, prior to invoking manual load shedding. Starting in FCA 13, the ISO determined that the amount of reserves to be assumed in the determination of the ICR and related values should be 700 MW. As a result, 700 MW of system reserves is the amount that the ISO used in the determination of the ICR-Related Values for FCA 14.

IV. LOCAL SOURCING REQUIREMENTS AND MAXIMUM CAPACITY LIMITS

In the Forward Capacity Market ("FCM"), the ISO must also calculate LSRs and MCLs. An LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone to meet the ICR.[54] An MCL is the maximum amount of capacity that can be located in an export-constrained Capacity Zone to meet the ICR.[55] The general purpose of LSRs and MCLs is to identify capacity resource needs such that, when considered in combination with the transfer capability of the transmission system, they are electrically distributed within the New England Control Area contributing toward purchasing the right amount of resources in the FCA to meet NPCC's and the ISO's bulk power system reliability planning criteria.

For FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, the ISO calculated the following values for the SENE Capacity Zone using the methodology that is

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[53] Sedlacek-Wong Testimony at 32.

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

[55] *Id.*

reflected in Section III.12.2 of the Tariff:

Import	LRA	TSA	LSR
SENE	9,525 MW	9,757 MW	9,757 MW

The calculation methodology for determining the LSR utilizes both LRA criteria as well as criteria used in the TSA that the ISO uses to maintain system reliability when reviewing de-list bids for a FCA. Because the system ultimately must meet both resource adequacy and transmission security requirements, the LSR provisions state that both resource adequacy and transmission security-based requirements must be developed for each import-constrained zone. Specifically, the LSR is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the LRA or (ii) the TSA requirement.[56]

The LRA is addressed in Section III.12.2.1.1 of the Tariff. It is a zonal capacity requirement calculated using a probabilistic modeling technique that ensures the zone has sufficient resources to meet the one-day-in-ten years reliability standard. The LRA analysis assumes the same set of resources used in the calculation of the ICR.

The calculation of the TSA requirement is addressed in Section III.12.2.1.2 of the Tariff, and the conditions used for completing the TSA within the FCM are documented in Section 6 of ISO Planning Procedure No. 10, Planning Procedure to Support the Forward Capacity Market ("PP-10").[57] The TSA uses static transmission interface transfer limits, developed based on a series of discrete transmission load flow study scenarios, to evaluate the transmission import-constrained area's reliability. Using the analysis, the ISO identifies a resource requirement sufficient to allow the system to operate through stressed conditions.[58] The TSA utilizes the same set of data underlying the load forecast, resource capacity ratings and resource availability that are used in probabilistically determining the ICR, MCL, and LRA. However, due to the deterministic and transmission security-oriented nature of the TSA, some of the assumptions utilized in performing the TSA differ from the assumptions used in calculating the ICR, MCL and other aspects of the LRA. These differences relate to the manner in which load forecast data, and OP-4 action events are utilized in the TSA. These differences are described in more detail in the Sedlacek-Wong Testimony.[59]

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

[57] Copy available at https://www.iso-ne.com/static-assets/documents/2019/05/pp-10-r23-053119.pdf

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

[59] Sedlacek-Wong Testimony at 37.

For FCA 14, the ISO also calculated the MCLs for the Maine and NNE Capacity Zones. The MCLs were calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff. The MCLs for the Maine and NNE Capacity Zones are as follows:

Capacity Zone	MCL
Maine	4,020 MW
NNE	8,445 MW

V. HQICCs

HQICCs are capacity credits that are allocated to the IRH, which are the entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[60] 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 the IRH in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each Capacity Commitment Period's FCA. The HQICC value for FCA 14 is 941 MW per month.

VI. MRI DEMAND CURVES

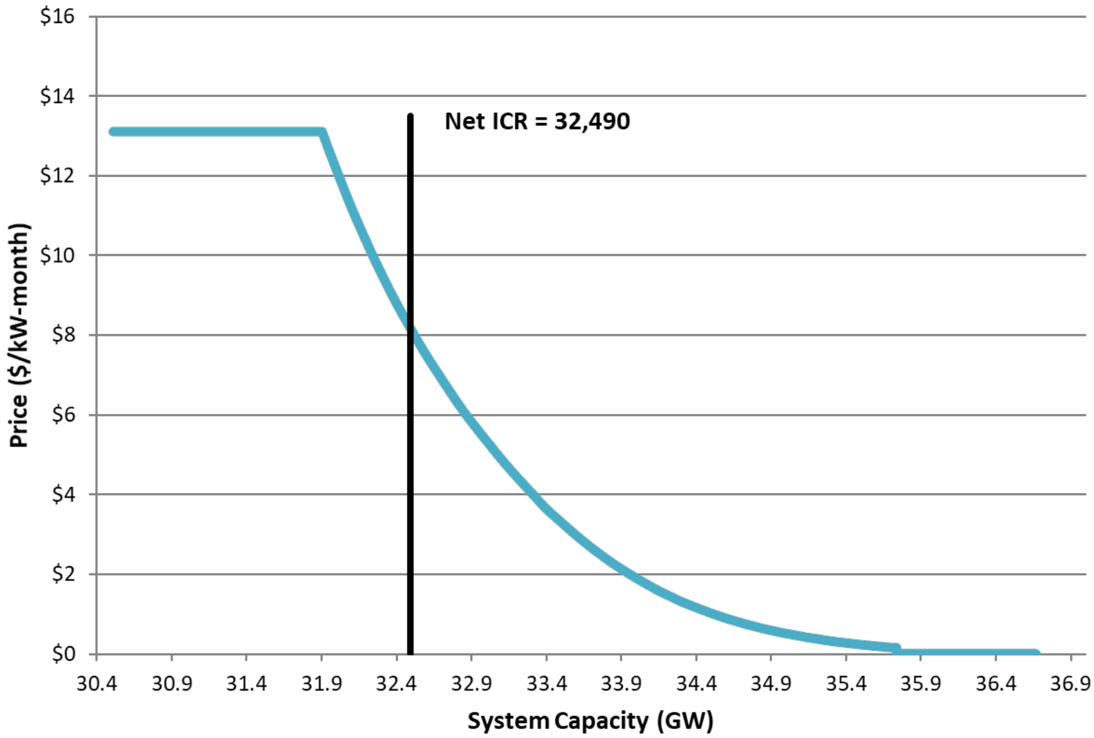
Starting with FCA 11, which was associated with the 2020-2021 Capacity Commitment Period, the ISO began using the MRI Demand Curve methodology to develop system-wide and zonal demand curves to be used in the FCA to procure needed capacity. Accordingly, as described below, the ISO has developed system-wide and zonal MRI demand curves to be used in FCA 14.

A. System-Wide Capacity Demand Curve

Under Section III.12.1.1 of the Tariff, prior to each FCA, the ISO must determine the system-wide MRI of capacity at various higher and lower capacity levels for the New England Control Area. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used in determining the ICR. Using the values calculated pursuant to Section III.12.1.1.1, the ISO must determine the System-Wide Capacity

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

Demand Curve pursuant to Section III.13.2.2.1 of the Tariff.[61]



B. Import-Constrained Capacity Zone Demand Curves

Under Section III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels around the requirement, for each import-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the LRA pursuant to Section III.12.2.1.1, except that the capacity transfer capability between the Capacity Zone under study and the rest of the New England Control Area determined pursuant to Section III.12.2.1.1(b) has to be reduced by the greater of: (i) the TSA Requirement minus the LRA, and; (ii) zero. Using the values calculated pursuant to Section III.12.2.1.3 of the Tariff, the ISO must determine the Import-Constrained Capacity Zone Demand Curves pursuant to Section III.13.2.2.2 of the Tariff. For FCA 14, there is one import-constrained Capacity Zone and

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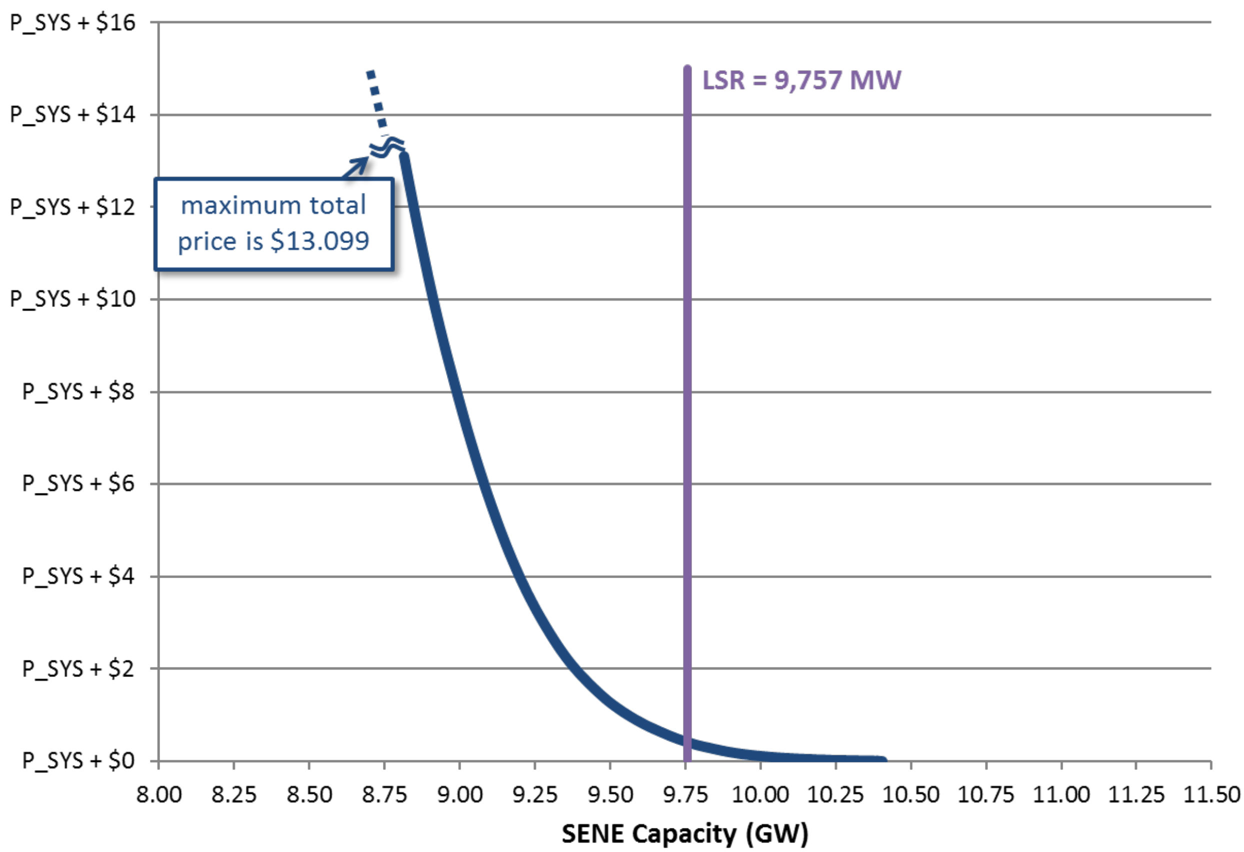
[61] Additional details regarding the calculation of the System-Wide Capacity Demand Curve are included in the Sedlacek-Wong Testimony at 42-45.

therefore, there is one Import-Constrained Capacity Zone Demand Curve.

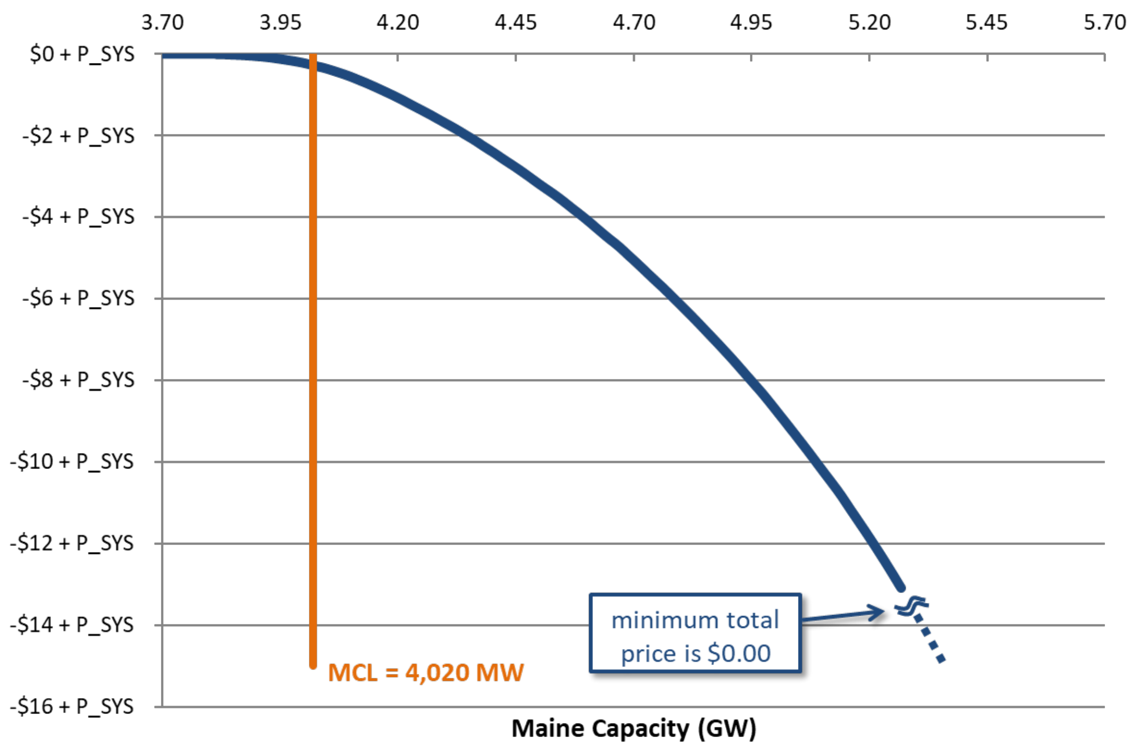
The following is the Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 14:



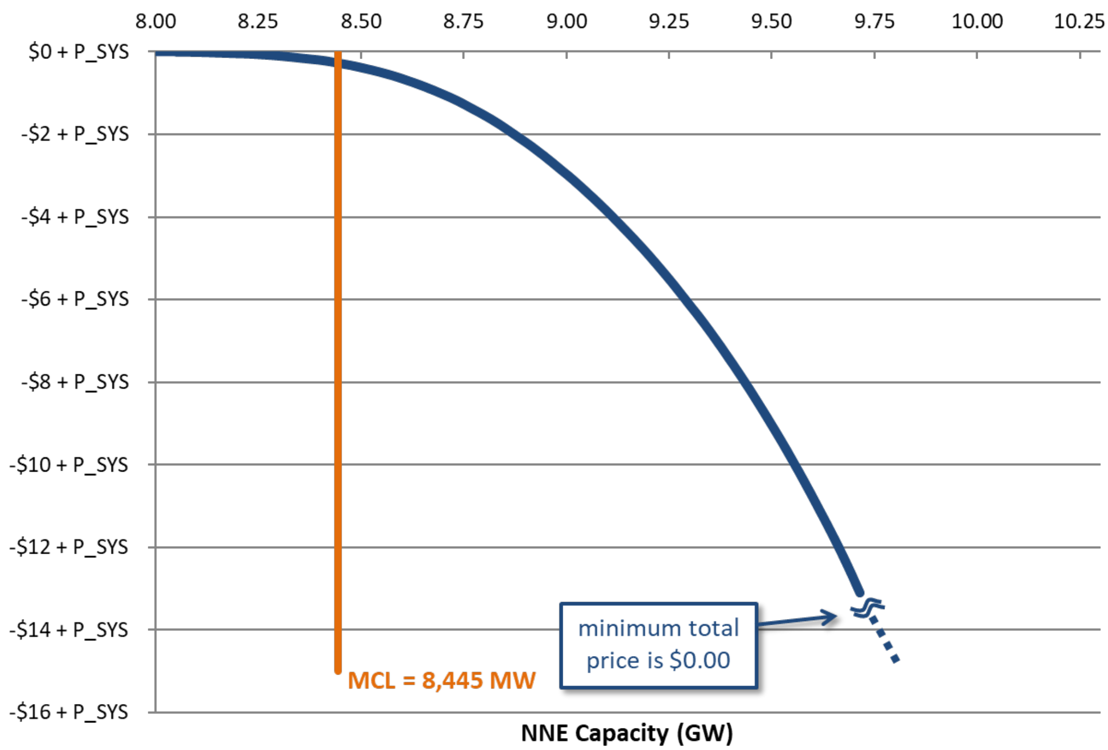
C. Export-Constrained Capacity Zone Demand Curves

Under Section III.12.2.2.1 of the Tariff, prior to each FCA, the ISO must determine the MRI of capacity, at various higher and lower capacity levels around the requirement, for each export-constrained Capacity Zone. For purposes of calculating these MRI values, the ISO must apply the same modeling assumptions and methodology used to determine the export-constrained Capacity Zone's MCL. 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 FCA 14, there are two Export-Constrained Capacity Zone Demand Curves.

The following is the Export-Constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 14:



The following is the Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 14:



VII. STAKEHOLDER PROCESS

The ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR-Related Values for FCA 14 through an extensive stakeholder process over the course of six months, during which the PSPC and the Reliability Committee reviewed the calculation assumptions and methodologies, and discussed the proposed ICR-Related Values for FCA 14.

In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[62] Among other responsibilities, NESCOE is responsible for providing feedback on the proposed ICR-Related Values at the relevant NEPOOL PSPC, Reliability Committee and

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

Participants Committee meetings, and was in attendance for most meetings at which the ICR-Related Values for FCA 14 were discussed.[63]

On September 25, 2019, the Reliability Committee voted to recommend, by a show of hands, that the Participants Committee support the HQICCs, both with and without Mystic 8 & 9. Also on September 25, 2019, the Reliability Committee did not recommend that the Participants Committee support the rest of the proposed ICR-Related Values (*i.e.* the ICR, LSR for the SENE Capacity Zone, MCLs for the Maine and NNE Capacity Zones, and MRI Demand Curves) both with and without Mystic 8 & 9. Both motions resulted in a vote of 49.65% in favor and failed to reach the 60% required for a recommendation of support.

On October 4, 2019, the Participants Committee voted in support of the HQICCs both with and without Mystic 8 & 9. Both votes passed by a show of hands (with oppositions and abstentions recorded). Pursuant to Section 11.4 of the Participants Agreement, the Participants Committee also took advisory votes on the rest of the proposed ICR-Related Values calculated with and without Mystic 8 & 9 (*i.e.* the ICR, LSR for the SENE Capacity Zone, MCLs for the Maine and NNE Capacity Zones, and MRI Demand Curves). The motion to support the values with Mystic 8 & 9 failed to meet the 60% required for a recommendation of support with 59.97% in favor. The motion to support the values without Mystic 8 & 9 also failed to meet the 60% required for a recommendation of support with 59.66% in favor.

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for FCA 14 to be effective on January 4, 2020 (which is 60 days from the filing date), so that the proposed values can be used as part of FCA 14, which will be conducted in February 2020.

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for FCA 14 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.[64] 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.

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

[64] 18 C.F.R. § 35.13.

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

- This transmittal letter;
- Attachment 1: Set of ICR-Related Values without Mystic 8 & 9 in the model
- Attachment 2: Joint Testimony of Carissa Sedlacek and Peter Wong;
- Attachment 3: Testimony of Jonathan Black;
- Attachment 4: List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been emailed.

35.13(b)(2) – The ISO respectfully requests that the Commission accept this filing to become effective on January 4, 2020.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at https://www.iso-ne.com/participate/participant-asset-listings/directory?id=1&type=committee. An electronic copy of this transmittal letter and the accompanying materials has also been sent to the governors and electric utility regulatory agencies for the six New England states which comprise the New England Control Area, and to the New England Conference of Public Utility Commissioners, Inc. The names and addresses of these governors and regulatory agencies are shown in Attachment 2. In accordance with Commission rules and practice, there is no need for the entities identified on Attachment 2 to be included on the Commission's official service list in the captioned proceedings unless such entities become intervenors in this proceeding.

35.13(b)(4) - A description of the materials submitted pursuant to this filing is contained in this transmittal letter.

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

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

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

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

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in order to supply service with respect to the proposed ICR and related values.

X. CONCLUSION

The ISO requests that the Commission accept the two sets of proposed ICR-Related Values reflected in this submission for filing without change to become effective January 4, 2020. When FCA 14 is conducted, the ISO will only use the set of values that reflect Mystic 8 & 9's decision on whether to continue to operate in the 2023-2024 Capacity Commitment Period.

Respectfully submitted,

ISO NEW ENGLAND INC.

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Attachments

cc : Entities listed in Attachment 4

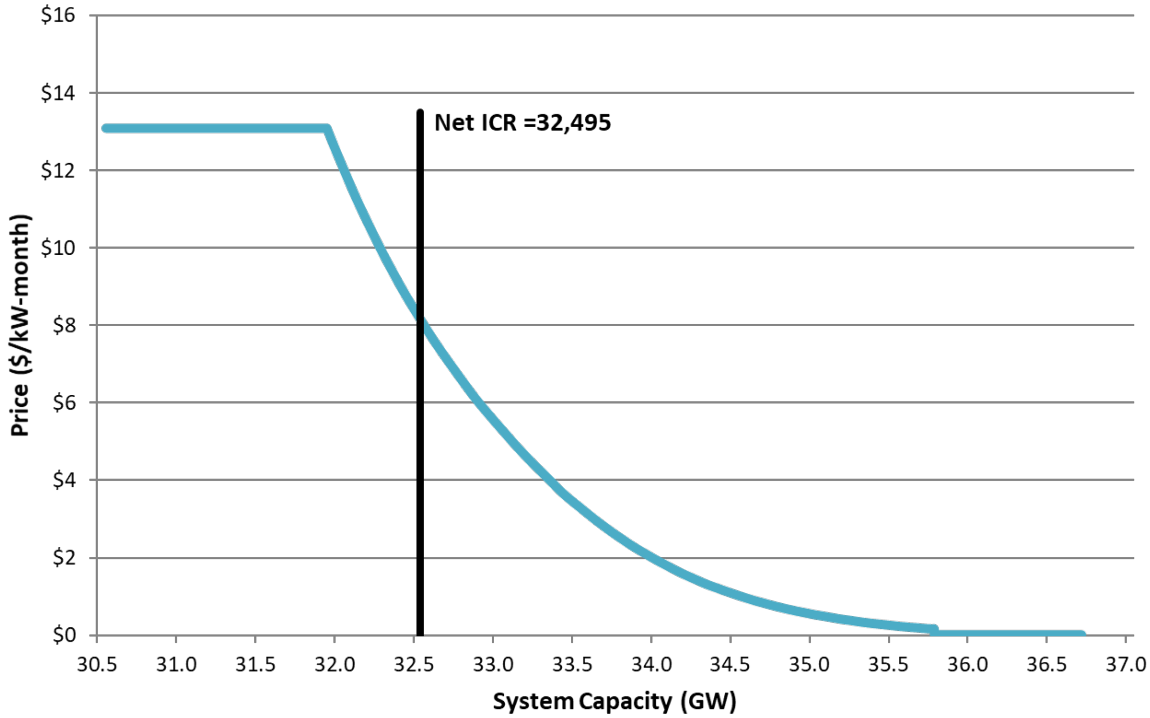
Attachment 1

ISO Proposed ICR Values for CCP 2023-2024 (FCA 14) (MW) without Mystic 8 & 9 in the Model

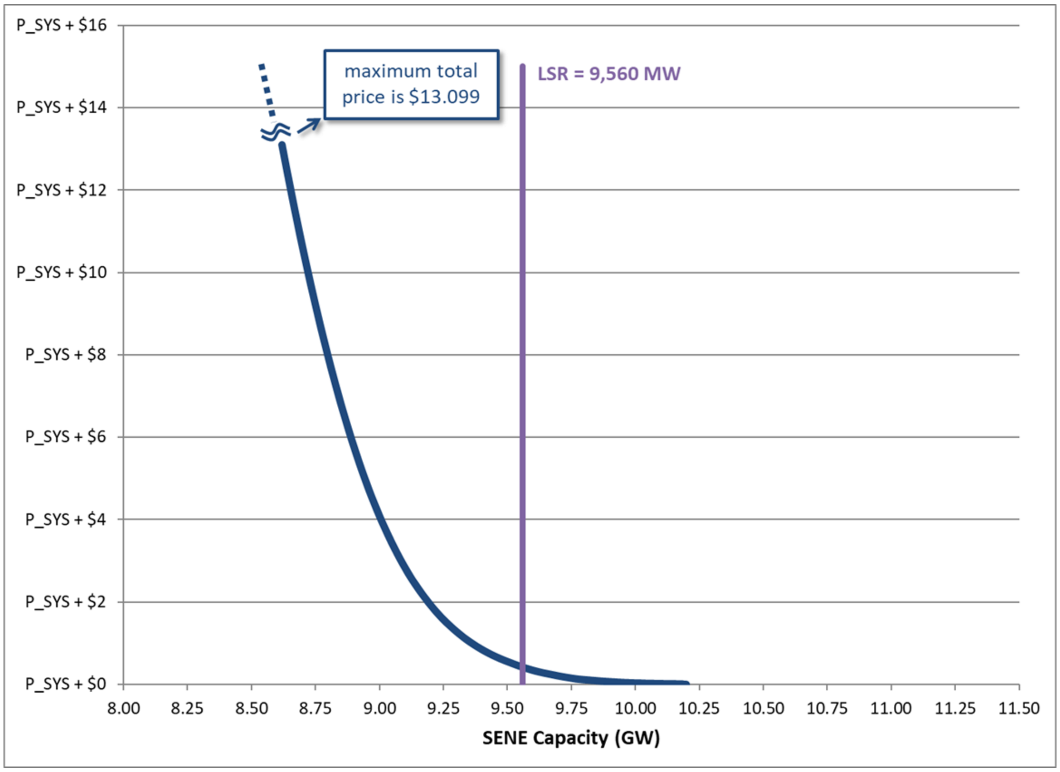
2023-2024 FCA 14	New England	Southeast New England	Maine	Northern New England
Peak Load (50/50) net of BTM PV	28,838	12,540	2,117	5,430
Existing Capacity Resources	33,224	9,515	3,456	8,270
Installed Capacity Requirement	33,438			
HQICCs	943			
Net ICR (ICR minus HQICCs)	32,495			
Local Sourcing Requirement		9,560		
Maximum Capacity Limit			3,950	8,375

- The Existing Capacity Resources value reflects the existing resources with Qualified Capacity for FCA 14 at the time of the ICR calculation and reflects applicable retirements and terminations
- 50/50 peak load net of behind-the-meter photovoltaic shown for informational purposes

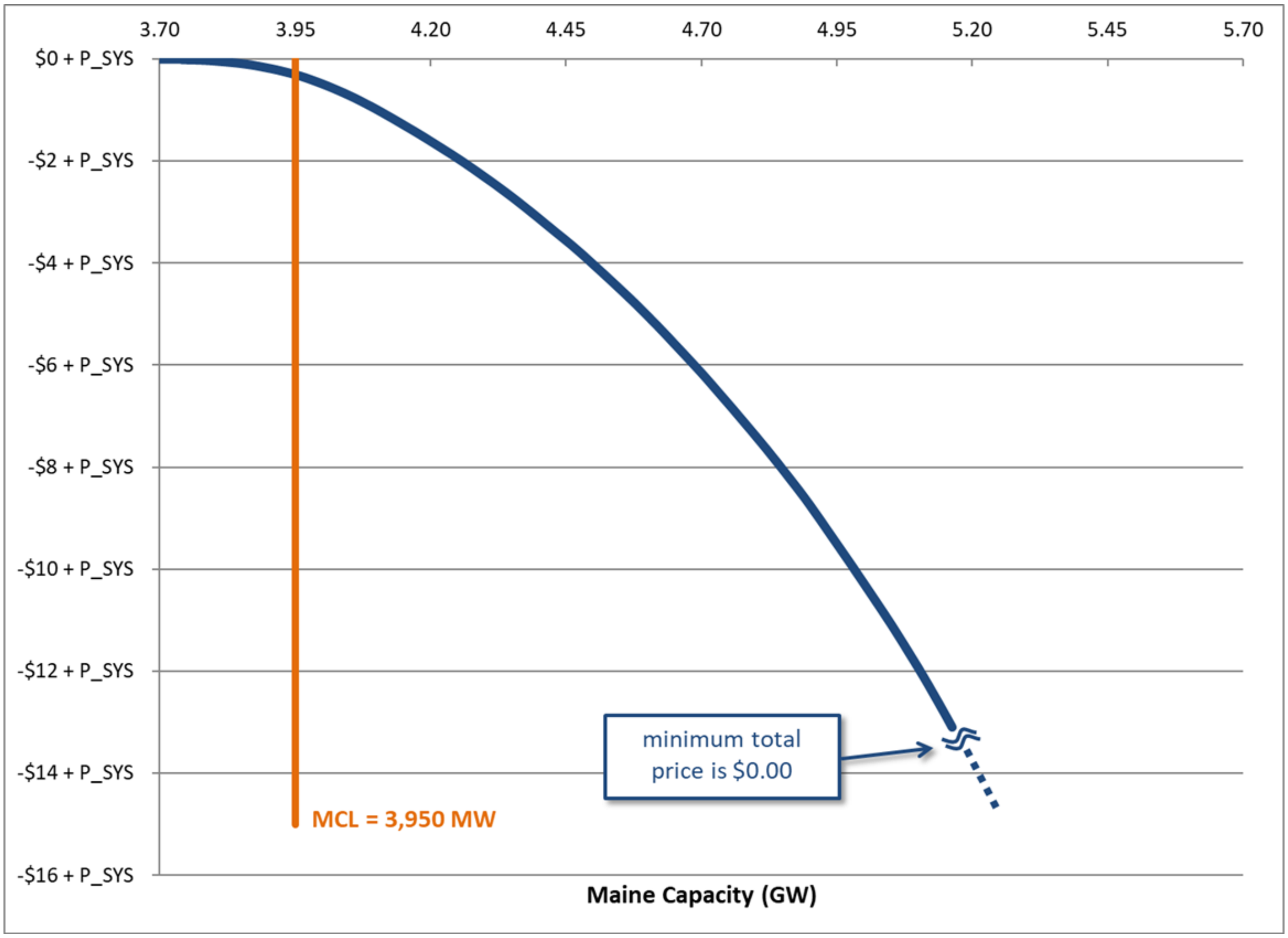
FCA 14 System-Wide Demand Curve without Mystic 8 & 9 in the Model



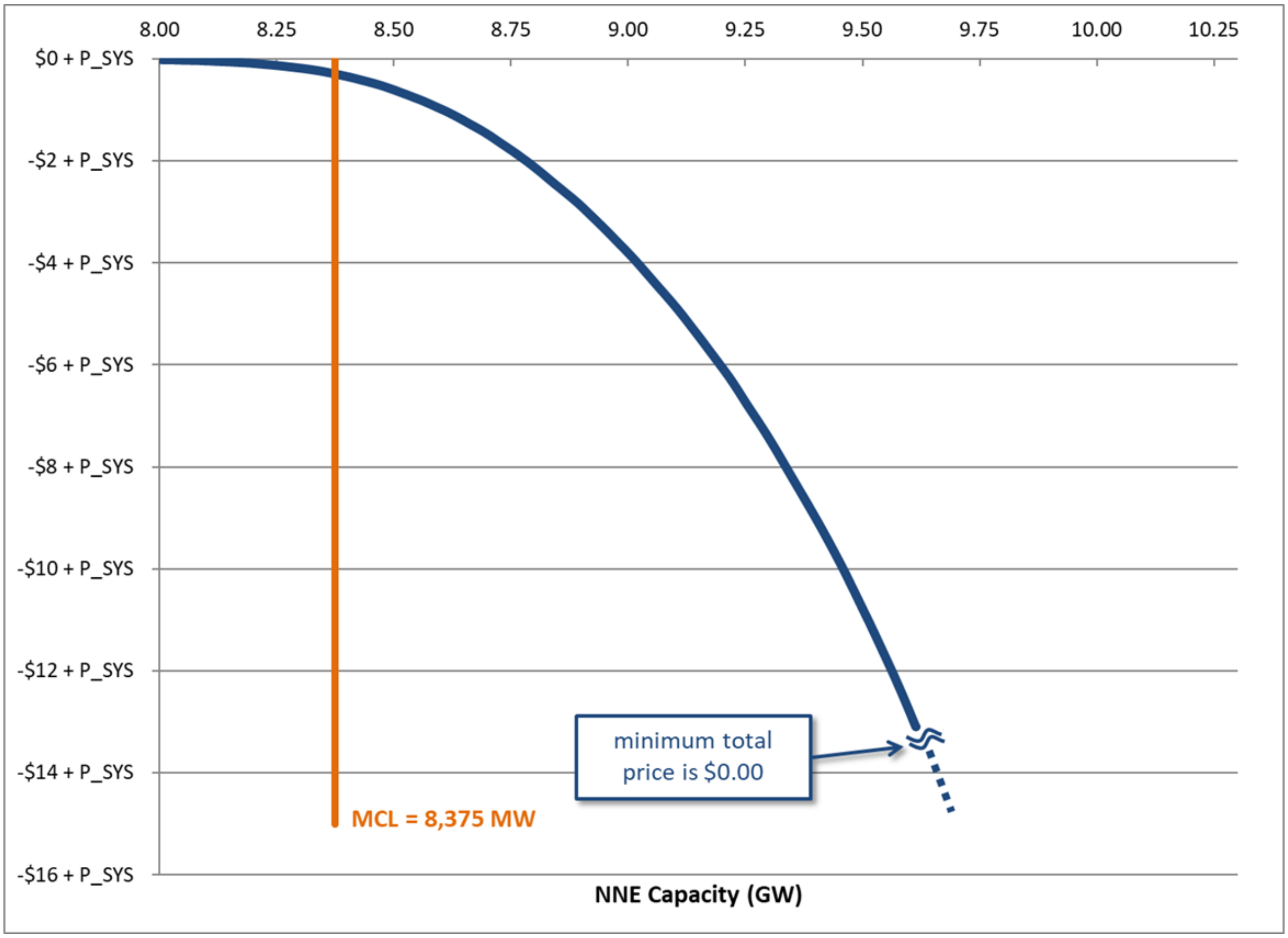
FCA 14 SENE Import-Constrained Capacity Zone Demand Curve without Mystic 8 & 9 in the Model



FCA 14 Maine Export-Constrained Capacity Zone Demand Curve without Mystic 8 & 9 in the Model



FCA 14 NNE Export-Constrained Capacity Zone Demand Curve without Mystic 8 & 9 in the Model



Attachment 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER20-___-000**

PREPARED TESTIMONY OF
MS. CARISSA SEDLACEK and MR. PETER WONG
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

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

Mr. Wong: My name is Peter Wong. I am Manager, Resource Studies & Assessments in the System Planning Department at the ISO. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

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

A: I am currently Director of Planning Services in the System Planning Department at the ISO. Before I held this position, I was Director of Resource Adequacy from 2015 to 2019. In my current position, I have overall responsibility for the development of the Installed Capacity Requirement ("ICR") and related values for all auctions. 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. As Director of Resource Adequacy, I was also responsible for the resource qualification processes for new and existing resources in the FCM; 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.

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 capacity 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 an M.B.A. from State University of New York at Buffalo.

Q: MR. WONG, PLEASE DESCRIBE YOUR CURRENT RESPONSIBLITIES AND EXPERIENCE.

A: I am currently Manager of Resource Studies and Assessments in the System Planning Department at the ISO. I have been the manager of the resource adequacy group responsible for the calculation of the ICR and associated values, including the development of the assumptions used in the calculations, since 1999. Before that, I served for about seven years as the Manager of Operations Planning & Analysis for the staff of the New England Power Exchange ("NEPEX"), the power pool operator that preceded the ISO, and then for the ISO once it was established.

I have worked at the ISO and its predecessor for more than 40 years. During this time, in addition to my most recent duties described above, I have held various positions in the Power Supply Planning department of New England Power Planning ("NEPLAN"). My last position at NEPLAN was Manager of Power Supply Planning. During my 15 years with NEPLAN Power Supply Planning, I was involved in all matters related to Objective Capability (which is now referred to as the ICR) and resource adequacy. I also have served as the Chair of the New England Power Pool ("NEPOOL")[1] Power Supply Planning Committee, the NEPOOL technical committee that assists the ISO in the review

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

and development of all assumptions used for the calculation and development of ICRs, Local Sourcing Requirements, Transmission Security Analysis Requirements, Local Resource Adequacy Requirements and Maximum Capacity Limits for New England.

Q: WHAT IS THE PURPOSE OF THIS TESTIMONY?

A: This testimony discusses the derivation of the ICR, the Local Sourcing Requirement ("LSR") for the Southeast New England (SENE) Capacity Zone, the Maximum Capacity Limits ("MCLs") for the Maine Capacity Zone and the Northeast New England (NNE) Capacity Zone,[2] the Hydro-Quebec Interconnection Capability Credits ("HQICCs"), and the Marginal Reliability Impact ("MRI") Demand Curves for the 2023-2024 Capacity Commitment Period, which is the Capacity Commitment Period associated with the fourteenth Forward Capacity Auction to be conducted beginning on February 3, 2020 ("FCA 14"). The 2023-2024 Capacity Commitment Period starts on June 1, 2023 and ends on May 31, 2024. The ICR, the LSR for the SENE Capacity Zone, the MCLs for

[2] As explained in the ISO's Informational Filing for FCA 14, which is being submitted to the Federal Energy Regulatory Commission ("Commission") concurrently with this filing, in accordance with Section III.12.4. of the ISO New England Transmission, Markets and Services Tariff ("Tariff"), the ISO determined that it will model four Capacity Zones in FCA 14: the SENE Capacity Zone, the Maine Capacity Zone, the NNE Capacity Zone and the Rest of Pool Capacity Zone. The SENE Capacity Zone includes the Southeastern Massachusetts ("SEMA"), Rhode Island and Northeastern Massachusetts ("NEMA")/Boston Load Zones. The SENE Capacity Zone will be modeled as an import-constrained Capacity Zone. The NNE Capacity Zone includes the New Hampshire, Vermont and Maine Load Zones. The Maine Load Zone will be modeled as a separate nested export-constrained Capacity Zone within NNE. NNE will be modeled as an export-constrained Capacity Zone. The Rest-of-Pool Capacity Zone includes the Connecticut and Western/Central Massachusetts Load Zones.

the Maine Capacity Zone and the NNE Capacity Zone, HQICCs and MRI Demand Curves for FCA 14 are collectively referred to herein as the "ICR-Related Values."

Q: PLEASE EXPLAIN WHY TWO SETS OF VALUES ARE BEING SUBMITTED TO THE COMMISSION THIS YEAR.

A: The Mystic 8 and 9 generating facility ("Mystic 8 & 9") has been retained for fuel security for FCA 14. Mystic 8 & 9 has until January 10, 2020 to decide whether to retire or continue to operate in the 2023-2024 Capacity Commitment Period.[3] For that reason, the ISO is filing two sets of ICR-Related Values. The first set assumes that Mystic 8 & 9 will continue to operate in the 2023-2024 Capacity Commitment Period, and, accordingly, includes Mystic 8 & 9 in the model used to simulate the ICR-Related Values. The second set assumes that Mystic 8 & 9 will retire and, accordingly, does not include Mystic 8 & 9 in the model.

Q: WHICH SETS OF VALUES WILL YOUR TESTIMONY DESCRIBE?

A: Our testimony will describe the set of proposed ICR-Related Values with Mystic 8 & 9 in the model. The alternative set of values, *i.e.* the ICR-Related Values without Mystic 8 & 9 in the model, are included in Attachment 1 to this filing.

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[3] Under a cost-of-service agreement filed with the Commission, the Mystic 8 & 9 generating facility has until January 10, 2020, to decide whether it will continue to operate in CCP 14, or whether instead it will accept only a one-year retention and retire at the end of the 2022-2023 Capacity Commitment Period, which is associated with FCA 13. *See* Constellation Mystic Power, LLC, Amendment No. 1 to Rate Schedule FERC No. 1, Docket No. ER19-1164-000 (filed March 1, 2019), at Section 2.2.3 of the Amended and Restated Cost-of-Service Agreement.

Q: PLEASE DESCRIBE THE DIFFERENCES BETWEEN THE TWO SETS OF VALUES.

A: The differences in the values are very small, as shown in the table below.

Table 1 – Comparison of ICR-Related Values Without Mystic 8 & 9 in the Model and ICR-Related Values With Mystic 8 & 9 (MW) in the Model

	Values Without Mystic 8 & 9 in the Model	Values With Mystic 8 & 9 in the Model	Impact of Including Mystic 8 & 9 in the Model
ICR	33,438	33,431	7 MW lower
HQICCs	943	941	2 MW lower
Net ICR (net of HQICCs)	32,495	32,490	5 MW lower
LSR for SENE	9,560	9,757	197 MW higher
MCL for Maine	3,950	4,020	70 MW higher
MCL for NNE	8,375	8,445	70 MW higher

Q: WHICH SET OF VALUES WILL THE ISO USE IN FCA 14?

A: The ISO will use the set of values that reflects Mystic 8 & 9's decision on whether to continue to operate for the 2023-2024 Capacity Commitment Period.

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

A. Starting in 2019, the voltage reduction assumption[4] used in the calculation of the probabilistically-calculated ICR-Related Values[5] is a load reduction of 1% from implementation of 5% voltage reductions (it was previously 1.5%). Also starting in 2019, the Equivalent Forced Outage Rate - Demand ("EFORd") will be used in the modeling of peaking generation resources in the Transmission Security Analysis ("TSA") (previously, a 20% deterministic adjustment factor was used as the outage rate for peaking generating resources in the TSA). The Tariff changes that effected the modifications to these two assumptions were filed with the Commission on November 15, 2018.[6] The Commission accepted the Tariff changes on January 8, 2019,[7] with an effective date of January 14, 2019. In addition, this year, there are improvements in the long-term forecast methodology, which are described in the Black Testimony.[8] The rest of the methodology used to calculate the ICR-Related Values is the same Commission-approved methodology that was used to calculate the values submitted and accepted for preceding FCAs.

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[4] Pursuant to Section III.12.7.4 of the Tariff, load and capacity relief expected from system-wide implementation of certain actions specified in ISO New England Operating Procedure No. 4 – Action During a Capacity Deficiency ("OP-4") must be included in the calculation of the probabilistic ICR-Related Values. Voltage reduction is one of the actions of OP-4.

[5] The ICR, Local Resource Adequacy Requirement ("LRA") (which is an input in the LSR), MCL, MRI values and HQICCs are probabilistically calculated.

[6] *ISO New England Inc.*, Filing of Updates to Assumptions Used in the Installed Capacity Requirement and Related Values, Docket No. ER19-343-000, (filed Nov. 15, 2018).

[7] *ISO New England Inc.*, Docket No. ER19-343-000 (Jan. 8, 2019) (delegated letter order).

[8] By design, the load forecast methodology is not contained in the Tariff. Accordingly, Tariff changes are not needed to effect the improvements in the load forecast methodology. *See ISO New England Inc.*, 154 FERC ¶ 61,008 (2016); *order on reh'g*, 155 FERC ¶ 61,145 (2016).

II. INSTALLED CAPACITY REQUIREMENT

A. DESCRIPTION OF THE INSTALLED CAPACITY REQUIREMENT

Q: WHAT IS THE "INSTALLED CAPACITY REQUIREMENT?"

A: The ICR is the minimum level of capacity required to meet the reliability requirements 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 ICR 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 ICR 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 ICR.

The development of the ICR is consistent with the NPCC Full Member Resource Adequacy Criterion (Resource Adequacy Requirement R4),[9] under which the ISO must probabilistically evaluate resource adequacy to demonstrate that the loss of load

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[9] *See Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System* available at: https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf

expectation ("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 ICR-RELATED VALUES.

A: The ISO established the ICR-Related Values in accordance with the calculation methodology prescribed in Section III.12 of the Tariff. The ICR-Related Values and the assumptions used to develop them were discussed with stakeholders. The stakeholder process consisted of discussions with the NEPOOL Load Forecast Committee, PSPC and Reliability Committee. These committees' review and comment on the ISO's development of load and resource assumptions and the ISO's calculation of the ICR-Related Values were followed by advisory votes from the NEPOOL Reliability Committee and Participants Committee. State regulators also had the opportunity to review and comment on the ICR-Related Values as part of their participation on the PSPC, Reliability Committee, and Participants Committee. On October 4, 2019, the Participants Committee voted in support of the HQICCs both with and without Mystic 8 & 9. Both votes passed by a show of hands (with oppositions and abstentions recorded). Pursuant to Section 11.4 of the Participants Agreement, the Participants Committee also took advisory votes on the rest of the proposed ICR-Related Values calculated with and without Mystic 8 & 9 (*i.e.* the ICR, LSR for the SENE Capacity Zone, MCLs for the

Maine and NNE Capacity Zones, and MRI Demand Curves). The motion to support the values with Mystic 8 & 9 failed to meet the 60% required for a recommendation of support with 59.97% in favor. The motion to support the values without Mystic 8 & 9 also failed to meet the 60% required for a recommendation of support with 59.66% in favor. The ISO is filing with the Commission the ICR-Related Values to be used in FCA 14, which is associated with the 2023-2024 Capacity Commitment Period (as we already mentioned above, only the set of values that reflects Mystic 8 & 9's decision on whether to continue to operate in the 2023-2024 Capacity Commitment Period will be used in FCA 14).

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 that reports to the Reliability Committee. The PSPC is chaired by the ISO and its members are representatives of the NEPOOL Participants. The ISO engages the PSPC to assist with the review of key inputs used in the development of resource adequacy-based requirements such as ICRs, LSRs, MCLs and MRI Demand Curves, including appropriate assumptions relating to load, resources, and tie benefits for modeling the expected system conditions. Representatives of the six New England States' public utilities regulatory commissions are also invited to attend and participate in the PSPC meetings and several were present for the meetings at which the ICR-Related Values for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, were discussed and considered.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE CALCULATED BY THE ISO FOR FCA 14, WHICH IS ASSOCIATED WITH THE 2023-2024 CAPACITY COMMITMENT PERIOD.

A: The ICR value for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, is 33,431 MW.

Q: IS THIS THE AMOUNT OF INSTALLED CAPACITY REQUIREMENT THAT WAS USED FOR THE DEVELOPMENT OF THE SYSTEM-WIDE CAPACITY DEMAND CURVE?

A: No. The System-Wide Capacity Demand Curve was developed based on the net ICR of 32,490 MW, which is the 33,431 MW of ICR minus 941 MW of HQICCs (which are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of the Tariff).

B. DEVELOPMENT OF THE INSTALLED CAPACITY REQUIREMENT

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

A: The ICR was established using the General Electric Multi-Area Reliability Simulation ("GE MARS") model. GE MARS uses a sequential Monte Carlo simulation to compute the resource adequacy of a power system. This Monte Carlo process repeatedly simulates the year (multiple replications) to evaluate the impacts of a wide range of possible combinations of resource capacity and load levels taking into account random resource outages, load forecast uncertainty, and behind-the-meter photovoltaic (BTM PV) output uncertainty. For the ICR, the system is considered to be a one bus model, in that the New England transmission system is assumed to have no internal transmission constraints in this simulation. For each hour, the program computes the isolated area capacity available to meet demand based on the expected maintenance and forced outages of the resources and the expected demand. Based on the available capacity, the program determines the probability of loss of load for the system for each hour of the year. After simulating all hours of the year, the program sums the probability of loss of load for each hour to arrive at an annual probability of loss of load value. This value is tested for convergence, which is set to be 5% of the standard deviation of the average of the hourly loss of load values. If the simulation has not converged, it proceeds to another replication of the study year.

Once the program has computed an annual reliability index, if the system is less reliable than the resource-adequacy criterion (*i.e.*, the LOLE is greater than 0.1 days per year), additional resources are needed to meet the criterion. Under the condition where New England is forecasted to be less reliable than the resource adequacy criterion, proxy resources are used within the model to meet this additional need. The methodology calls for adding proxy units until the New England LOLE is less than 0.1 days per year. For the ICR-Related Values for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, the ISO did not need to use proxy units because there is adequate qualified capacity to meet the 0.1 days/year LOLE criterion.

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

Q: WHAT ARE THE MAIN ASSUMPTIONS UPON WHICH THE ICR-RELATED VALUES FOR FCA 14 ARE BASED?

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

1. LOAD FORECAST

Q: PLEASE EXPLAIN HOW THE ISO DERIVES THE LOAD FORECAST ASSUMPTION USED IN DEVELOPING THE INSTALLED CAPACITY REQUIREMENT AND RELATED VALUES.

A: For probabilistic-based calculations associated with ICR-Related Values, the ISO develops a forecasted distribution of typical daily peak loads for each week of the year based on 25 years of historical weather data and an econometrically estimated monthly model of typical daily peak loads. Each weekly distribution of typical daily peak loads includes the full range of daily peaks that could occur over the full range of weather experienced in that week and their associated probabilities. The 50/50 and the 90/10 peak loads are points on this distribution and used as reference points. The probabilistic-based calculations take into account all possible forecast load levels for the year. From these weekly peak load forecast distributions, a set of seasonal load forecast uncertainty multipliers are developed and applied to a specific historical hourly load profile to provide seasonal load information about the probability of loads being higher, and lower, than the peak load found in the historical profile. These multipliers are developed for New England in its entirety or for each subarea using the historic 2002 load profile.[10] For deterministic analyses such as the Transmission Security Analysis ("TSA"), the ISO uses the reference 90/10 load forecast, as published in the 2019-2028 Forecast Report of

[10] The year 2002 is used for the load profile since it has an adequate number of peak load days for the calculation of ICR and related values and it is the year NPCC uses for resource adequacy studies.

Capacity, Energy, Loads, and Transmission ("2019 CELT Report"), which is net of BTM PV resources.

Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN CAPACITY ZONES FOR FCA 14, WHICH IS ASSOCIATED WITH THE 2023-2024 CAPACITY COMMITMENT PERIOD.

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

The forecasted load for the Maine Capacity Zone was developed using the load forecast for the state of Maine.

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

Q: WHAT IS CURRENTLY PROJECTED TO BE THE NEW ENGLAND AND CAPACITY ZONE 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE 2023-2024 CAPACITY COMMITMENT PERIOD?

A: The following table shows the 50/50 and 90/10 peak load forecast for the 2023-2024 Capacity Commitment Period based on the 2019 load forecast as documented in the 2019

CELT Report. These values are reported as the "Reference – with Reduction for BTM PV" load forecast.

Table 2 – 50/50 and 90/10 Peak Load Forecast (MW)

	50/50	**90/10**
New England	28,838	30,851
SENE	12,540	13,571
Maine	2,117	2,222
NNE	5,430	5,690

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

A: 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: WHAT METHODOLOGY DID THE ISO USE TO REFLECT THE CONTRIBUTIONS OF BTM PV TO REDUCE THE LOAD FORECAST FOR FCA 14?

A: For FCA 14, as was done for prior FCAs, the ISO used 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 8,760 hours of the year. This reflects the actual impact of BTM PV installations in reducing system load, and uncertainty associated with the BTM PV.

Q: PLEASE ENNUMERATE THE UPDATES MADE TO THE LOAD FORECAST IN 2019 THAT HAD AN IMPACT ON THE INSTALLED CAPACITY REQUIREMENT.

A: As explained in the Black Testimony, improvements to the load forecast that impact the ICR-Related Values made in 2019 include: (1) a second weather variable, cooling degree days ("CDD") was incorporated in the model specification in addition to weighted temperature-humidity index ("WTHI"); (2) for monthly peak demand modeling, separate July and August monthly models were developed; and (3) the historical weather period used to generate probabilistic forecast was shortened from 40 years to 25 years. In addition, the daily peak load and weather for the historical period covering 2004-2018 was used as the model estimation period (2003-2017 was used the previous year). This is a standard update to the forecast cycle that is done every year.

Q: WHAT ARE THE ESTIMATED IMPACTS OF THE UPDATES TO THE LOAD FORECAST ON THE INSTALLED CAPACITY REQUIREMENT?

A: The impact of the three improvements to the long-term forecast methodology listed above and the change in the historical period used in the model estimation, which are all explained in the Black Testimony, had the following estimated impacts in the ICR:

		Estimated Impacts on net ICR (MW)
Updates to Gross Load Forecast for CCP 2023-2024	Forecast Cycle Case	-300
	Second Weather Variable Case	-855
	Separate July and August Peak Load Model Case	+45
	Shorter History Weather Period Case	-140
	All Updates Together	**-1,250**

Q: HOW WERE THE ESTIMATED IMPACTS OF THE UPDATES TO THE LOAD FORECAST IN THE INSTALLED CAPACITY REQUIREMENT DERIVED?

A: The estimated impacts of the updates to the 2019 long-term forecast on the net ICR were derived thru simulations using preliminary load forecast data prior to finalizing the 2019 CELT forecast. While the loads used are very close to the 2019 CELT forecast, they are not exactly the same. The simulations were done earlier in the process to provide stakeholders with the estimated impacts of the improvements to the long-term forecast methodology and the change in the historical period used in the model estimation.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA USED TO DEVELOP THE ICR-RELATED VALUES FOR FCA 14, WHICH IS ASSOCIATED WITH THE 2023-2024 CAPACITY COMMITMENT PERIOD.

A: The ICR-Related Values for FCA 14 were developed based on the Existing Qualified Capacity Resources for the 2023-2024 Capacity Commitment Period. This assumption is based on the latest available data at the time of the ICR-Related Values calculation.

Q: WHAT ARE THE RESOURCE CAPACITY VALUES FOR THE 2023-2024 CAPACITY COMMITMENT PERIOD?

A: The following tables illustrate the make-up of the 34,637 MW of capacity resources assumed in the calculation of the ICR-Related Values.

Table 3– Qualified Existing Non-Intermittent Generating Capacity Resources by Load Zone (MW)[11, 12]

Load Zone	Summer
CONNECTICUT	9,825.076
MAINE	2,874.064
NEW HAMPSHIRE	4,105.260
NEMA/BOSTON	2,702.047
RHODE ISLAND	1,826.126
SEMA	4,445.137
VERMONT	198.016
WESTERN/CENTRAL MASSACHUSETTS	3,812.334
Total New England	29,788.062

[11] Values reflect the existing resources with Qualified Capacity for FCA 14 at the time of the ICR calculation and reflect applicable retirements and terminations.

[12] Without Mystic 8 & 9, the NEMA/Boston and the Total New England capacity is 1,413 MW lower.

Table 4– Qualified Existing Intermittent Power Resources by Load Zone (MW)[13]

Load Zone	Summer	Winter
CONNECTICUT	104.931	105.983
MAINE	260.541	331.584
NEW HAMPSHIRE	112.334	190.476
NEMA/BOSTON	48.991	43.266
RHODE ISLAND	42.300	40.602
SEMA	162.667	160.885
VERMONT	71.574	115.722
WESTERN/CENTRAL MASSACHUSETTS	103.869	97.337
Total New England	907.207	1,085.855

Table 5– Qualified Existing Import Capacity Resources (MW)

Import Resource	Summer	External Interface
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total	82.800	

Table 6– Qualified Existing Demand Resources by Load Zone (Summer MW)

Load Zone	On-Peak	Seasonal Peak	Active Demand Capacity Resource	Total
CONNECTICUT	148.266	575.582	189.261	913.109
MAINE	192.035	0.000	139.535	331.570
NEW HAMPSHIRE	130.434	0.000	46.320	176.754
NEMA/BOSTON	764.388	0.000	95.715	860.103
RHODE ISLAND	284.335	0.000	47.581	331.916
SEMA	436.750	0.000	51.202	487.952
VERMONT	116.852	0.000	52.664	169.516

[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.

WESTERN/CENTRAL MASSACHUSETTS	456.121	26.618	105.641	588.380
Total New England	2,529.181	602.200	727.919	3,859.300

Although capacity resource data are tabulated above under the eight settlement Load Zones, only SENE (the combined SEMA, NEMA/Boston, and Rhode Island Load Zones), Maine (the Maine Load Zone) and NNE (the combined New Hampshire, Vermont and Maine Load Zones.) are relevant for FCA 14.

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

A: Resource additions, beyond those classified as "Existing Capacity Resources," and attritions (with the exception of those associated with permanent de-list bids, unconditional retirements and retirements below the Forward Capacity Auction Starting Price of $13.099 $/kW-month) are not assumed in the calculation of the ICR-Related Values for FCA 14, which is associated with the 2023-2024 Capacity Commitment Period, because there is no certainty that new resource additions or resource attritions below the Forward Capacity Auction Starting Price will clear the auction.

3. RESOURCE AVAILABILITY

Q: PLEASE EXPLAIN THE RESOURCE AVAILABILITY ASSUMPTIONS UNDERLYING THE CALCULATIONS OF THE ICR-RELATED VALUES FOR FCA 14, WHICH IS ASSOCIATED WITH THE 2023-2024 CAPACITY COMMITMENT PERIOD.

A: Resources are modeled at their Qualified Capacity values along with their associated resource availability in the calculation of the ICR-Related Values. For generating resources, scheduled maintenance assumptions are based on each unit's historical five-year average of scheduled maintenance. If the individual resource has not been operational for a total of five years, then NERC class average data is used to substitute for the missing annual data. In the ICR-Related Values model, it is assumed that maintenance outages of generating resources will not be scheduled during the peak load season of June through August.

An individual generating resource's forced outage assumption is based on the resource's five-year historical data from the ISO's database of NERC Generator Availability Database System ("GADS"). If the individual resource has not been operational for a total of five years, then NERC class average data is used to substitute for the missing annual data. The same resource availability assumptions are used in all the calculations except for the TSA, which requires the modeling of the availability of peaking generating resources with a deterministic adjustment factor.[14]

The Qualified Capacity of an Intermittent Power Resource is based on the resource's historical median output during the Reliability Hours averaged over a period of five years. The Reliability Hours are specific, defined hours during the summer and the winter, and hours during the year in which the ISO has declared a system-wide or a Load Zone-specific shortage event. Because this method already takes into account the

[14] *See* Section III.B of this testimony.

resource's availability, Intermittent Power Resources are assumed to be 100% available in the models at their "Qualified Capacity" and not based on "nameplate" ratings. Qualified Capacity is the amount of capacity that either a generating, demand, or import resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the FCM qualification process.

Performance of Demand Resources in the Active Demand Capacity Resource category is measured by actual response during performance audits and Operating Procedure No. 4 events that occurred in the summer and winter of the most recent five-year period, currently 2014 through 2018. To calculate historical availability, the verified commercial capacity of each resource is compared to its monthly net Capacity Supply Obligation. Demand Resources in the On-Peak Demand and Seasonal Peak Demand categories are non-dispatchable resources that reduce load across pre-defined hours, typically by means of energy efficiency. These types of Demand Resources are assumed to be 100% available.

4. OTHER ASSUMPTIONS

Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR FCA 14.

A: The assumed N-1 and N-1-1 transmission import transfer capability of the Southeast New England interface used to calculate the SENE Capacity Zone LSR and N-1 transmission export transfer capabilities of the Maine-New Hampshire interface used to calculate the Maine Capacity Zone MCL and the North-South interface used to calculate the NNE Capacity Zone MCL are shown in the table below.

Table 7 – Internal Interface Transfer Capabilities (MW)

Interface	Contingency	2023-2024
Southeast New England Import (for SENE LSR)	N-1	5,700
	N-1-1	4,600
Maine-New Hampshire (for Maine MCL)	N-1	1,900
North-South (for NNE MCL)	N-1	2,725

Q: PLEASE DISCUSS THE ISO'S ASSUMPTIONS REGARDING THE ACTIONS OF OPERATING PROCEDURE NO. 4 IN DEVELOPING THE ICR-RELATED VALUES FOR FCA 14.

A: In the development of the ICR, Local Resource Adequacy Requirement ("LRA"), MCL and MRI Demand Curves, assumed emergency assistance (*i.e.* tie benefits, which are described below) available from neighboring Control Areas, and 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 or actual capacity shortage conditions. Starting in 2019, the amount of load relief assumed obtainable from invoking 5% voltage reductions pursuant to Section III.12.7.4 (a) is 1%. Using the 1% reduction in system load demand, the assumed voltage reduction load relief values, which offset against the ICR, are 270 MW for June through September 2023 and 206 MW for October 2023 through May 2024.

5. TIE BENEFITS

Q: WHAT ARE TIE BENEFITS?

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

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

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

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

A: Internal transmission transfer capability constraints that are not addressed by either a LSR or MCL are modeled in the tie benefits study. The results of the tie benefits study are used as an input in the ICR, LRA, MCL, and MRI Demand Curves calculations.

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

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

Areas are conducting their planning, maintenance scheduling, unit commitment or real-time operations with a goal of maintaining their emergency assistance at a level needed to maintain the reliability of the New England system.

Q: PLEASE DESCRIBE THE TIE BENEFITS ASSUMPTIONS UNDERLYING THE ICR-RELATED VALUES FOR FCA 14.

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

Pursuant to Section III.12.9 of the Tariff, the ICR calculations for FCA 14 assume total tie benefits of 1,940 MW based on the results of the tie benefits study for the 2023-2024 Capacity Commitment Period. A breakdown of this total value is as follows: 941 MW from Quebec over the Hydro-Quebec Phase I/II HVDC Transmission Facilities, 136 MW from Quebec over the Highgate interconnection, 501 MW from New Brunswick (Maritimes) over the New Brunswick interconnections, and 362 MW from New York over the AC interconnections. Tie benefits are assumed not available over the Cross Sound Cable because the import capability of the Cross Sound Cable was determined to be 0.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR FCA 14 THE SAME AS THE METHODOLOGY USED FOR FCA 13?

A: Yes. The methodology for calculating the tie benefits used in the ICR for FCA 14 is the same methodology used to calculate the tie benefits used in the ICR for FCA 13. This methodology is described in detail in Section III.12.9 of the Tariff.

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

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

Q: PLEASE EXPLAIN THE ISO'S METHODOLOGY FOR DETERMINING THE TIE BENEFITS FOR FCA 14.

A: The tie benefits study for FCA 14 was conducted using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Control Areas of New Brunswick, New York, and Quebec. All of these Control Areas were assumed to be "at criterion," which means that the capacity of all three neighboring Control Areas was adjusted so that they would each have a LOLE of once in ten years when interconnected to each other.

The "at criterion" approach was applied to represent the expected amounts of capacity in each Control Area since each of these areas has structured its planning processes and markets (where applicable) to achieve the "at criterion" level of reliability. The total tie benefits to New England from New Brunswick (Maritimes), New York and Quebec were calculated first. To calculate total tie benefits, the interconnected system of New England and its directly interconnected neighboring Control Areas were brought to 0.1 days per year LOLE and then compared to the LOLE of the isolated New England system. Total tie benefits equal the amount of firm capacity equivalents that must be added to the isolated New England Control Area to bring New England to 0.1 days per year LOLE.

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

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

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

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

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

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

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

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

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

A: The following table lists the external transmission interconnections and the transfer capability of each used for calculating tie benefits for FCA 14:

Table 8 – Transmission Transfer Import Capability of the New England External Transmission Interconnections (MW)

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

One factor in the calculation of tie benefits is the transfer capability into New England of the interconnections for which tie benefits are calculated. In the first half of 2019, the transfer limits of these external interconnections were reviewed based on the latest available information regarding forecasted topology and load forecast information, and it was determined that no changes to the established external interface transmission import limits were warranted. The other factor is the transfer capability of the internal transmission interfaces. For internal transmission interfaces, when calculating tie benefits for the 2023-2024 ICR filed herewith, the ISO used the transfer capability values from its most recent transfer capability analyses.

6. AMOUNT OF SYSTEM RESERVE

Q: WHAT AMOUNT OF SYSTEM RESERVES IS REQUIRED TO BE INCLUDED AS AN ASSUMPTION IN THE DETERMINATION OF THE ICR?

A: Section III.12.7.4(c) of the Tariff requires that the determination of the ICR and related values include an amount of system reserves that is consistent with those needed for reliable system operations during emergency conditions.

Q: WHAT AMOUNT OF SYSTEM RESERVES DID THE ISO USE IN THE DETERMINATION OF THE PROBABILISTIC ICR-RELATED VALUES?

A: The ISO used 700 MW as the amount of system reserve in the determination of the probabilistic ICR-Related Values, which is the same as the value it used for FCA 13.

III. LOCAL SOURCING REQUIREMENT AND MAXIMUM CAPACITY LIMIT

A. DESCRIPTION OF LOCAL SOURCING REQUIREMENT

Q: WHAT IS THE LOCAL SOURCING REQUIREMENT?

A: The LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone. The LSR 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 LRA or (ii) the TSA Requirement. The LSR is applied to import-constrained Capacity Zones within New England.

Q: WHAT ARE IMPORT-CONSTRAINED CAPACITY ZONES?

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

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

A: A separate import-constrained Capacity Zone is identified in the most recent annual assessment of transmission transfer capability pursuant to ISO Open Access Transmission Tariff ("OATT"), Section II, Attachment K, as a zone for which the second contingency transmission capability results in a line-line TSA Requirement, calculated pursuant to Section III.12.2.1.2 of the Tariff and pursuant to ISO New England Planning Procedures, that is greater than the Existing Qualified Capacity in the zone, with the largest generating station in the zone modeled as out-of-service. Each assessment will model as out-of-service all retirement requests (including any received for the current Forward Capacity Auction at the time of this calculation) and Permanent De-List Bids as well as rejected for reliability Static and Dynamic De-List Bids from the most recent previous Forward Capacity Auction.

Q: WHICH ZONES WILL BE MODELED AS IMPORT CONSTRAINED CAPACITY ZONES FOR FCA 14?

A: After applying the import-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 14, the SENE Capacity Zone, which consists of the combined

Load Zones of SEMA, NEMA/Boston, and Rhode Island, will be modeled as a separate import-constrained Capacity Zone.

B. DEVELOPMENT OF THE LOCAL SOURCING REQUIREMENT

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

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

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

A: For each import-constrained capacity zone, the LRA is determined by modeling the zone under study vis-à-vis the rest of New England. This, in effect, turns the modeling effort into a series of two-area reliability simulations. The reliability target of this analysis is a system-wide LOLE of 0.105 days per year when the transmission constraints between the two zones are included in the model. Because the LRA is the minimum amount of resources that must be located in a zone to meet the system-reliability requirements for a capacity zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study until the reliability threshold, or target LOLE of 0.105,[15] is achieved.

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

A: The TSA 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.[16] This review determines the requirement of the sub-area to meet its load through internal generation and import capacity and is performed via a series of discrete transmission load flow study scenarios. In performing the analysis, static transmission interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area load

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

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

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 two differences between the assumptions relied upon for the TSA Requirement and the assumptions relied upon for determining the LRA. The first difference relates to the load forecast assumption. Resource adequacy analyses (*i.e.*, the analysis performed in determining the ICR, LRA, MCL, and MRI Demand Curves) are performed using the full probability distribution of load variations due to weather uncertainty. For the purpose of performing the deterministic TSA, single discreet points on the probability distribution are used; in accordance with ISO New England Planning Procedure No. 10, the analysis is performed using the published net 90/10 peak load forecast, which is net of the BTM PV forecasted value. The 90/10 peak load forecast corresponds to a peak load that has a 10% probability of being exceeded based on weather variation.

The second difference relates to the reliance on Operating Procedure No. 4 actions, which are not traditionally relied upon in TSAs. Specifically, no load or capacity relief obtainable from implementing Operating Procedure No. 4 actions are included in the calculation of the TSA Requirement.

Q: PLEASE DESCRIBE THE LOCAL RESOURCE ADEQUACY REQUIREMENT, TRANSMISSION SECURITY ANALYSIS REQUIREMENT, AND LOCAL SOURCING REQUIREMENT FOR THE SENE IMPORT-CONSTRAINED CAPACITY ZONE FOR FCA 14.

A: For FCA 14, the LRA, TSA Requirement and the LSR for the SENE import-constrained Capacity Zone for FCA 14 Capacity Zones are as follows:

Table 9 – Import Capacity Zone Requirements for the 2023-2024 Capacity Commitment Period (MW)

Capacity Zone	TSA Requirement	LRA	LSR
SENE	9,757	9,525	9,757

IV. MAXIMUM CAPACITY LIMIT

Q: WHAT IS THE MAXIMUM CAPACITY LIMIT?

A: The MCL is the maximum amount of capacity that is electrically located in an export-constrained Capacity Zone used to meet the ICR.

Q: WHAT ARE EXPORT-CONSTRAINED CAPACITY ZONES?

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

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

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

Q: WHICH ZONES WILL BE MODELED AS EXPORT CONSTRAINED CAPACITY ZONES FOR FCA 14?

A: After applying the export-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 14, the Maine and NNE Capacity Zones will be modeled as separate Export Constrained Capacity Zones. The Maine Capacity Zone consists of the Maine Load Zone. The NNE Capacity Zone consists of the combined New Hampshire, Vermont and Maine Load Zones.

Q: WHAT ARE THE MAXIMUM CAPACITY LIMITS FOR THE EXPORT-CONSTRAINED CAPACITY ZONES FOR FCA 14 AND HOW WERE THEY CALCULATED?

A: The MCL for the NNE Capacity Zone for FCA 14 is 8,445 MW. The MCL for the Maine Capacity Zone is 4,020 MW. These values also reflect the tie benefits assumed available over the New Brunswick and Highgate interfaces. The MCLs were calculated using the methodology that is reflected in Section III.12.2.2 of the Tariff.

In order to determine the MCLs, the New England net ICR and the LRA 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 ICR is the total amount of resources that the region needs to meet the 0.1 days/year LOLE, and the LRA for the *Rest of New England* is the minimum amount of resources required for that area to satisfy its reliability criterion, the difference between the two is the maximum amount of resources that can be used within the export-constrained Capacity Zone to meet the 0.1 days/year LOLE.

V. HQICCs

Q: WHAT ARE HQICCs?

A: HQICCs are capacity credits that are allocated to the Interconnection Rights Holders, which are entities that pay for and, consequently, hold certain rights over the Hydro Quebec Phase I/II HVDC Transmission Facilities ("HQ Interconnection").[17] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff, the tie benefit value for the HQ Interconnection was established using the results of a probabilistic calculation of tie benefits with Quebec. The ISO calculates HQICCs, which are allocated to Interconnection Rights Holders in proportion to their individual rights over the HQ Interconnection, and must file the HQICC values established for each FCA.

Q: WHAT ARE THE HQICC VALUES FOR FCA 14, WHICH IS ASSOCIATED WITH THE 2023-2024 CAPACITY COMMITMENT PERIOD?

A: The HQICC values are 941 MW for every month of the 2023-2024 Capacity Commitment Period.

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

VI. MRI DEMAND CURVES

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR FCA 14.

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 Curves for Maine and NNE for FCA 14, 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" ("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,[18] in 10 MW increments, applying the same assumptions used in determining the ICR. These system EENS values are translated into MRI values by estimating how an incremental change in capacity impacts system reliability at various capacity levels, as measured by EENS. An MRI curve is developed from these values with capacity represented on the X-axis and the corresponding MRI values on the Y-axis.

[18] The GE MARS model is the same simulation system that is used to develop the ICR and other values that specify how much capacity is required for resource adequacy purposes from a system planning perspective. For the development of the MRI Demand Curves, the same 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.

MRI values at various capacity levels are also calculated for the SENE import-constrained Capacity Zone and the Maine and NNE export-constrained Capacity Zones using the same modeling assumptions and methodology as those used to determine the LRA and the MCLs 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 FCA 14 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").[19] In other words, the scaling factor is equal to the value that produces a system demand curve that specifies a price of Net CONE at the net ICR (ICR minus HQICCs).

[19] For FCA 14, Net CONE has been determined as $8.187/kW-month.

To satisfy this requirement, the demand curve scaling factor for FCA 14 was developed for the System-Wide Capacity Demand Curve, the Import-Constrained Capacity Zone Demand Curve for the SENE import-constrained Capacity Zone, and the Export-Constrained Capacity Zone Demand Curves for the Maine and NNE export-constrained Capacity Zones in accordance with Section III.13.2.2.4 of the Tariff. The demand curve scaling factor is set at the value such that, at the quantity specified by the System-Wide Capacity Demand Curve at a price of Net CONE, the LOLE is 0.1 days per year.

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

A: For import-constrained Capacity Zones, the LRA and TSA Requirement values both play a role in defining the MRI-based demand curves as they do in setting the LSR. Under III.12.2.1.3 of the Tariff, prior to each FCA, the ISO must determine the MRI value of various capacity levels, for each import-constrained Capacity Zone. For purposes of these calculations, the ISO applies the same modeling assumptions and methodology used to determine the LRA 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 TSA Requirement minus the LRA, and; (ii) zero. By using a transfer capability that accounts for both the TSA and the LRAs, the ISO applies the same "higher of" logic used in the LSR to the derivation of sloped zonal demand curves. For FCA 14, the only import-constrained Capacity Zone is SENE and, therefore, there is only one Import-Constrained Capacity Zone Demand Curve.

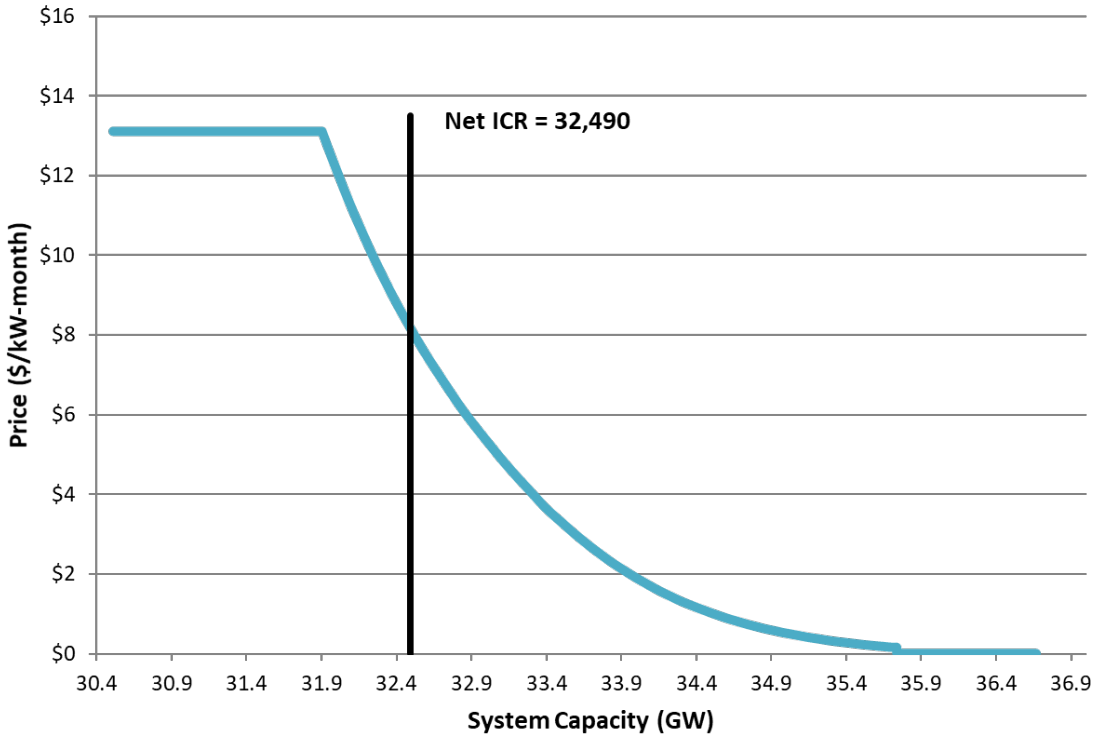
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVES FOR THE MAINE AND NNE CAPACITY ZONES.

A: Under Section III.12.2.2.1 of the Tariff, prior to each FCA, Export-Constrained Capacity Zone Demand Curves are calculated using the same modeling assumptions and methodology used to determine the export-constrained Capacity Zones' MCLs. 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 FCA 14, the export-constrained Capacity Zones are NNE and Maine, and, therefore, there are two Export-Constrained Capacity Zone Demand Curves.

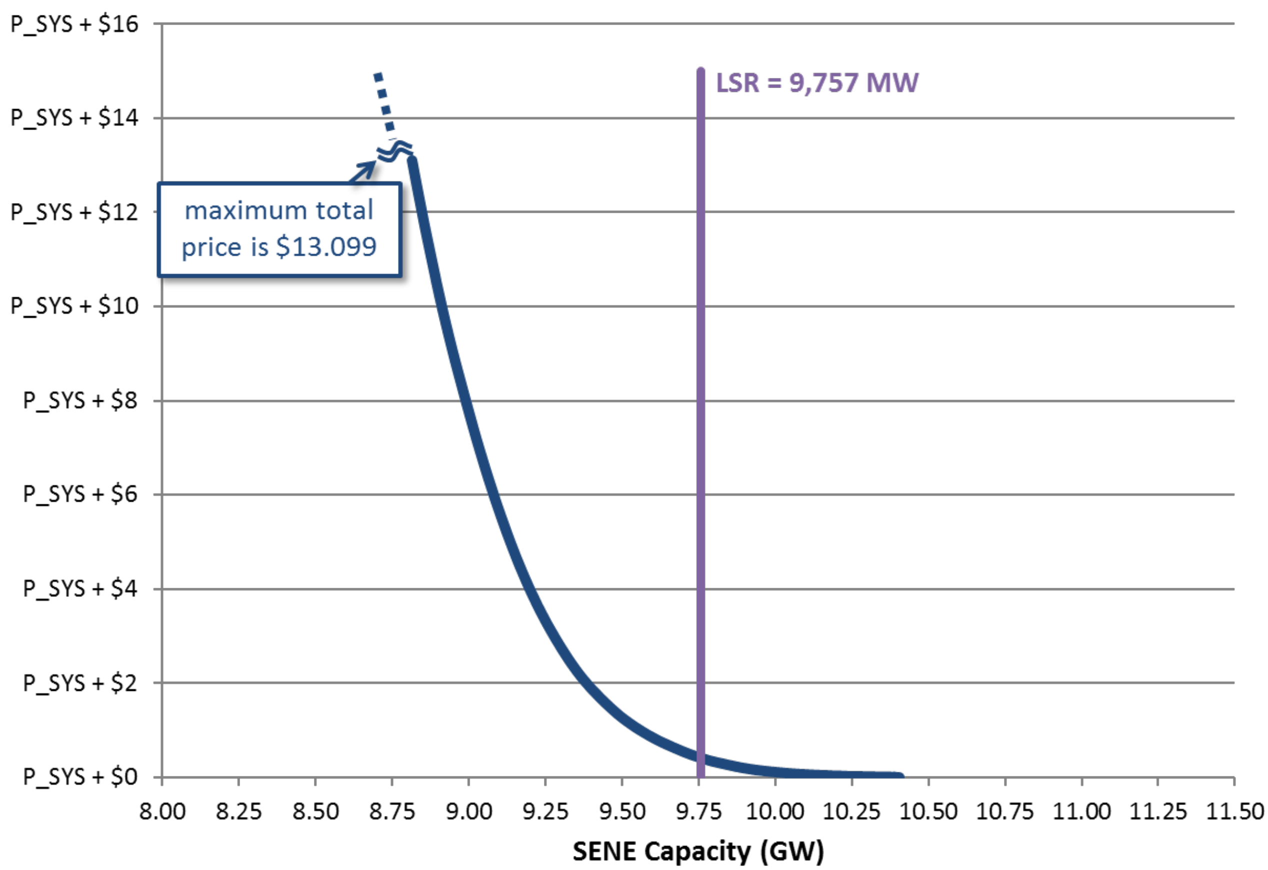
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR FCA 14?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI Demand Curves for FCA 14:

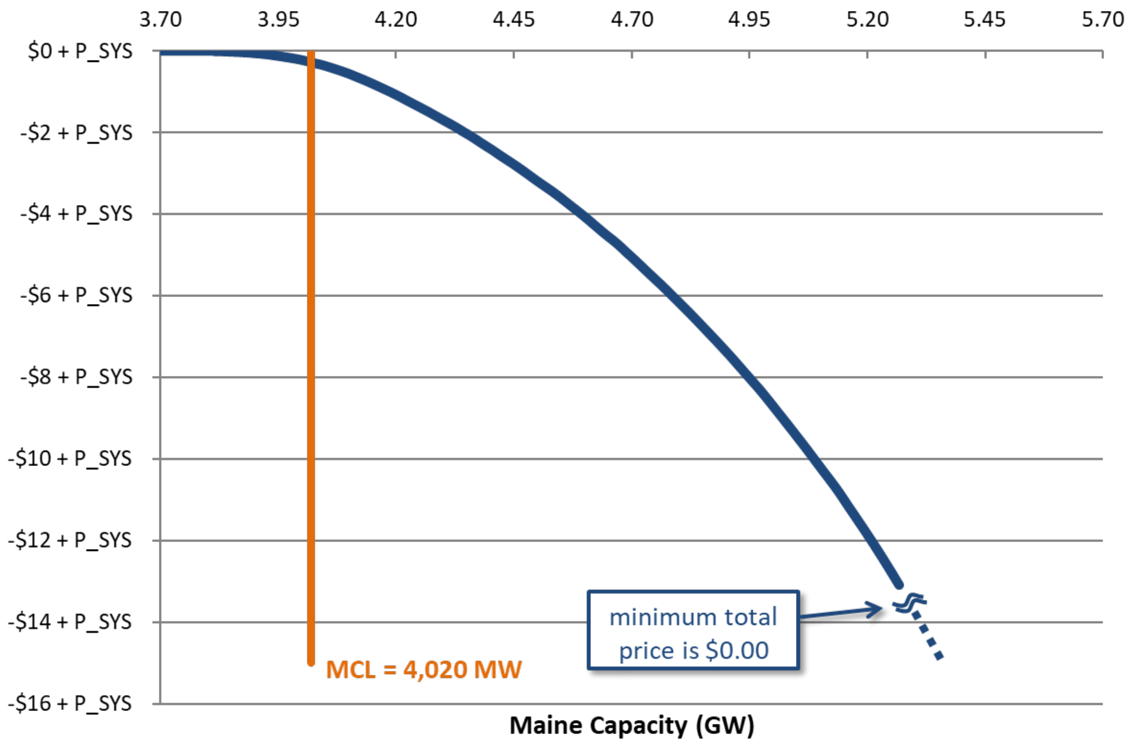
1. System-Wide Capacity Demand Curve for FCA 14



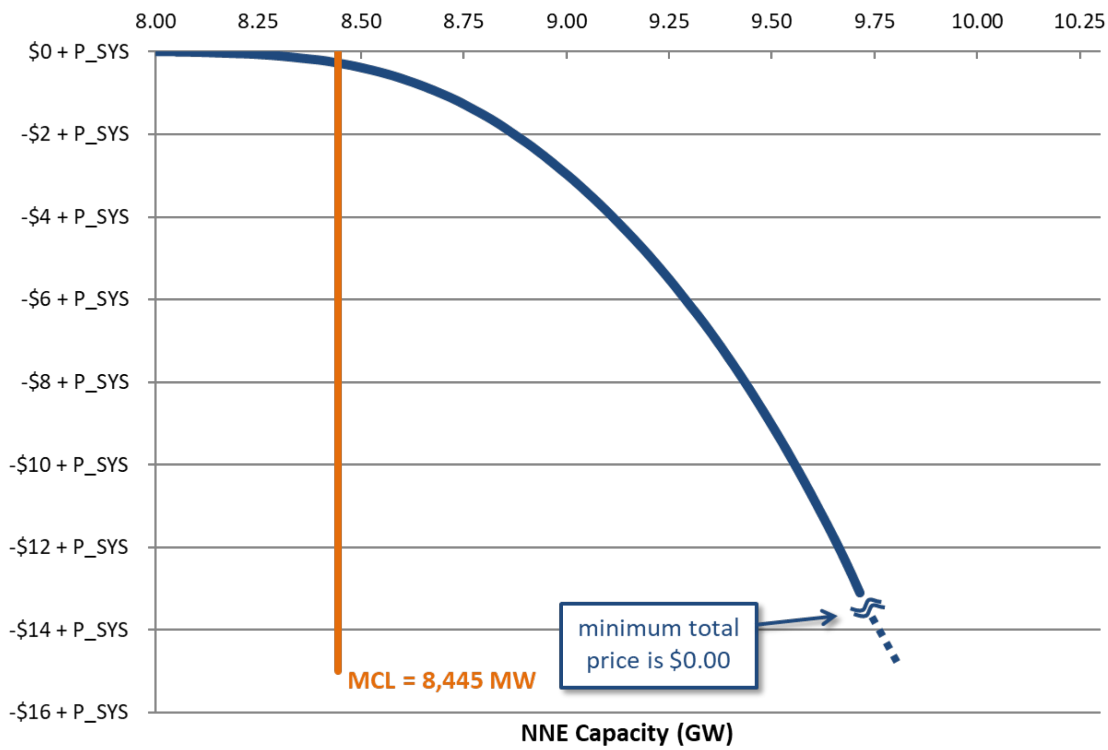
2. Import-Constrained Capacity Zone Demand Curve for the SENE Capacity Zone for FCA 14



3. Export-Constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 14



4. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 14



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/5/2019

Carissa Sedlacek

Executed on 11/5/2019

Peter Wong

Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.	**)**	**Docket No. ER20-___-000**

PREPARED TESTIMONY OF
JONATHAN BLACK
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: My name is Jonathan Black. I am employed by ISO New England Inc. (the "ISO") as the Manager of Load Forecasting in System Planning. My business address is One Sullivan Road, Holyoke, Massachusetts 01040.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: I joined the ISO in 2010 and have been the Manager of Load Forecasting for the past four years. In my current capacity, I am primarily responsible for the annual development of the long-term load, energy efficiency, and solar photovoltaic forecasts, as well as providing technical modeling support for short-term (*i.e.*, next seven day) load forecasting. As part of this role, my group applies a variety of data science, machine learning, and statistical techniques to perform predictive modeling and ongoing analytics for the growing number of factors that impact electricity consumption in New England. This work includes research on and modeling of emerging technologies and trends, as well as developing novel data processes to enable such modeling. Prior to joining the

ISO, I spent seven years working as an environmental scientist for Pioneer Environmental, Inc., where I managed hazardous waste site assessment and remediation projects. I have a B.S. in Civil and Environmental Engineering and an M.S. in Mechanical Engineering, both from the University of Massachusetts at Amherst. I am currently pursuing my Doctorate in the interdisciplinary Infrastructure and Environmental Systems program at the University of North Carolina in Charlotte, where I am researching advanced load forecasting techniques.

Q: WHAT ARE THE PURPOSES OF YOUR TESTIMONY?

A: The purposes of my testimony are: (1) to provide an overview of the methodology that the ISO uses to determine load forecasts and develop peak load assumptions reflected in the Installed Capacity Requirement ("ICR") and related values; (2) to explain the improvements made in 2019 to the long-term load forecast, which was published in the Forecast Report of Capacity, Energy, Loads, and Transmission ("CELT"),[1] and the reasons for those improvements; (3) to explain the update to the load forecast case cycle; and (4) to describe the process for updating the CELT in 2019.

II. TESTIMONY

A. OVERVIEW OF THE LOAD FORECAST METHODOLOGY

[1] The 2019 CELT was published on April 30, 2019.

Q: WHAT IS THE LONG-TERM LOAD FORECAST?

A: The ISO's long-term load forecast is a 10-year projection of gross and net load for states and the New England region. It includes annual gross and net energy, as well as seasonal gross and net peak demand (50/50 and 90/10). The gross peak demand forecast is probabilistic in nature. Weekly load forecast distributions are developed for each year of the forecast horizon. Annual 50/50 and 90/10 seasonal peak values are based on calculated percentiles for the peak week in the appropriate month (*i.e.*, July for summer, and January for winter).

Q: WHY DOES THE ISO DEVELOP THE LONG-TERM LOAD FORECAST?

A: Pursuant to Section III.12.8 of the Tariff, the ISO is required to forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecast must be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs, and assumptions must be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies.

Q: WHAT IS THE LONG-TERM LOAD FORECAST USED FOR?

A: The long-term load forecast is used in: (1) determining New England's resource adequacy requirements for future years; (2) evaluating reliability and economic performance of the electric power system under various conditions; (3) planning-needed transmission improvements; and (4) coordinating maintenance and outages of generation and transmission infrastructure assets.

Q: WHAT DATA SOURCES DOES THE ISO USE IN DEVELOPING THE LONG-TERM LOAD FORECAST FOR THE NEW ENGLAND REGION?

A: In developing the long-term load forecast, the ISO utilizes the data sources included in the table below to develop estimates of historical and forecast gross load. Note that price-responsive demand ("PRD"), energy efficiency ("EE"), behind-the-meter photovoltaic ("BTM PV"), and passive distributed generation are all added back (*i.e.*, they are "reconstituted") to historical net load to develop historical gross load used in forecast modeling. Reconstitution is performed at the hourly level, and the sum of hourly gross loads over a longer time interval (*e.g.*, a month) yields the gross energy for that period.

Data Series	Source(s)
Economic data	Moody's Analytics
Weather	Vendor supplied
Historical electricity prices	Department of Energy (DOE)/Energy Information Administration (EIA)
Load	ISO internal database (settlements data)
BTM PV	Based on a combination of internal, distribution owner, and vendor data
EE performance	ISO EE measures database (internal)
PRD	ISO internal database (settlements data)
Passive distributed generation	ISO internal database (settlements data)

Q: PLEASE DESCRIBE, AT A HIGH LEVEL, HOW THE ISO DEVELOPS THE LONG-TERM LOAD FORECAST FOR THE NEW ENGLAND REGION.

A: Historical monthly gross energy and macroeconomic variables are used to estimate econometric monthly gross energy models, which in turn are used to forecast gross energy. Historical gross daily peak loads, weather, and gross monthly energy are used to estimate econometric monthly demand models, which in turn are used to forecast gross peak demand. Weekly weather distributions are input to the gross demand models to create a probabilistic demand forecast for each week of the forecast horizon. The 95th and 99th percentiles (*i.e.*, "P95" and "P99", respectively) of these weekly forecast distributions are then calculated, and the maximum weekly P95 and P99 of each month is used as the "50/50" and "90/10" gross demand forecasts for that month.[2]

Q: WHERE ARE THE DETAILS OF THE LOAD FORECAST METHODOLOGY LOCATED?

A: The details of the load forecast methodology are located in the load forecast webpage,[3] which includes: (1) the energy and demand modeling methodology, which is described in the Forecast Modeling Procedure (*e.g.* 2019 Forecast Modeling Procedure); (2) a forecast data spreadsheet (with worksheets), which includes all final forecast values; (3) the model details spreadsheet (*e.g.* 2019 energy & peak model details), which includes all resulting energy and peak models; and (4) ten year hourly forecasts in Edison Electric Institute format (*e.g.* hourly 2019 forecasts for the New England region, Regional System Plan subareas, and Standard Market Design Load Zones).

[2] More detailed information on the forecast methodology is available at: https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf

[3] https://www.iso-ne.com/system-planning/system-forecasting/load-forecast

B. IMPROVEMENTS MADE IN 2019 TO THE LONG-TERM LOAD FORECAST

Q: WHY DID THE ISO EVALUATE ITS PEAK DEMAND LOAD FORECAST MODEL THIS YEAR?

A: Summer peak loads in New England stem from extreme weather (characterized by consecutive hot, humid days) overlapping with workdays (*i.e.*, non-holiday weekdays). For this reason, conditions assumed in the ISO's long-term summer peak demand forecast are uncommon, and may not occur at all during some summer seasons. The ISO evaluated its peak demand load forecast model this year because, during the 2018 summer season, for the first time since summer 2013, New England experienced several non-holiday weekdays with peak-eliciting weather. Specifically, there were several periods of consecutive extreme weather days: July 1-6 (impacted by the July 4th holiday, which occurred on a Wednesday); August 5-7, and August 27-29.

Q: WHAT DID THE ISO'S ANALYSIS OF THE FORECAST PERFORMANCE FOR THE SUMMER OF 2018 REVEAL?

A: The analysis of the forecast performance for the summer of 2018 illustrated that the observed peak loads were lower than the CELT 2018 forecasts given the weather conditions, as shown in the table below. For example, the weather conditions on August 29, 2018, as measured by a three-day weighted temperature-humidity index ("WTHI") value of 82.0 degrees, were equivalent to the extremity of summer weather assumed for the CELT 2018 "90/10" forecast, which is associated with only a 10% probability of being exceeded in any summer period. As shown in the table below, the actual peak gross load on August 29th was 1,553 MW lower than the 90/10 CELT 2018 forecast. Given this new information, the ISO had reason to reevaluate its models and test them for performance issues during peak load conditions.

Peak Day*	Type	Day of Week	Gross Peak (MW)	Peak Hour (Gross Peak)	WTHI @ Gross Peak Hour
CELT2018 90/10	***Forecast***	-	***31,451***	-	***82.0***
CELT2018 50/50	***Forecast***	-	***29,060***	-	***79.9***
8/29/2018	Actual	Wed	29,898	15	82.0
8/28/2018	Actual	Tue	29,133	16	80.4
8/7/2018	Actual	Tue	28,952	15	80.9
8/6/2018	Actual	Mon	28,527	17	79.6
8/2/2018	Actual	Wed	27,874	15	78.1

Gross load is reconstituted for demand reductions associated with EE, BTM PV, and PRD. *Peak days during week of July 4th were removed due to holiday effects.

Q: HOW DID THE ISO ADDRESS THE FORECAST PERFORMANCE ISSUES?

A: To address the forecast performance issues, the ISO incorporated improvements to the summer demand load forecast models' specification that better capture the load response given a variety of weather, and especially during extreme weather. As fully described below, improvements were made in the gross energy modeling and in the gross demand modeling.

Q: PLEASE DESCRIBE THE IMPROVEMENTS MADE IN THE GROSS ENERGY MODELING AND THEIR IMPACT ON SUMMER DEMAND FORECASTS.

A: Under the changes to the gross energy modeling, separate monthly energy models were developed instead of annual models to better capture shifts in seasonal trends. This change had a negligible impact on summer demand forecasts.

Q: PLEASE ENNUMERATE THE IMPROVEMENTS MADE IN THE GROSS DEMAND MODELING METHODOLOGY.

A: The following three improvements were made in the summer gross demand modeling: (1) a second weather variable was incorporated in the model specification; (2) for monthly peak demand modeling, separate July and August monthly models were developed; and (3) the historical weather period used to generate the probabilistic forecast was shortened from 40 years to 25 years. In addition, one improvement was made in the winter gross demand modeling. Specifically, in the winter demand model specification, a second weather variable, heating degree days ("HDD") was incorporated, and the dry bulb temperature variable used in CELT 2018 was replaced with "effective temperature," which is a wind speed adjusted temperature.

Q: DID ALL THE IMPROVEMENTS YOU MENTIONED ABOVE HAVE AN IMPACT ON THE ICR?

A: No. The improvement in the winter demand model specification did not have an impact on the ICR. [4]

[4] The new winter demand model was presented to and discussed with the Load Forecast Committee ("LFC") and the Planning Advisory Committee ("PAC"). However, because the winter demand model does not have an impact on the ICR and related values, it was not presented to the Power Supply Planning Committee ("PSPC") or the Reliability Committee.

Q: PLEASE DESCRIBE THE SUMMER MODEL SPECIFICATION IMPROVEMENT AND THE REASONS FOR IT.

A: The model specification improvement consisted of incorporation of a second weather variable in addition to WTHI. Specifically, the additional weather variable of cooling degree days ("CDD") was incorporated in the model specification. This improvement was made to mitigate forecast performance issues identified during extreme weather conditions that took place during the summer of 2018. The new model specification results in significant improvements in forecast performance, especially during extreme weather (*i.e.*, peak load) conditions.

Q: PLEASE DESCRIBE HOW THE SUMMER MODEL SPECIFICATION IMPROVEMENT WAS VALIDATED AND THE RESULTS OF THE VALIDATION.

A: In order to validate the summer model specification improvement, a total of fifteen years of summer data were used. The evaluation included tests of both in-sample (i.e., how well the model fits the data used in its estimation) and out-of-sample (*i.e.*, how well the model performs on test data not used in model estimation) model performance.[5] For the first comparison, the CELT 2018 and CELT 2019 summer model specifications (*i.e.*, the specific variable forms) were trained on data during the period 2004-2018, and the in-sample performance was evaluated for that period using mean absolute percent error

[5] Results of forecast model performance validation and testing were presented at the July 25, 2019 Power Supply Planning Committee meeting and the September 10, 2019 Reliability Committee meeting. The presentations are available at, respectively, https://www.iso-ne.com/static-assets/documents/2019/07/20190725_a03_2019_longterm_forecasts_icr.pptx and https://www.iso-ne.com/static-assets/documents/2019/09/a2_supplemental_information_on_changes_in_the_celt_2019_summer_demad_forecast_presentation.pptx

("MAPE") and mean error ("ME") as metrics. MAPE is a measure of the magnitude of the errors irrespective of direction (*i.e.*, over/under), and ME is a measure of how much, on average, a model over-or under-forecasts, where positive ME indicates over-forecasting. The results of in-sample performance analysis are tabulated below.

IN-SAMPLE MODEL PERFORMANCE

Model	All Non-Holiday Weekdays (647 days)		Highest 10% Demand Days (65 days)		Highest 5% Demand Days (32 days)	
	MAPE	ME	MAPE	ME	MAPE	ME
CELT 2018	**2.6%**	**-99**	**2.5%**	**222**	**3.0%**	**570**
CELT 2019	2.2%	-104	1.5%	-3	1.5%	158

Both CELT models were then trained using data during the period 2003-2017, and the models were tested for out-of-sample performance during July/August of 2018. The results of the out-of-sample performance are tabulated below.

OUT-OF-SAMPLE MODEL PERFORMANCE

Model	All Non-Holiday Weekdays (42 days)		Highest 10 Demand Days		Highest 5 Demand Days	
	MAPE	ME	MAPE	ME	MAPE	ME
CELT 2018	**3.4%**	**217**	**4.0%**	**1,013**	**4.1%**	**1,184**
CELT 2019	2.2%	87	1.5%	355	1.2%	348

The ISO simulated the CELT 2011 forecast with the CELT 2018 and 2019 summer demand models, so that eight years of out-of-sample forecast performance could be evaluated (*i.e.*, 2011-2018).

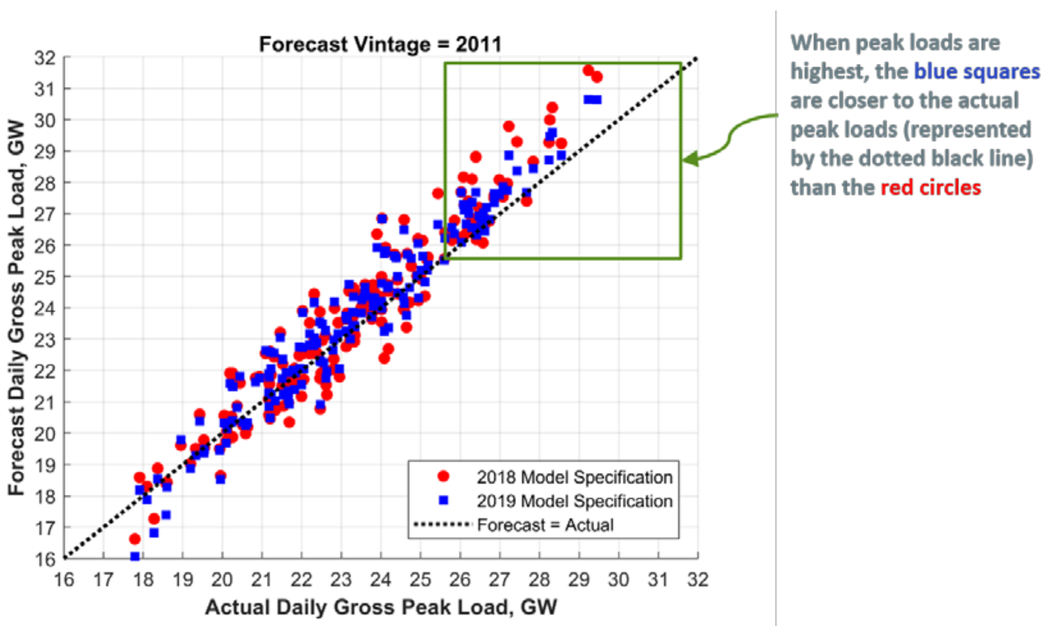
To test for out-of-sample performance, the period used for model estimation ended in 2010 for both the CELT 2018 and CELT 2019 models. Note that actual energy was an input to the demand models to remove the effects of recession-driven, macroeconomic forecast uncertainty and, thus, to isolate the performance of the demand models. A comparison of out-of-sample MAPE and ME during 2011-2018 summer days (July non-holiday weekdays) is tabulated below. Based on out-of-sample performance, the 2019 summer peak demand model performs much better than the 2018 model.

OUT-OF-SAMPLE MODEL PERFORMANCE

Model	All Non-Holiday Weekdays (169 days)		Highest 10% Demand Days (17 days)		Highest 5% Demand Days (9 days)	
	MAPE	ME	MAPE	ME	MAPE	ME
CELT 2018	3.4%	408	4.2%	1,130	5.0%	1,358
CELT 2019	2.9%	392	2.7%	759	2.9%	826

SCATTER PLOT OF OUT-OF SAMPLE MODEL PERFORMANCE

JULY NON-HOLIDAY WEEKDAYS, 2011-2018



In summary, results of both in-sample and out-of-sample performance testing using data spanning 15 summer seasons consistently validate that the model specification changes implemented in CELT 2019 result in an improved forecast, especially during peak load conditions.

Q: PLEASE EXPLAIN WHY SEPARATE JULY AND AUGUST MONTHLY MODELS WERE DEVELOPED TO IMPROVE MONTHLY PEAK LOAD DEMAND MODELING.

A: Given that forecasts of energy are one of the input variables within peak demand models, monthly demand models were developed to be consistent with the conversion to monthly energy modeling incorporated in CELT 2019.

Q: PLEASE EXPLAIN WHY THE HISTORICAL WEATHER PERIOD USED TO GENERATE THE PROBABILISTIC FORECAST WAS SHORTENED FROM 40 YEARS TO 25 YEARS.

A: The ISO uses historical weather to generate a weekly distribution of peak loads for the 10-year forecast horizon. The historical weather data is used to represent both the range and the associated likelihood of possible weather during each week of the year. For CELT 2019, the ISO shortened the weather history used to generate its probabilistic, weekly demand forecast from 40 to 25 years. The new 25-year period covers 1991 to 2015. This change was made primarily because wind speed data needed for the updated winter demand model used for CELT 2019 was not available for all of the years of the former 40-year period used (*i.e.*, 1975 to 2014). The 25-year period allows the ISO to keep a consistent historical weather period for both summer and winter monthly forecasts. Moreover, a survey of other ISO/RTO methodologies revealed that a shorter length of weather history used in demand modeling is more consistent with the length of weather history used by other North American ISOs/RTOs, as most of them use 25 or fewer years in their selection of weather history. Specifically, ERCOT uses 15 years, MISO uses 20 years, PJM uses 25 years, NYISO uses 20 years, and IESO uses 31 years.

Relative to the former 40-year historical weather period, the 25-year historical period used in CELT 2019 for the probabilistic demand forecast results in a slightly lower probability of extreme weather conditions (and thus extreme peak loads) throughout some weeks over the summer period.

C. UPDATE TO THE FORECAST CYCLE CASE

Q: IN ADDITION TO THE UPDATES THAT RESULTED FROM THE IMPROVEMENTS TO THE SUMMER GROSS DEMAND MODELING METHODOLOGY, WERE THERE ANY OTHER UPDATES MADE TO THE CELT 2019?

A: Yes. The daily peak load and weather for the historical period covering 2004-2018 was used as the model estimation period (2003-2017 was used the previous year). This is a standard update to the forecast cycle that is done every year.

Q: PLEASE DESCRIBE HOW THE UPDATE TO THE FORECAST CYCLE IS DONE.

A: Each year, the ISO updates the macroeconomic, load and weather data to develop its peak demand forecast. Since CELT 2016, the ISO has used 15 years of load and weather data to estimate peak demand forecast models. The result has been that, for each forecast cycle, the newly available year of data replaces the first year used in the previous forecast.

Q: WHAT HAS BEEN THE EFFECT OF THE YEARLY UPDATE TO THE FORECAST CYCLE?

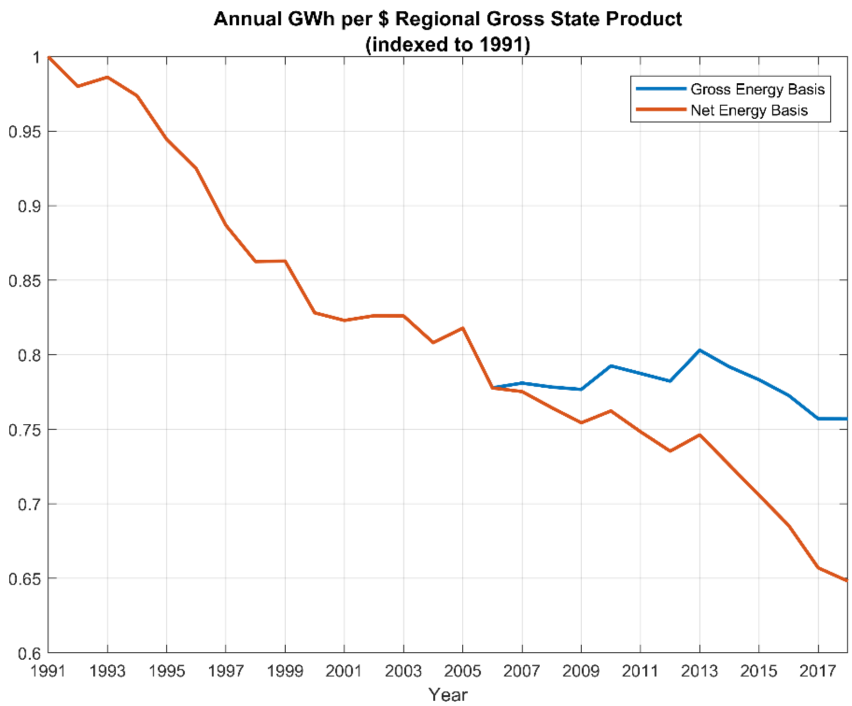
A: For the past few years, there has been a decrease in the summer demand forecast as data are updated for each successive forecast cycle.

Q: WHY HAS THE YEARLY UPDATE TO THE FORECAST CYCLE CAUSED A DECREASE IN THE SUMMER DEMAND FORECAST?

A: The decrease in the summer demand forecast attributable to updating the forecast cycle is a result of the decline in the overall electric energy intensity of the New England economy, which is in part due to the increase end-use efficiency improvements driven by federal standards. Specifically, a significant share of building end-use electricity consumption is subject to Department of Energy ("DOE") standards. Since 2005, 45 mandatory DOE efficiency standards have taken effect. Evolution of these standards drive out-of-market, end-use efficiency improvements. The resulting electricity savings occur after the implementation of standards as appliance stock turns over.

Q: WHAT ARE THE ELECTRIC ENERGY INTENSITY TRENDS OF THE NEW ENGLAND REGION'S ECONOMY?

A: The electric energy intensity of the New England region's economy has been declining for the past few decades. The following graph illustrates the long-term trend in the relationship between annual electric gigawatt-hours and regional gross state product (indexed to the year 1991 to show relative changes).



The brown line is based on net load energy. The blue line is based on gross load energy after reconstituting for the energy savings from EE, BTM PV, and PRD (note that historical energy savings from PRD are very small). Based on the difference between the blue and brown lines, the effects of market-facing EE and BTM PV have been responsible for most, but not all, of this decline in intensity since 2006.

Q: HOW ARE THE EFFECTS OF THE INCREASED END-USE EFFICIENCY IMPROVEMENT DRIVEN BY FEDERAL STANDARDS AND THE DECLINE IN THE ELECTRIC ENERGY INTENSITY OF THE NEW ENGLAND ECONOMY CAPTURED IN THE LOAD FORECAST MODEL?

A: Recent trends in regional electricity consumption such as the increase end-use efficiency improvement driven by federal standards and the decline in the electric energy intensity of the New England economy are captured as new data are added to the historical period used to estimate the ISO's econometric load forecast model and the earlier data rolls off. The decrease in the load forecast due to this standard data refresh has also been observed for the previous two CELT forecasts, as shown below.

50/50 Summer Peak Gross Forecast Comparison (MW) ***[Excerpt from 2018 Forecast Data, Tab 10G]***

	2018	2019	2020	2021	2022	2023	2024	2025	2026	CAGR (%)*
ISO-NE										
2018 CELT	29,060	29,298	29,504	29,744	29,994	30,245	30,486	30,721	30,957	0.8
2017 CELT	29,454	29,753	30,039	30,327	30,623	30,923	31,223	31,521	31,820	1.0
Difference	-394	-455	-535	-583	-629	-678	-737	-800	-863	

50/50 Summer Peak Gross Forecast Comparison (MW) ***[Excerpt from 2017 Forecast Data, Tab 10G]***

	2017	2018	2019	2020	2021	2022	2023	2024	2025	CAGR (%)*
ISO-NE										
2017 CELT	29,146	29,454	29,753	30,039	30,327	30,623	30,923	31,223	31,521	0.9
2016 CELT	29,307	29,652	29,975	30,276	30,578	30,883	31,190	31,493	31,794	0.9
Difference	-161	-198	-222	-237	-251	-260	-267	-270	-273	

*CAGR = Compound Annual Growth Rate

D. PROCESS FOR UPDATING THE CELT FOR 2019

Q: PLEASE EXPLAIN THE PROCESS THAT WAS FOLLOWED TO UPDATE THE CELT FOR 2019.

A: As is done each year, the ISO discussed its development of the CELT 2019 forecast with the LFC and the PAC. The discussions with the LFC took place at the LFC meetings on December 14, 2018, February 11, 2019, and March 29, 2019.[6] The ISO provided the PAC with updates on the development of the forecast at both its March 21, 2019 and April 25, 2019 meetings.[7] Relative to the development of ICR and related values, the forecast was also discussed at four PSPC meetings on July 25, 2019, August 9, 2019, August 26, 2019, and September 9, 2019.[8] The ISO further discussed the CELT 2019 forecast at the August 20, 2019 and September 10, 2019 Reliability Committee meetings.[9]

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[6] Materials associated with the LFC discussions are available at: http://www.iso-ne.com/committees/reliability/load-forecast/

[7] Materials associated with the PAC discussions are available at: https://www.iso-ne.com/static-assets/documents/2019/03/a4_draft_2019_isone_annual_energy_and_summer_peak_forecast.pdf (March 21, 2019) and https://www.iso-ne.com/static-assets/documents/2019/04/a4_final_2019_load_forecast_winter_peak_demand_and_subregional_forecast.pdf (April 25, 2019)

[8] Materials associated with the PSPC discussions are available at: https://www.iso-ne.com/static-assets/documents/2019/07/20190725_a03_2019_longterm_forecasts_icr.pptx (July 25, 2019); https://www.iso-ne.com/static-assets/documents/2019/08/20190809_pspc_icr_fca14_wawom89.pptx (August 10, 2019); https://www.iso-ne.com/static-assets/documents/2019/08/pspc_a03_icr_values_fca14_1.pptx (August 29, 2019) https://www.iso-ne.com/static-assets/documents/2019/09/pspc_a03_icr_values_fca14_excluding_mysticunits_final.pptx (September 9, 2019)

[9] Materials associated with the RC discussions are available at: https://www.iso-ne.com/static-assets/documents/2019/08/a11_tie_benefits_and_icr_fca14_presentation_rev1.pptx (August 20, 2019); https://www.iso-ne.com/static-assets/documents/2019/09/a2_supplemental_information_on_changes_in_the_celt_2019_summer_demad_forecast_presentation.pptx (September 10, 2019)

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Executed on 11/5/19

Jonathan Black

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