November 7, 2023

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. ER24-___-000, Filing of Installed Capacity Requirement, Hydro Quebec Interconnection Capability Credits and Related Values for Forward Capacity Auction 18 (Associated with the 2027-2028 Capacity Commitment Period)**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] ISO New England Inc. (the "ISO"), joined by the New England Power Pool Participants Committee ("NEPOOL"),[2] 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 2027-2028 Capacity Commitment Period,[3] which is associated with Forward Capacity Auction ("FCA") 18: (i) Installed Capacity Requirement ("ICR"),[4] (ii) Maximum Capacity Limits ("MCLs") for the Maine ("Maine") and Northern New England ("NNE") Capacity Zones,[5] (iii) Hydro Quebec Interconnection Capability Credits ("HQICCs"); and (iv) Marginal Reliability Impact ("MRI") Demand Curves.[6] The ICR, net ICR, the MCLs for the Maine and

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1 16 U.S.C. § 824d (2021).

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

3 The 2027-2028 Capacity Commitment Period starts on June 1, 2027 and ends on May 31, 2028.

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

5 The 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, and

NNE Capacity Zones, HQICCs, and MRI demand curves are collectively referred to herein as the "ICR-Related Values." [7]

The ISO is proposing the following ICR-Related Values for FCA 18:

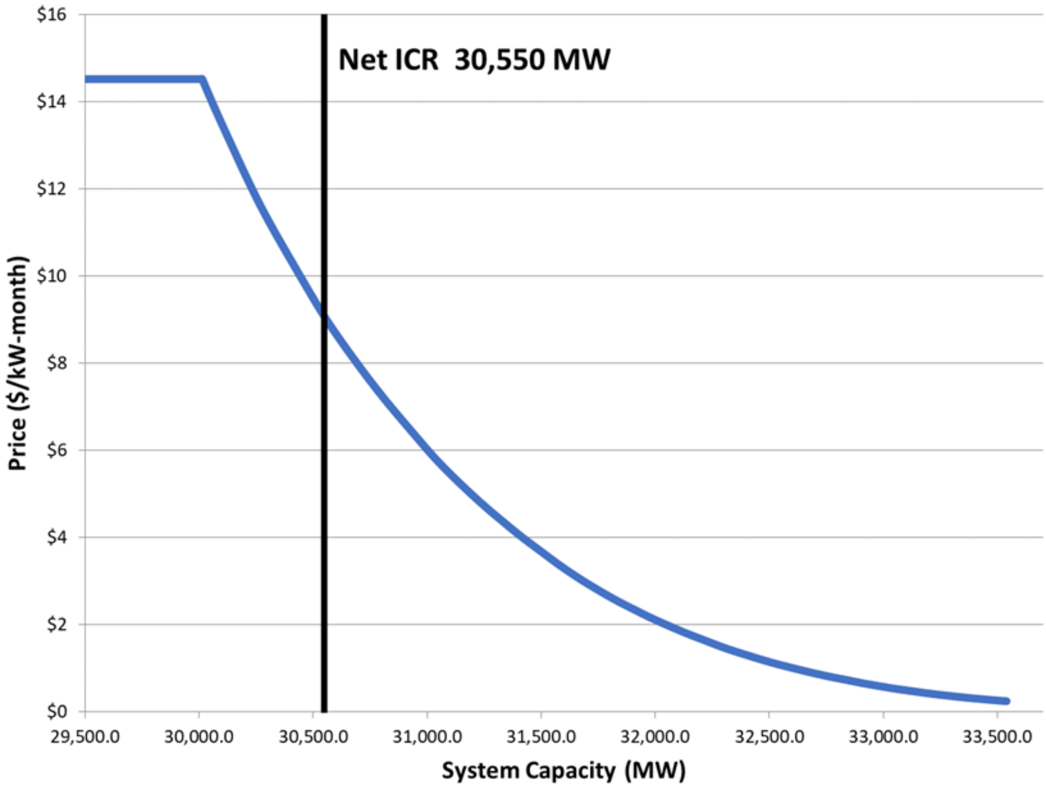
ICR	31,591 MW
Net ICR (ICR minus HQICCs)	30,550 MW
MCL for Maine	4,150 MW
MCL for NNE	8,760 MW
HQICCs	1,041 MW

Along with the following MRI Demand Curves:

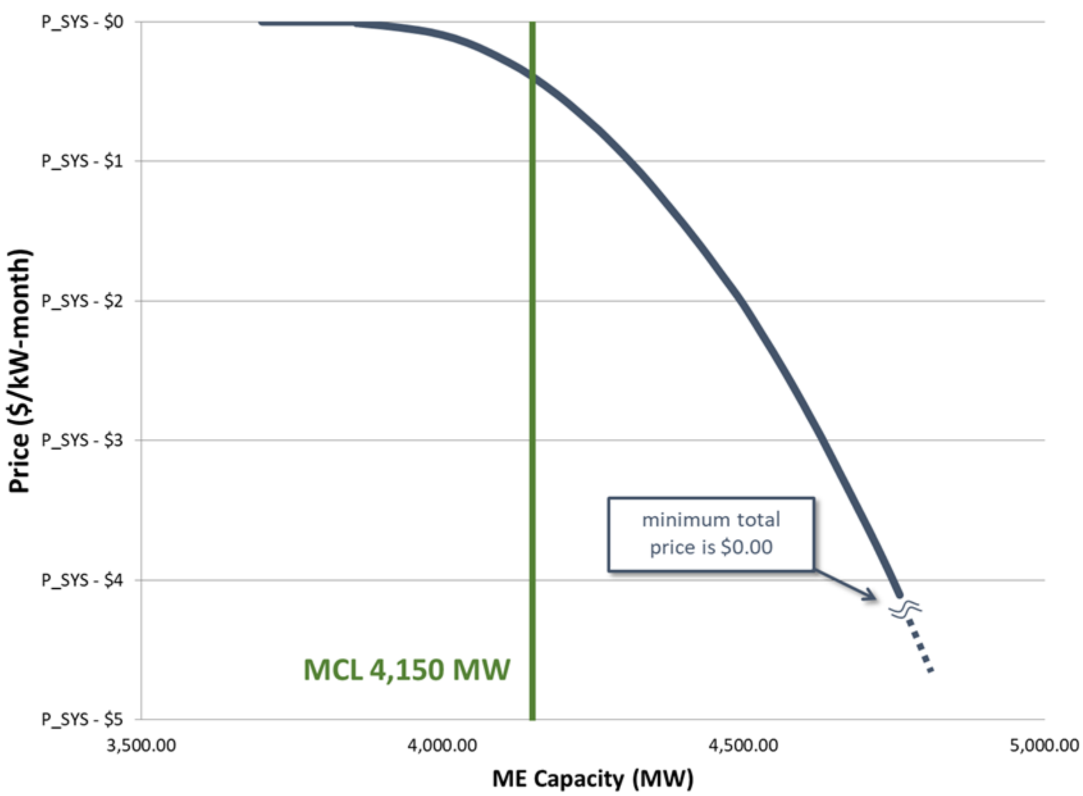
the export-constrained Capacity Zone Demand Curves for the Maine and NNE Capacity Zones.

[7] Pursuant to Section III.12.3 of the Tariff, the ICR must be filed 90 days prior to the applicable FCA. FCA 18, which is the primary FCA for the 2027-2028 Capacity Commitment Period, is scheduled to commence on February 5, 2024.

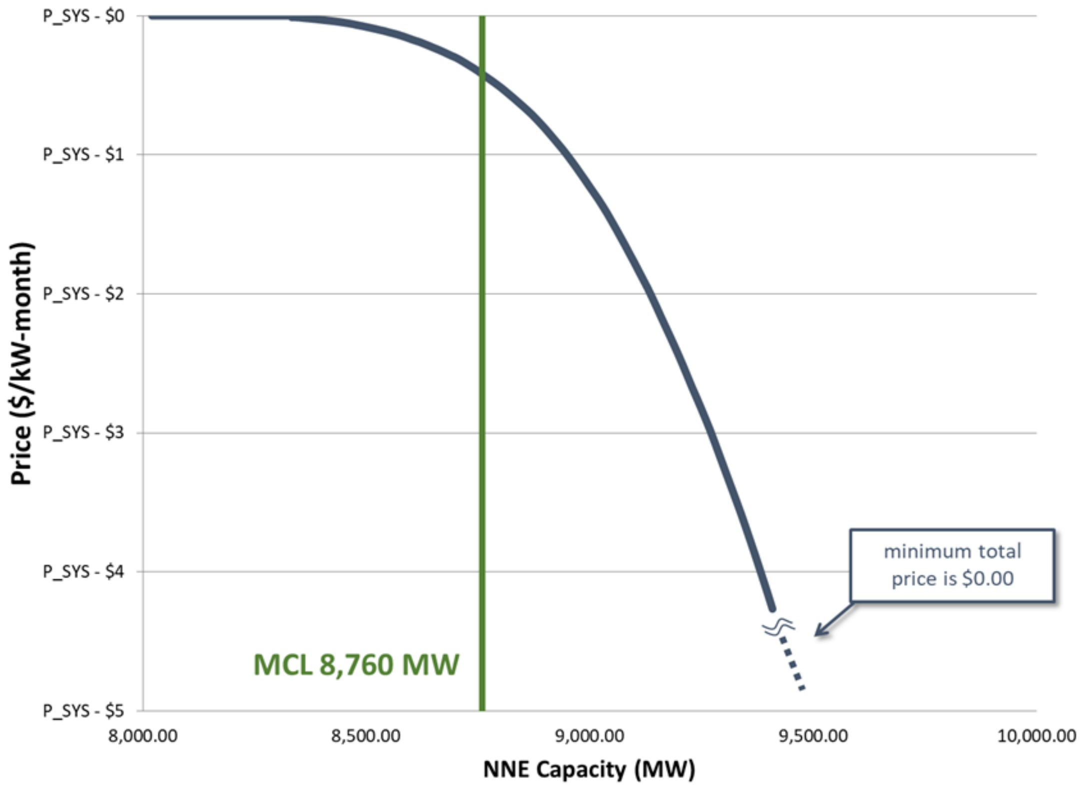
1. System-Wide Capacity Demand Curve for FCA 18



2. Export-Constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 18



3. Export-Constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 18



Pursuant to the Tariff, the ISO must also calculate Local Sourcing Requirements (LSRs) for identified import-constrained Capacity Zones.[8] An LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone to meet the ICR.[9] Specifically, the LSR is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy (LRA) or (ii) the Transmission Security Analysis (TSA) requirements. Similar to FCA 17, the import-constrained zone criterion testing that was conducted on the proposed Southeast New England ("SENE")[10]

[8] *See* Section III.12.4 of the Tariff.

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

[10] The proposed SENE import-constrained Capacity Zone includes the Southeast Massachusetts, Northeastern Massachusetts and Rhode Island Load Zones.

import-constrained Capacity Zone did not result in a need for the zone for FCA 18. Therefore, there are no import-constrained Capacity Zones for FCA 18[11] and, accordingly, the ISO did not have to calculate LSRs.

The derivation of the ICR-Related Values is discussed in Sections III-VI of this filing letter and in the attached Testimony of Manasa Kotha, the ISO's Supervisor, Capacity Requirement & Accreditation (the "Kotha Testimony"). The Kotha Testimony is solely sponsored by the ISO.

With the exception of the enhancements and updates to the methodologies used to develop the heating and transportation electrification forecasts (described in Section III.B.1.a of this filing letter and in the attached Testimony of Jonathan Black, the ISO's Manager, Load Forecasting, which is solely sponsored by the ISO), 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 the preceding FCA.[12] 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.[13] Accordingly, the Commission should accept the proposed values as just and reasonable without change to become effective on January 6, 2024.

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[11] *See* May 31, 2023 Zonal Modeling for FCA 18 presentation to the Power Supply Planning Committee, available at: https://www.iso-ne.com/static-assets/documents/2023/05/a05_05312023_pspc_fca18_zone_formation-aff3d9d5.pdf

[12] *ISO New England Inc.,* Docket No. ER23-405-000 (Nov. 8, 2022).

[13] *Id; see, also* FERC orders approving prior ICR filings: 2026-2027 ICR: *ISO New England Inc.,* Docket No. ER23-405-000 (Dec. 20, 2022) (delegated letter order); 2025-2026 ICR: *ISO New England Inc.,* Docket No. ER22-378-000 (Dec. 21, 2021) (delegated letter order); 2024-2025 ICR: *ISO New England Inc.,* Docket No. ER21-371-000 (Jan. 7, 2021) (delegated letter order), 2023-2024 ICR: *ISO New England Inc.,* Docket No. ER20-311-000 (Jan. 3, 2020); 2022-2023 ICR: *ISO New England Inc.,* Docket No. ER19-291-000 (Jan. 4, 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).

I. DESCRIPTION OF FILING PARTIES 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 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").

The signatories to the New England Power Pool Agreement, which was first entered into in 1971, are referred to collectively as "NEPOOL." Currently, there are more than 520 signatories, which are referred to either as "members" or "Participants." They include all of the electric utilities rendering or receiving services under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, demand response providers (including owners of distributed generation and aggregators of such generation), developers, end users, and a merchant transmission provider. Pursuant to revised governance provisions the Commission accepted in *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004), the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff." All correspondence and communications in this proceeding should be addressed to the undersigned for the ISO as follows:

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II. STANDARD OF REVIEW

The ISO submits the proposed ICR-Related Values for FCA 18, which is associated with the 2027-2028 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."[15] Under Section 205, the Commission "plays 'an essentially passive and reactive' role"[16] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[17] 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."[18] The ICR-Related Values submitted herein "need not be the only reasonable methodology, or even the most accurate."[19] 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.[20]

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

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

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

[17] *Id.* at 9.

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

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

[20] *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 a 31,591 MW ICR for FCA 18, which is associated with the 2027-2028 Capacity Commitment Period. This value reflects tie benefits (emergency energy assistance) assumed obtainable from Quebec, Maritimes (New Brunswick), and New York in the aggregate amount of 2,115 MW. However, the 31,591 MW ICR value does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 1,041 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 30,550 MW.[21]

B. Development of the ICR

With the exception of the updates and enhancements to the methodologies used to develop the heating and transportation electrification forecasts (described below and in the Black Testimony), the methodology used to develop the ICR-Related Values for FCA 18 is the same as that used to calculate the values for the previous FCA. 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 of 5% voltage reductions, and maintaining a minimum level of operating reserve. All modeling assumptions have been updated to reflect expected changes in system conditions. These updated assumptions are described below.

1. Load Forecast

The forecasted peak loads of the entire New England Control Area for the 2027-2028

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[21] The net ICR is used in the development of the MRI Demand Curves, which will be used to procure capacity in FCA 18.

Capacity Commitment Period are one major input into the calculation of the ICR-Related Values. For the purpose of calculating the ICR for FCA 18, which is associated with the 2027-2028 Capacity Commitment Period, the ISO used the load forecast published in the 2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission dated May 1, 2023 ("2023 CELT Report").[22] As in previous years, the load forecast methodology reflects economic and demographic assumptions as reviewed by the NEPOOL Load Forecast Committee ("LFC").[23]

The projected New England Control Area summer 50/50 peak load[24] for the 2027-2028 Capacity Commitment Period is 27,440 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.[25]

a. Updates to Heating and Transportation Electrification Forecasts

Since 2020, the ISO develops transportation electrification and heating electrification forecasts. At the time, the ISO recognized that both transportation electrification and heating electrification are expected to play a pivotal role in the achievement of economy-wide greenhouse gas reduction mandates and goals that the New England states have established. As such, both transportation electrification and the growth of heating electrification impact electric energy consumption in New England. The initial methodology for the development of the heating and transportation electrification forecasts is described in the Testimony of Jonathan Black, submitted as part of the ISO's filing of the ICR and related values for FCA 15.[26]

As explained in the Black Testimony, this year, the ISO updated the methodology to develop the heating electrification forecast. The most notable change to the methodology is that, this year, in addition to forecasting residential space heating (which was the only type of heating

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[22] Kotha Testimony at 10-12.

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

[24] 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 referenced value is the 2023 CELT "Net (with Reductions for BTM PV)" peak load forecast, as shown in CELT Section 1.1 Summer Peak Capabilities and Load Forecast.

[25] *See* Kotha Testimony at 10-11.

[26] *See* https://www.iso-ne.com/static-assets/documents/2020/11/icr_for_fca_15.pdf

included in prior heating electrification forecasts), the ISO forecasted commercial space heating as well as residential and commercial water heating. Another notable change included a comprehensive characterization of New England's existing building stock, which was subsequently used to inform all heat pump adoption forecasts, and associated energy and demand forecasts. Moreover, in order to complete the methodological enhancements, the ISO developed two other significant changes: (1) the ISO developed an array of "heating pathways" that specify a heat pump technology that could be used to either partially or fully electrify a given building's space or water heating needs; and (2) the ISO developed mathematical models that, for any given outdoor ambient temperature, predict the electric heating demand for every possible combination of building type and heating pathway. Based on this new methodology, the ISO updated its adoption forecast such that it aligns with the updated building and heating pathway accounting.[27]

As also explained in the Black Testimony, there are two updates to the transportation electrification forecast this year. First, as part of its annual revisiting of its state-level EV adoption forecasts, the ISO worked to develop a more consistent adoption forecasting framework that incorporated all federal, state, and local goals and mandates regarding EV adoption. Second, the ISO enhanced the modeling of weather sensitivity of the energy and demand impacts of personal light-duty vehicle EV charging. This aligned the methodology across all vehicle types, and moves from static monthly profiles to dynamic modeling of daily energy consumption based on weather.[28]

2. Resource Capacity Ratings

The ICR for FCA 18, which is associated with the 2027-2028 Capacity Commitment Period, is based on the latest available resource ratings[29] of Existing Capacity Resources that have qualified for FCA 18 at the time of the ICR calculation. These resources will be described in the qualification informational filing for FCA 18 that will be submitted to the Commission, pursuant to the revised schedule for FCA 18, on November 22, 2023.

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[27] Black Testimony at 5-7.

[28] *Id.* at 8.

[29] The resource capacity ratings for FCA 18, which is associated with the 2027-2028 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 seventeen FCAs conducted to date. *See* the 2015-2016 ICR Letter Order; the 2016-2017 ICR Letter Order; the 2017-2018 ICR Letter Order; the 2018-2019 ICR Letter Order; the 2019-2020 ICR Letter Order; the 2020-2021 ICR Letter Order; the 2021-2022 ICR Letter Order; the 2022-2023 ICR Letter Order; the 2023-2024 ICR Letter Order; the 2024-2025 ICR Letter Order; the 2025-2026 ICR Letter Order; and the 2026-2027 ICR Letter Order.

Resource additions and most resource attritions[30] are not assumed in the calculation of the ICR for FCA 18, 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 adjustments to remove surplus capacity from the system, discussed in the Kotha Testimony, are designed to address these resource addition and attrition uncertainties.[31]

3. Resource Availability

The proposed ICR value for FCA 18, which is associated with the 2027-2028 Capacity Commitment Period, reflects generating resource availability assumptions based on historical scheduled maintenance and forced outages of these capacity resources.[32] For generating resources, individual unit scheduled maintenance assumptions are based on each unit's most recent five-year historical average of scheduled maintenance. Each 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 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.

4. Other Assumptions

a. Tie Benefits

New England's Commission-approved method for establishing the ICR requires that

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[30] 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.

[31] Kotha Testimony at 8-9.

[32] The assumed resource availability ratings for FCA18, which is associated with the 2027-2028 Capacity Commitment Period, are discussed in the Kotha 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 seventeen FCAs. *See* note 13, *supra.*

assumptions be made regarding the tie benefits value to be used as an input in the calculation.[33] 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 0.1 days/year LOLE criterion reduces the ICR and lowers the amount of capacity to be procured in the FCA.

The ISO's proposed ICR for FCA 18 reflects tie benefits calculated from the Quebec, Maritimes (New Brunswick), and New York Control Areas.[34] 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 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. The procedures associated with the tie benefits calculation methodology were also addressed in detail in the transmittal letter for the 2014-2015 ICR Filing.[35] The total tie benefits assumption and a breakdown of this value by Control Area are as follows:

Control Area	Tie Line	Tie Benefits (MW)
Quebec	HQ Phase I/II HVDC	1,041

[33] *See* Section III.12.9 of the Tariff. The methodology for calculating tie benefits to be used in the Installed Capacity Requirement for FCA 18 is the same methodology used to calculate the tie benefits used in the ICR for Capacity Commitment Periods associated with prior FCAs.

[34] *See* 2014-2015 ICR Filing, Karl-Wong Testimony at 27, for an explanation of the methodology employed by the ISO in determining tie benefits for the 2014-2015 Capacity Commitment Period, which the ISO also used 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, the 2022-2023 Capacity Commitment Period, the 2023-2024 Capacity Commitment Period, the 2024-2025 Capacity Commitment Period, the 2025-2026 Capacity Commitment Period, and the 2026-2027 Capacity Commitment Period.

[35] *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).

Quebec	Highgate	136
Maritimes (New Brunswick)	New Brunswick	544
New York	NY AC Ties	394
New York	Cross Sound Cable	0
		Total = 2,115

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 2023, the ISO reviewed the transfer limits of these external interconnections based on the latest available information regarding forecasted topology and load forecast information, and 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	External Interface Import Capability (MW)	Forced Outage Rate (%)	Maintenance (Weeks)
HQ Phase I/II HVDC	1,400	2.5	1.8
Highgate	200	0.2	0.7
New Brunswick	700	0.7	2.1
NY AC Ties	1,400	0.4	6.1
Cross Sound Cable	0	0.8	7.8
	Total = 3,700	**N/A**	**N/A**

The other factor is the transfer capability of the internal transmission interfaces. In calculating tie benefits for the ICR for FCA 18, for internal transmission interfaces, the ISO used the transfer capability values from its most recent transfer capability analyses.

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 minimum 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 18.

IV. MAXIMUM CAPACITY LIMITS

In the FCM, the ISO must also calculate MCLs.[36] An MCL is the maximum amount of capacity that can be located in an export-constrained Capacity Zone to meet the ICR.[37] The general purpose 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.

As Ms. Kotha explains, in the determination of the MCL for an export-constrained Capacity Zone, a Local Resource Adequacy Requirement (which is the minimum amount of resources required for an area to satisfy its reliability criterion) is used to identify the minimum amount of resources required for the Rest of New England.[38]

For FCA 18, which is associated with the 2027-2028 Capacity Commitment Period, the ISO has determined that there are two export-constrained Capacity Zones of Maine and Northern New England (NNE). Therefore, the ISO calculated the following MCLs for the Maine and NNE Capacity Zones using the methodology reflected in Section III.12.2.2 of the Tariff:

Export-Constrained Capacity Zone	MCL (MW)
Maine	4,150
NNE	8,760

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").[39] Pursuant to Sections III.12.9.5 and III.12.9.7 of the Tariff,

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

[37] *Id.*

[38] *See* Kotha Testimony at 30-31 (explaining the methodology for calculating the LRA for the Rest of New England).

[39] *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

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 18 is 1,041 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 a System-Wide Capacity Demand Curve and Capacity Zone Demand Curves to be used in FCA 18.

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 Demand Curve pursuant to Section III.13.2.2.1 of the Tariff.[40] Below is the System-Wide Capacity Demand Curve for FCA 18.

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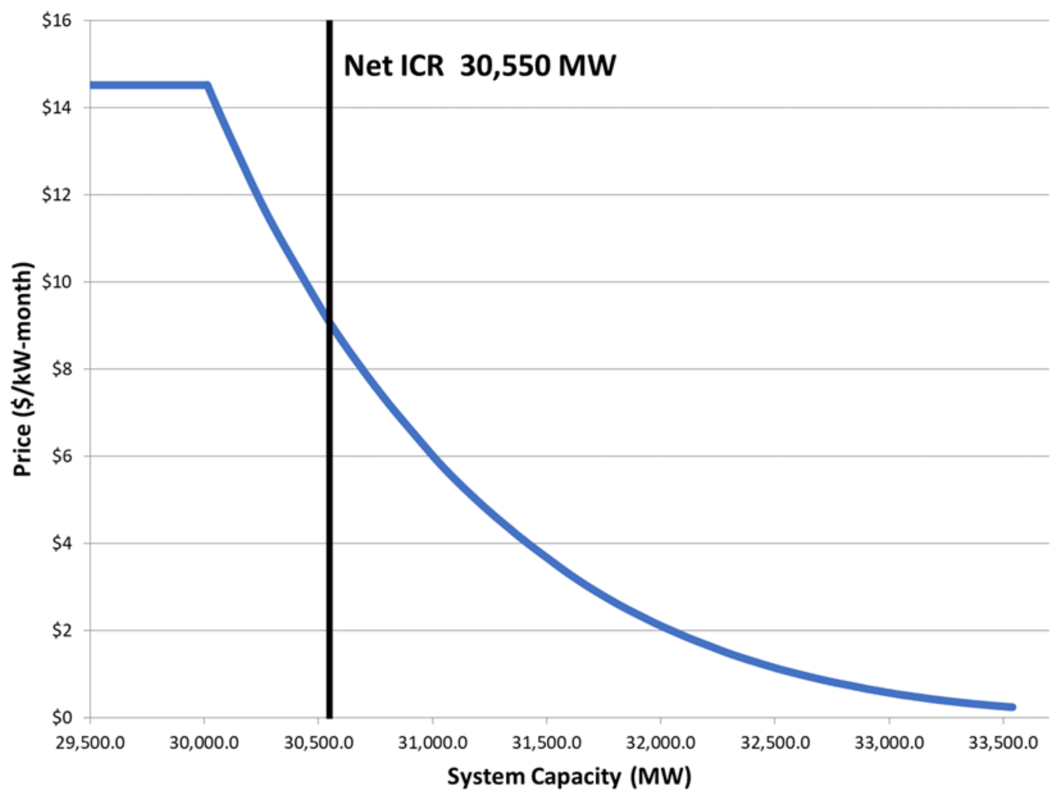
by that IRH and such costs are not included in the calculation of the Regional Network Service rate."). *See also* Section III.12.9.7 of the Tariff ("[t]he tie benefits from the Quebec Control Area over the HQ Phase I/II HVDC-TF calculated in accordance with Section III.12.9.1 shall be allocated to the 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.").

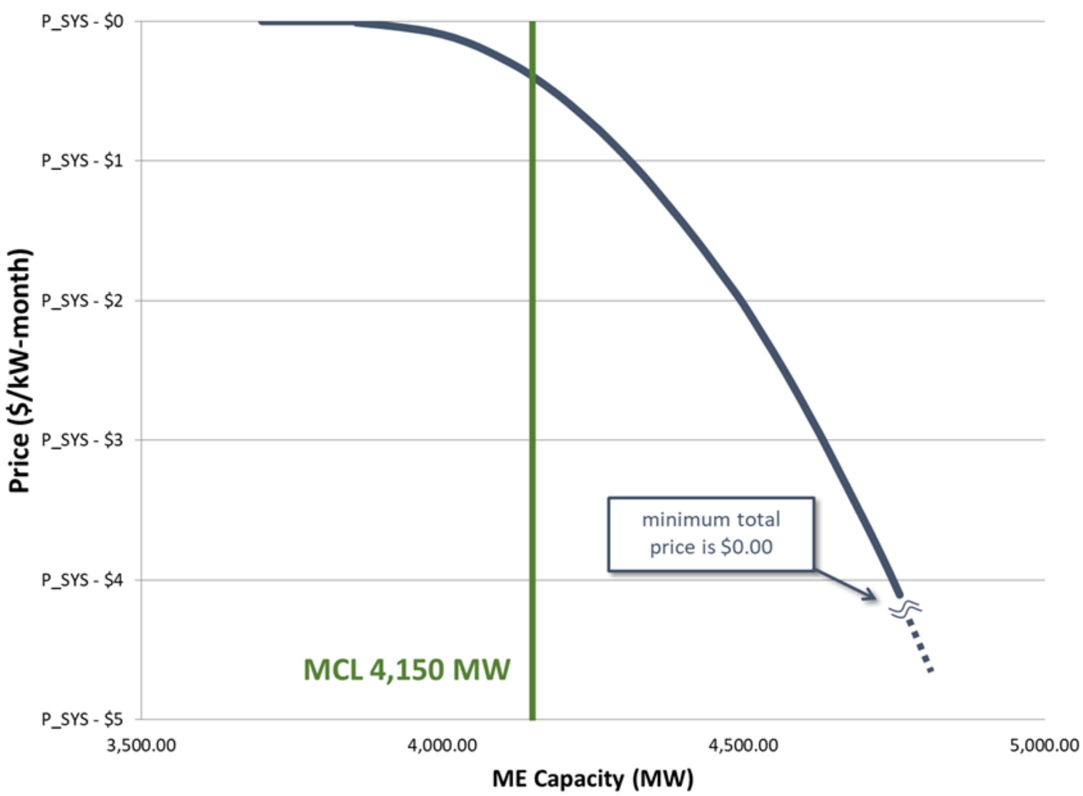
[40] Additional details regarding the calculation of the System-Wide Capacity Demand Curve are included in the Kotha Testimony at 33-34.



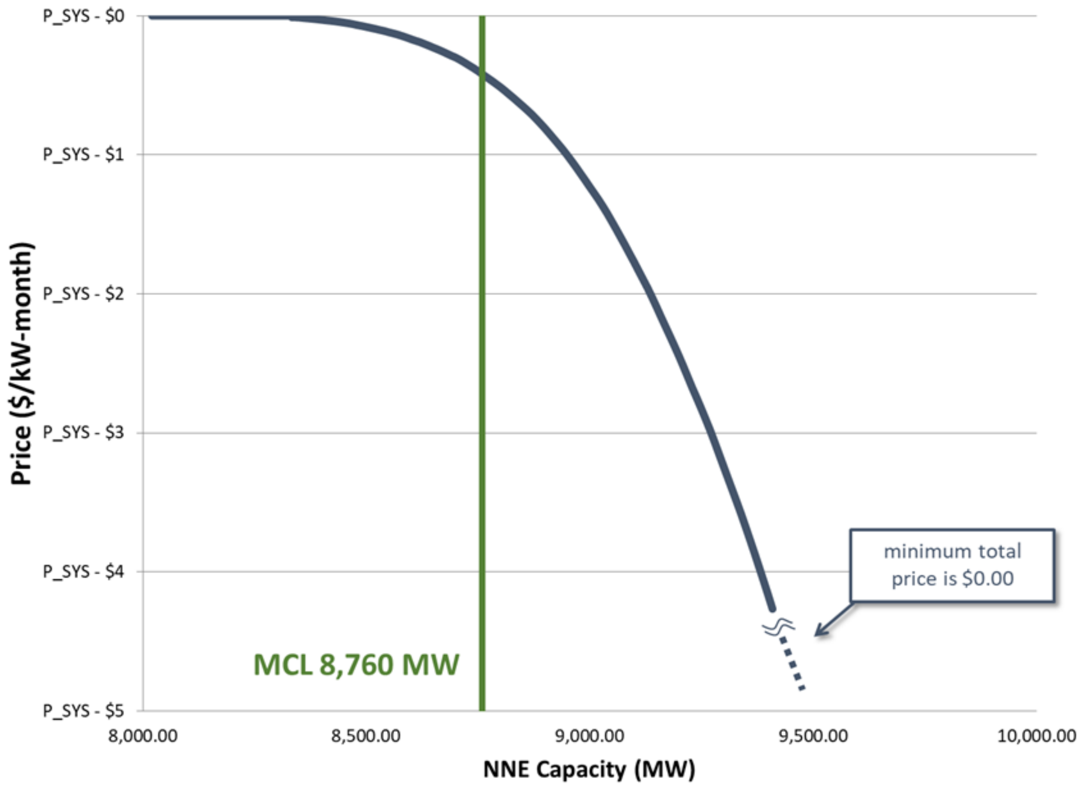
B. Export-Constrained Capacity Zone Demand Curves

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 18, there are two export-constrained Capacity Zone Demand Curves, Maine and NNE.

The following is the export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 18:


P_SYS - $0
P_SYS - $1
P_SYS - $2
P_SYS - $3
P_SYS - $4
P_SYS - $5
Price ($/kW-month)
3,500.00
4,000.00
4,500.00
5,000.00
ME Capacity (MW)
MCL 4,150 MW
minimum total price is $0.00

The following is the export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 18:



VII. STAKEHOLDER PROCESS

The ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR-Related Values for FCA 18 through an extensive stakeholder process over the course of six months, during which the Power Supply Planning Committee ("PSPC") and the Reliability Committee reviewed the calculation assumptions and methodologies, and discussed the proposed ICR-Related Values for FCA 18.

In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[41] Among other responsibilities, NESCOE is responsible for providing feedback on the

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[41] *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).

proposed ICR-Related Values at the relevant NEPOOL PSPC, Reliability Committee and Participants Committee meetings, and was in attendance for most meetings at which the ICR-Related Values for FCA 18 were discussed.

On September 19, 2023 the Reliability Committee voted to recommend that the Participants Committee support the HQICCs. Based on a voice vote, the motion passed with one opposition and fourteen abstentions. Also on September 19, 2023, the Reliability Committee voted to recommend that the Participants Committee support the proposed ICR-Related Values (*i.e*. the ICR, net ICR, MCLs for the Maine and NNE Capacity Zones, and MRI demand curves). The motion passed with one opposition and fourteen abstentions.

On October 5, 2023, the Participants Committee voted to support the proposed ICR-Related Values and HQICC values for FCA 18[42] as part of its Consent Agenda.[43]

VIII. REQUESTED EFFECTIVE DATE

The ISO requests that the Commission accept the proposed ICR-Related Values for FCA 18 to be effective on January 6, 2024 (which is 60 days from the filing date).

IX. ADDITIONAL SUPPORTING INFORMATION

This filing identifies ICR-Related Values for FCA 18 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.[44] 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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[42] Cross Sound Cable and the Long Island Power Authority opposed the values and stated as the basis for their opposition the lack of recognition of reliability value for the Cross Sound Cable in the calculation of tie benefits.

[43] The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's approval of the October 5, 2023 Consent Agenda included its support for the ICR-Related Values and the HQICC values filed herewith.

[44] 18 C.F.R. § 35.13.

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

- This transmittal letter;
- Attachment 1: Testimony of Manasa Kotha;
- Attachment 2: Testimony of Jonathan Black;
- Attachment 3: 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 6, 2024.

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) - The ISO's approval of the ICR-Related Values is evidenced by this filing. The ICR-Related Values reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of the Participants Committee.

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 proposed ICR-Related Values reflected in this submission for filing without change to become effective January 6, 2024.

Respectfully submitted,

ISO NEW ENGLAND INC.

By: *<u>/s/ Margoth Caley</u>*

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Attachments

cc: Entities listed in Attachment 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) **Docket No. ER24-___-000**

PREPARED TESTIMONY OF
MANASA KOTHA
ON BEHALF OF ISO NEW ENGLAND INC.

I. INTRODUCTION

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

A: My name is Manasa Kotha. I am employed by ISO New England Inc. (the "ISO") as the Supervisor of Capacity Requirement and Accreditation in the System Planning Department. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

Q: PLEASE DESCRIBE YOUR WORK EXPERIENCE AND EDUCATIONAL BACKGROUND.

A: As mentioned above, I am currently the Supervisor of the Capacity Requirement and Accreditation group at the ISO. In my current position, my team is responsible for the development of the Installed Capacity Requirement ("ICR") and related values for the Forward Capacity Auction ("FCA") and the annual reconfiguration auctions ("ARAs") conducted in the Forward Capacity Market ("FCM").[1]

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

Since 2019, I have worked for the Resource Adequacy & Accreditation[2] group conducting ICR and related values studies for the FCM. I also performed resource adequacy studies to support the ISO's Regional System Plan and reliability reporting requirements of the Northeast Power Coordinating Council, Inc. ("NPCC") and the North American Electric Reliability Corporation ("NERC"). Prior to that, I worked for 10 years in the Resource Analysis & Integration group, which is part of the ISO's System Planning Department. I was responsible for the qualification of Generating Capacity Resources, Demand Resources, and Import Capacity Resources for participation in the FCM. Prior to joining the ISO, I worked as a Software Engineer for Neumeric Technologies, where I developed software, carried out impact analysis, enhanced solutions by providing flexible business logic, testing code, and implementing quality management systems.

I have an M.S. in Electrical Engineering from the University of Missouri, Columbia, and a Bachelor of Technology in Electronics and Communication Engineering from Acharya Nagarjuna University, India.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

[2] Formerly the Resource Studies & Assessments group prior to a department re-organization in December 2022.

A: My testimony discusses the derivation of the ICR, net ICR, Maximum Capacity Limits ("MCLs") for the Maine and Northern New England ("NNE") Capacity Zones,[3] the Hydro-Quebec Interconnection Capability Credits ("HQICCs"), and the Marginal Reliability Impact ("MRI") demand curves for the 2027-2028 Capacity Commitment Period, which is associated with FCA 18, to be conducted beginning on February 5, 2024 The 2027-2028 Capacity Commitment Period starts on June 1, 2027 and ends on May 31, 2028. The ICR, MCLs for the Maine and the NNE Capacity Zones, HQICCs and MRI demand curves for FCA 18 are collectively referred to herein as the "ICR-Related Values."

Q: DID THE ISO CALCULATE LOCAL SOURCING REQUIREMENTS FOR FCA 18?

A: No. Pursuant to the Tariff, the ISO must calculate Local Sourcing Requirements (LSRs) for identified import Capacity Zones.[4] An LSR is the minimum amount of capacity that must be electrically located within an import-constrained Capacity Zone to meet the ICR.[5] Specifically, the LSR is calculated for an import-constrained Capacity Zone as the amount of capacity needed to satisfy the higher of (i) the Local Resource Adequacy or (ii) the Transmission Security Analysis requirements. However, for FCA 18, there are no

[3] In accordance with Section III.12.4 of the Tariff, the ISO determined that it will model three Capacity Zones in FCA 18: the Maine Capacity Zone, the NNE Capacity Zone and the Rest of Pool 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, Northeast MA (NEMA), Southeast MA (SEMA), Western/Central Massachusetts, and Rhode Island Load Zones.

[4] *See* Section III.12.4 of the Tariff.

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

import-constrained Capacity Zones. Thus, the ISO did not have to calculate LSRs and, accordingly, the methodologies described in this testimony do not include steps related to LSRs.

Q: PLEASE EXPLAIN WHY THERE WERE NO IMPORT-CONSTRAINED CAPACITY ZONES FOR FCA 18.

A: Similar to FCA 17, the import-constrained zone criterion testing that was conducted on the proposed Southeast New England ("SENE")[6] import-constrained Capacity Zone did not result in a need for the zone for FCA 18.[7]

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

A. Yes. As explained in the Testimony of Jonathan Black (submitted with this filing), this year, there are enhancements and updates to the methodologies used to develop the heating and transportation electrification forecasts. 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 the preceding FCA.

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[6] The proposed SENE import-constrained Capacity Zone includes the Southeast Massachusetts, Northeastern Massachusetts and Rhode Island Load Zones

[7] *See* May 31, 2023 Zonal Modeling for FCA 18 presentation to the Power Supply Planning Committee, available at: https://www.iso-ne.com/static-assets/documents/2023/05/a05_05312023_pspc_fca18_zone_formation-aff3d9d5.pdf

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 Section III.12.1, 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[s] 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 NPCC's Full Member Resource Adequacy Criterion (Resource Adequacy Requirement R4),[8] under which the ISO must probabilistically evaluate resource adequacy to demonstrate that the LOLE of

[8] *See Regional Reliability Reference Directory # 1 Design and Operation of the Bulk Power System* available at: https://www.npcc.org/content/docs/public/program-areas/standards-and-criteria/regional-criteria/directories/directory-01-design-and-operation-of-the-bulk-power-system.pdf

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 New England Power Pool ("NEPOOL") Load Forecast Committee, Power Supply Planning 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 5, 2023, the Participants Committee supported the HQICCs and the rest of the proposed ICR-Related Values (*i.e.* the ICR, net ICR, MCLs for the Maine and NNE Capacity Zones, and MRI demand curves) as part of its Consent Agenda.

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 ISO chairs the PSPC 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, Local Resource Adequacy Requirements ("LRAs"), 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.

Q: PLEASE IDENTIFY THE INSTALLED CAPACITY REQUIREMENT VALUE THAT THE ISO CALCULATED FOR FCA 18, WHICH IS ASSOCIATED WITH THE 2027-2028 CAPACITY COMMITMENT PERIOD.

A: The ICR value for FCA 18, which is associated with the 2027-2028 Capacity Commitment Period, is 31,591 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 ISO developed the System-Wide Capacity Demand Curve based on the net ICR of 30,550 MW, which is the 31,591 MW of ICR minus 1,041 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 18, which is associated with the 2027-2028 Capacity Commitment Period, New England did not need 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 18 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 related 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 30 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.

Q: PLEASE DESCRIBE THE FORECASTED LOAD WITHIN CAPACITY ZONES FOR FCA 18, WHICH IS ASSOCIATED WITH THE 2027-2028 CAPACITY COMMITMENT PERIOD.

A: The ISO developed the forecasted load for the Maine Capacity Zone using the load forecast for the State of Maine.

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

Q: WHAT DOES THE ISO CURRENTLY PROJECT TO BE THE NEW ENGLAND AND CAPACITY ZONE 50/50 AND 90/10 PEAK LOAD FORECAST FOR THE 2027-2028 CAPACITY COMMITMENT PERIOD?

A: The following table[9] shows the 50/50 and 90/10 peak load forecast for the 2027-2028 Capacity Commitment Period based on the 2023 load forecast as documented in the 2023-2032 Forecast Report of Capacity, Energy, Loads, and Transmission ("2023 CELT Report"). These values are reported as the "Net (with reductions for BTM PV)" load forecast.

[9] The values presented in the tables in this testimony have been rounded off to the nearest whole number.

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

	50/50	90/10
New England	27,440	29,302
Maine	2,170	2,302
NNE	5,605	5,905

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 18?

A: For FCA 18, 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 days 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: HOW IS TRANSPORTATION ELECTRIFICATION REFLECTED IN THE ICR MODEL?

A: Transportation electrification impacts both the summer and winter peak demands and monthly energy. As such, the impact of electric vehicle ("EV") load is explicitly modeled in the ICR calculation using an hourly EV demand forecast that reflects: (1) the assumed seasonal and weekday charging patterns; and (2) an 8% gross up for assumed transmission and distribution losses. The hourly EV forecast is modeled deterministically without considering uncertainty. This year's updates to the transportation electrification forecast are explained in the Testimony of Jonathan Black, submitted with this filing.

Q: HOW IS HEATING ELECTRIFICATION REFLECTED IN THE ICR MODEL?

A: Because heating electrification is weather-sensitive, it carries the load uncertainty associated with weather. Heating electrification only affects peak demand and energy in the winter months. Hence, to model it in the ICR, heating electrification is added into the gross load forecast, reflecting both the impacts from its penetration level and the uncertainty associated with weather. This year's updates and enhancements to the heating electrification forecast are explained in the Testimony of Jonathan Black, submitted with this filing.

2. RESOURCE CAPACITY RATINGS

Q: PLEASE DESCRIBE THE RESOURCE DATA THAT THE ISO USED TO DEVELOP THE ICR-RELATED VALUES FOR FCA 18, WHICH IS ASSOCIATED WITH THE 2027-2028 CAPACITY COMMITMENT PERIOD.

A: The ISO developed the ICR-Related Values for FCA 18 based on the Existing Qualified Capacity Resources for the 2027-2028 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 2027-2028 CAPACITY COMMITMENT PERIOD?

A: The following tables illustrate the make-up of the 32,760 MW of capacity resources assumed in the calculation of the ICR-Related Values.

Table 2 – Qualified Existing Non-Intermittent Generating Capacity Resources by Load Zone (MW)[10]

Load Zone	Summer
MAINE	2,920
NEW HAMPSHIRE	3,951
VERMONT	194
CONNECTICUT	9,547
RHODE ISLAND	1,896
SEMA	4,839
WESTERN/CENTRAL MASSACHUSETTS	3,620
NEMA/BOSTON	1,305
Total New England	**28,272**

[10] Values reflect the existing resources with Qualified Capacity for FCA 18 at the time of the ICR calculation and reflect applicable resource retirements and resource terminations.

Table 3 – Qualified Existing Intermittent Power Resources by Load Zone (MW)[11]

Load Zone	Summer	Winter
MAINE	294	306
NEW HAMPSHIRE	93	153
VERMONT	54	99
CONNECTICUT	114	67
RHODE ISLAND	158	192
SEMA	363	450
WESTERN/CENTRAL MASSACHUSETTS	214	136
NEMA/BOSTON	58	43
Total New England	1,347	1,447

Table 4 – Qualified Existing Import Capacity Resources (MW)

Import Resource	Summer	External Interface
NYPA – CMR	68	New York AC Ties
Niagara and St. Lawrence	15	New York AC Ties
Total New England	**84**	

Table 5 – Qualified Existing Demand Capacity Resources by Load Zone (Summer MW)

Load Zone	On-Peak	Seasonal Peak	Active Demand Capacity Resource (ADCR)	Total
MAINE	111	0	138	249
NEW HAMPSHIRE	131	0	47	178
VERMONT	101	0	54	155
CONNECTICUT	220	408	182	809
RHODE ISLAND	180	0	46	226
SEMA	289	0	88	377
WESTERN/CENTRAL MASSACHUSETTS	349	13	106	468
NEMA/BOSTON	476	0	119	594
Total New England	1,857	**421**	780	3,057

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

Although capacity resource data are tabulated above under the eight settlement Load Zones, only Maine (the Maine Load Zone) and NNE (the combined New Hampshire, Vermont and Maine Load Zones) are relevant for FCA 18.

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 $14.525 $/kW-month) are not assumed in the calculation of the ICR-Related Values for FCA 18, which is associated with the 2027-2028 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 18, WHICH IS ASSOCIATED WITH THE 2027-2028 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 Generator Availability Database System ("GADS") 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 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 Qualified Capacity of an Intermittent Power Resource is based on the resource's historical median output during the Reliability Hours averaged over a period of five years. The Reliability Hours are specific, defined hours during the summer and the winter, and hours during the year in which the ISO has declared a system-wide or a Load Zone-specific shortage event. Because this method already takes into account the resource's availability, Intermittent Power Resources are assumed to be 100% available in the models at their "Qualified Capacity" and not based on "nameplate" ratings. Qualified Capacity is the amount of capacity that either a generating, demand, or import resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the FCM qualification process.

Demand Capacity 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 Capacity Resources are assumed to be 100% available. The availability of Active Demand Capacity Resources is calculated on an annual basis for each Load Zone utilizing data from both summer and winter performance, weighing the seasons based on their relative duration throughout the year. A rolling average of the forced outage rate for Active Demand Capacity Resources is developed as a five year-rolling average.

Q: PLEASE LIST THE FOUR CATEGORIES OF BATTERY STORAGE RESOURCES AND HOW THEY ARE MODELED IN ICR CALCULATIONS BASED ON THEIR FCM PARTICIPATION.

A: Based on their FCM participation, the four categories of battery storage resources are:

(1) Battery storage resources that participate as Intermittent Power Resources (these may be co-located with other Intermittent Power Resources and may participate in the FCM as a single Intermittent Power Resource). The ISO models these resources using the methodology it uses to model Intermittent Power Resources (*i.e.*, using Qualified Capacity values and 100% availability).

(2) Co-located battery storage resources that participate as non-intermittent resources (these resources are co-located with Intermittent Power Resources, but participate as non-intermittent Generating Capacity Resources). The ISO models these co-located battery storage resources that participate as non-intermittent Generating Capacity Resources in the FCM using the methodology that it uses to model non-Intermittent Power Resources.

Specifically, the ISO uses the resources' Qualified Capacity values and assume 100% availability.

(3) Stand-alone battery storage resources, which participate in the FCM as non-intermittent Generating Capacity Resources. The ISO models these stand-alone battery storage resources using a class model. Specifically, all resources are modeled using the same typical design and operational parameters for the fleet. The parameters of the class model for GE MARS are:

- Maximum generation and charging rating: respective Qualified Capacity values
- Maximum energy: respective usable AC energy
- Round-trip efficiency: 84%
- Number of calls per day: 1
- Maximum energy per call: maximum energy x 98% (range between maximum and minimum usable state of charge).
- The EFORd of these battery storage resources is assumed to be 5% with zero weeks of maintenance;

(4) Battery storage resources that participate in the FCM as part of a Demand Capacity Resource.

4. OTHER ASSUMPTIONS

Q: PLEASE DESCRIBE THE ASSUMPTIONS RELATING TO INTERNAL TRANSMISSION TRANSFER CAPABILITIES FOR THE DEVELOPMENT OF ICR-RELATED VALUES FOR FCA 18.

A: The assumed internal interface transfer capabilities for export constrained Capacity Zones modeled are shown in the table below.

Table 6 – Internal Interface Transfer Capabilities (MW)

Interface	Contingency	2027-2028
Maine New Hampshire Export	N-1	1,900
Northern New England (North-South Interface)	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 18.

A: In the development of the ICR, MCLs and MRI demand curves, the ISO uses 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. These all constitute actions that system operators invoke under Operating Procedure No. 4 in real-time to balance system demand with supply under expected or actual capacity shortage conditions. The amount of load relief assumed obtainable from invoking 5% voltage reductions 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 262 MW for June through September 2027 and 224 MW for October 2027 through May 2028.

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 an MCL are modeled in the tie benefits study. The results of the tie benefits study are used as an input in the ICR, 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 that 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 18.

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

Pursuant to Section III.12.9 of the Tariff, the ICR calculations for FCA 18 assume total tie benefits of 2,115 MW based on the results of the tie benefits study for the 2027-2028 Capacity Commitment Period. A breakdown of this total value is as follows: 1,041 MW from Quebec over the Hydro-Quebec Phase I/II HVDC Transmission Facilities, 136 MW from Quebec over the Highgate interconnection, 544 MW from Maritimes (New Brunswick) over the New Brunswick interconnections, and 394 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 MW.

Q: IS THE ISO'S METHODOLOGY FOR CALCULATING TIE BENEFITS FOR FCA 18 THE SAME AS THE METHODOLOGY USED FOR FCA 17?

A: Yes. The methodology for calculating the tie benefits used in the ICR for FCA 18 is the same methodology used to calculate the tie benefits used in the ICR for FCA 17. 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 18.

A: The ISO conducted the tie benefits study for FCA 18 using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Control Areas of Quebec, New Brunswick, and New York. 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 ISO applied the "at criterion" approach 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 Quebec, Maritimes (New Brunswick) and New York were calculated first. To calculate total tie benefits, the ISO brought the interconnected system of New England and its directly interconnected neighboring Control Areas 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, the ISO calculated individual tie benefits from each of the three directly interconnected neighboring Control Areas. The ISO calculated tie benefits from each neighboring Control Area 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 is 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, the ISO calculated tie benefits 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 ISO adjusted the tie benefits for each individual interconnection or group of interconnections 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, then the ISO 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 18:

Table 7 – External Interface Import Capability (MW)

External Transmission Interconnections/Interfaces	Capacity Import Capability into New England
Hydro-Quebec Phase I/II HVDC Transmission Facilities	1,400
Highgate Interconnection	200
Maritimes (New Brunswick) Interconnections	700
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 2023, the ISO reviewed transfer limits of these external interconnections based on the latest available information regarding forecasted topology and load forecast information, and 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 the tie benefits for the 2027-2028 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 17.

III. MAXIMUM CAPACITY LIMITS

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 18?

A: After applying the export-constrained Capacity Zone objective criteria testing, it was determined that, for FCA 18, 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 IS THE LOCAL RESOURCE ADEQUACY ("LRA") REQUIREMENT AND HOW IS IT RELATED TO THE DETERMINATION OF AN MCL?

A: The LRA requirement is the minimum amount of resources required for an area to satisfy its reliability criterion. In the determination of the MCL of the export-constrained Capacity Zone of interest, the LRA requirement is used to identify the minimum amount of resources required for the "Rest of New England," which refers to all areas except the export-constrained Capacity Zone under study.

Q: PLEASE DESCRIBE THE METHODOLOGY FOR CALCULATING THE LRA FOR THE REST OF NEW ENGLAND.

A: The LRA requirement for the rest of New England is determined by modeling the export-constrained Capacity 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 areas are included in the model. Because the LRA requirement is the minimum amount of resources that must be located in the Rest of New England to meet the system-reliability requirements, the excess capacity in the export-constrained Capacity Zone of interest is shifted to the Rest of New England until the reliability threshold, or target LOLE of 0.105,[12] is achieved.

Q: WHAT ARE THE MAXIMUM CAPACITY LIMITS FOR THE EXPORT-CONSTRAINED CAPACITY ZONES FOR FCA 18 AND HOW WERE THEY CALCULATED?

A: The MCL for the Maine Capacity Zone for FCA 18 is 4,150 MW and the MCL for the NNE Capacity Zone is 8,760 MW which also reflect the tie benefits assumed available over the Maritimes (New Brunswick) and Highgate interfaces. The ISO calculated the MCLs 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. 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

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[12] 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.

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

V. HQICCs

Q: WHAT ARE HQICCs?

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

Q: WHAT ARE THE HQICC VALUES FOR FCA 18, WHICH IS ASSOCIATED WITH THE 2027-2028 CAPACITY COMMITMENT PERIOD?

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

A: The HQICC values are 1,041 MW for every month of the 2027-2028 Capacity Commitment Period.

VI. MRI DEMAND CURVES

Q: PLEASE DESCRIBE THE METHODOLOGY USED FOR CALCULATING THE MRI DEMAND CURVES FOR FCA 18.

A: To calculate the System-Wide Capacity Demand Curve and the export-constrained Capacity Zone Demand Curves for Maine and NNE for FCA 18, 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,[14] 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

[14] 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.

EENS. An MRI curve is developed from these values with capacity represented on the X-axis and the corresponding MRI values on the Y-axis.

MRI demand curve values at various capacity levels are also calculated for 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. These MRI values are calculated to reflect the change in system reliability associated with transferring incremental capacity from the Rest of New England 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-Wide Capacity Demand Curve and Capacity Zone Demand Curves for FCA 18 are set equal to the product of their MRI curves and a fixed demand curve scaling factor. The scaling factor is set equal to the lowest value at which the set of demand curves will simultaneously satisfy the planning reliability criterion and pay the estimated cost of new entry ("Net CONE").[15] In other words, the scaling factor is equal to the value that produces a

[15] For FCA 18, Net CONE has been determined as $9.078/kW-month.

System-Wide Capacity Demand Curve that specifies a price of Net CONE at the net ICR (ICR minus HQICCs).

To satisfy this requirement, the demand curve scaling factor for FCA 18 was developed for the System-Wide Capacity Demand Curve 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.

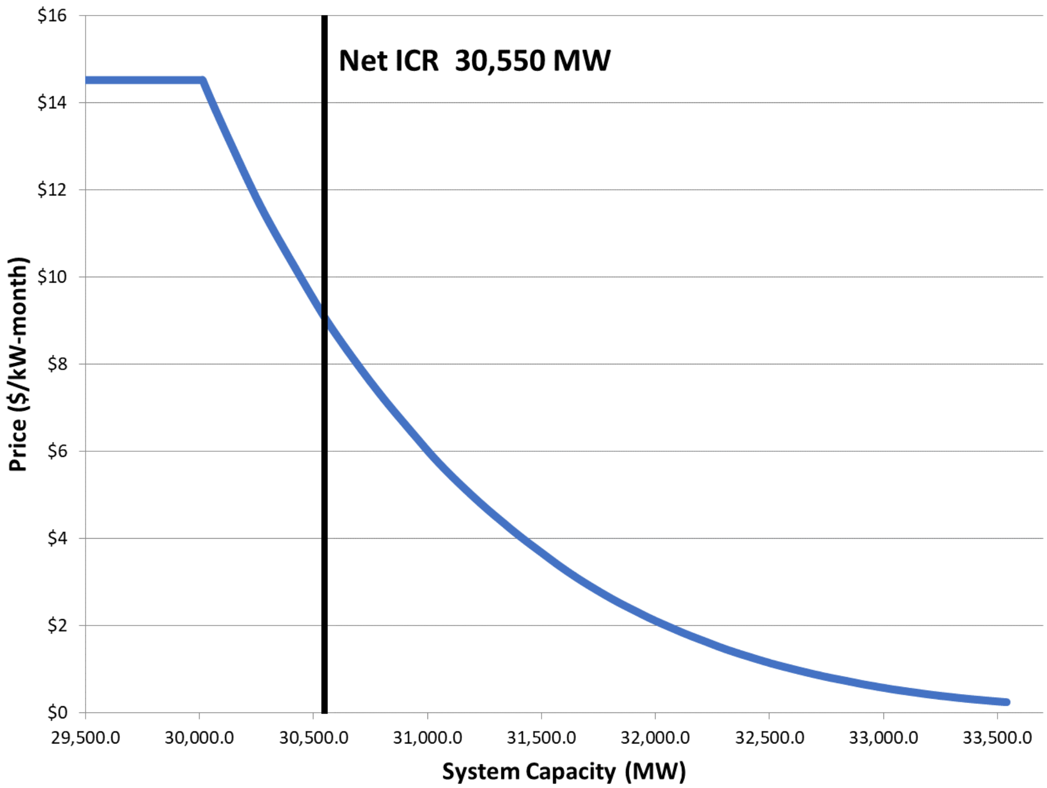
Q: PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE DEVELOPMENT OF THE EXPORT-CONSTRAINED CAPACITY ZONE DEMAND CURVES FOR THE MAINE AND NNE CAPACITY ZONES.

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 18, the export-constrained Capacity Zones are Maine and NNE, and, therefore, there are two export-constrained Capacity Zone Demand Curves.

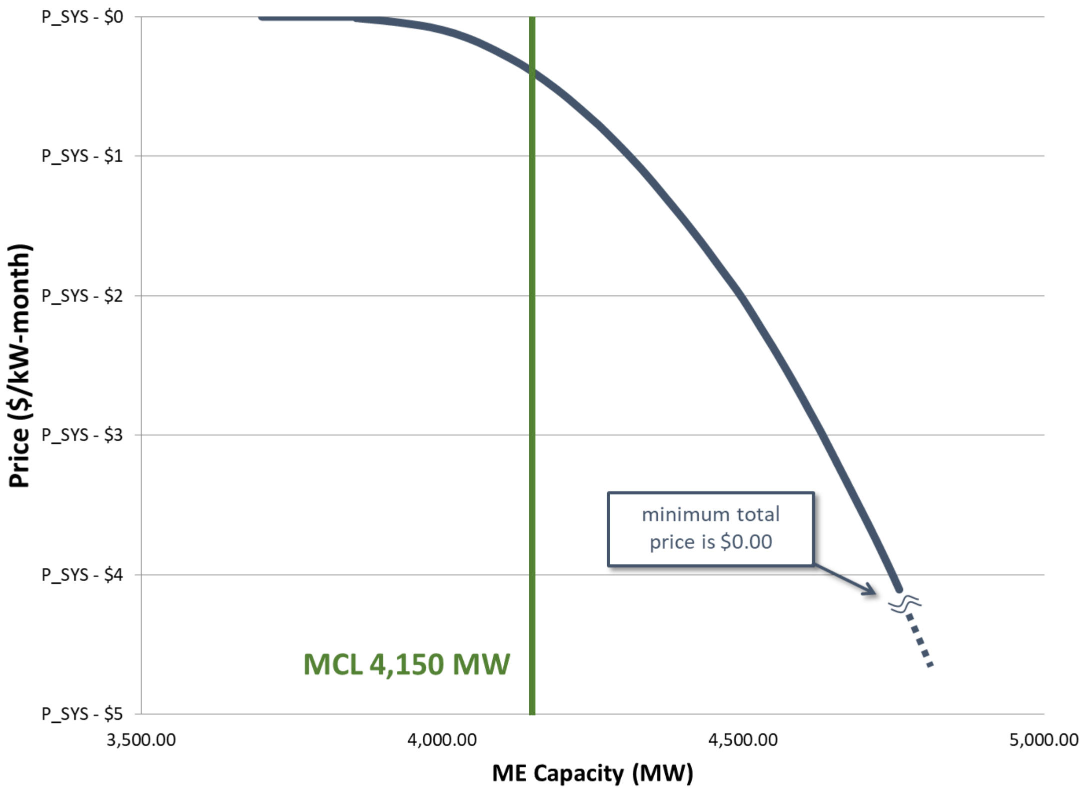
Q: WHAT MRI DEMAND CURVES HAS THE ISO CALCULATED FOR FCA 18?

A: As required under Section III.12 of the Tariff, the ISO calculated the following MRI demand curves for FCA 18:

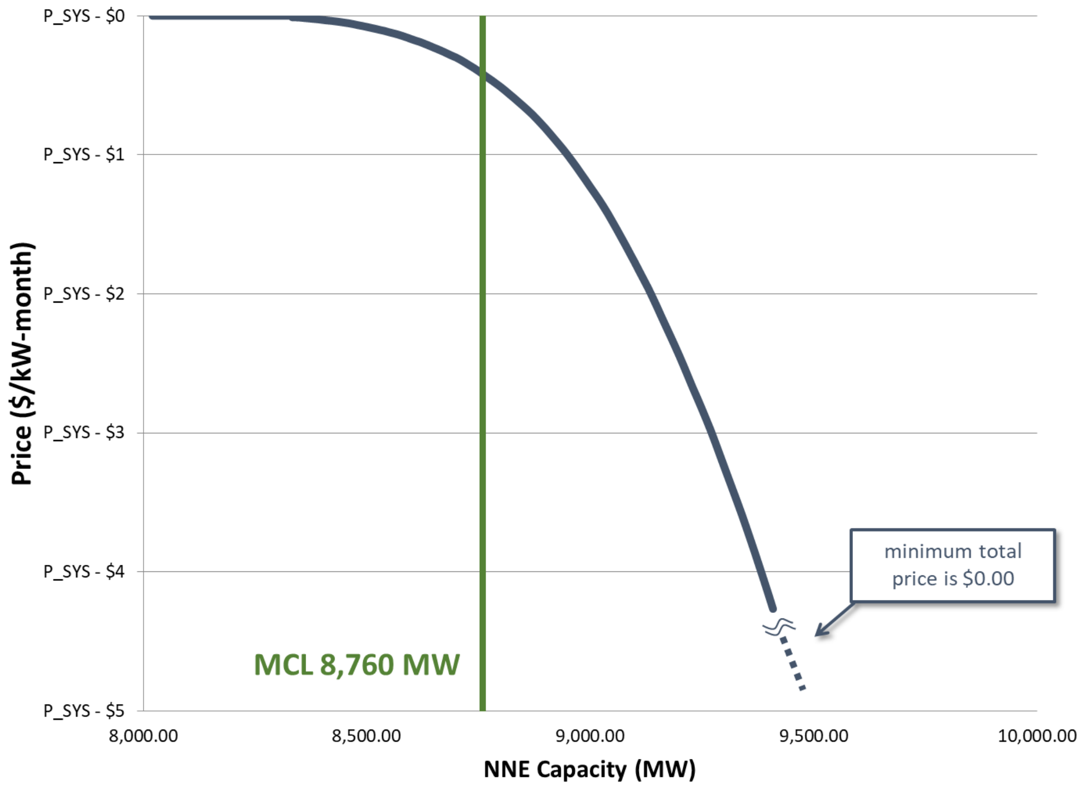
1. System-Wide Capacity Demand Curve for FCA 18



2. Export-constrained Capacity Zone Demand Curve for the Maine Capacity Zone for FCA 18



3. Export-constrained Capacity Zone Demand Curve for the NNE Capacity Zone for FCA 18



Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

I declare that the foregoing is true and correct.

Manasa K

Manasa Kotha

November 7, 2023

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc.) **Docket No. ER24-___-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 the System Planning Department. My business address is One Sullivan Road, Holyoke, Massachusetts 01040-2841.

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 seven years. In my current capacity, I am primarily responsible for the annual development of the long-term load, energy efficiency, heating and transportation electrification, and solar photovoltaic forecasts, as well as providing technical modeling support for short-term (*i.e.*, next seven days) 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.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: The purpose of my testimony is to explain the new methodology that the ISO used to develop the heating electrification forecast. My testimony also describes two updates to the transportation electrification forecast. The ISO incorporated both electrification forecasts into the load forecast assumption used in the calculation of the Installed Capacity Requirement[1] and related values for Forward Capacity Auction ("FCA") 18, which is associated with the 2027-2028 Capacity Commitment Period.

II. TESTIMONY

A. BACKGROUND

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

[1] Capitalized terms used but not defined in this testimony have the meanings ascribed to them in the ISO New England Transmission, Markets and Services Tariff ("Tariff").

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: 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: WHEN DID THE ISO DECIDE TO DEVELOP TRANSPORTATION ELECTRIFICATION AND HEATING ELECTRIFICATION FORECASTS?

A: The ISO decided to develop transportation electrification and heating electrification forecasts starting in 2020, *i.e.* for FCA 15 (associated with the 2024-2025 Capacity Commitment Period).[3] At the time, the ISO recognized that both transportation electrification and heating electrification are expected to play a pivotal role in the achievement of economy-wide greenhouse gas reduction mandates and goals that the New England states have established. As such, both transportation electrification and the growth of heating electrification impact electric energy consumption in New England.

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[2] More detailed information on the forecast methodology is available at: https://www.iso-ne.com/static-assets/documents/100003/lf2024_methodology.pdf

[3] The transportation electrification and heating electrification forecasts methodology used in 2020 is described in the Testimony of Jonathan Black, submitted as part of the ISO's filing of the ICR-Related Values for FCA 15. Available at: https://www.iso-ne.com/static-assets/documents/2020/11/icr_for_fca_15.pdf

B. HEATING ELECTRIFICATION FORECAST

Q: WHAT IS THE PURPOSE OF THE HEATING ELECTRIFICATION FORECAST?

A: The ISO's heating electrification forecast seeks to forecast the energy and demand impacts associated with the adoption of various forms of heat pumps to electrify residential space/water heating as well as commercial space/water heating.

Q: DID THE ISO UPDATE THE METHODOLOGY TO DEVELOP THE HEATING ELECTRIFICATION FORECAST FOR THE 2023 CAPACITY, ENERGY, LOADS, AND TRANSMISSION ("CELT") FORECAST?

A: Yes. For the 2023 CELT forecast, the ISO used a new methodology to develop the heating electrification forecast.[4]

Q: WHAT ARE THE MOST NOTABLE CHANGES TO THE ELECTRIFICATION FORECAST METHODOLOGY?

A: The most notable change to the heating electrification forecast methodology for CELT 2023 is that, this year, in addition to forecasting residential space heating (which was the only type of heating included in prior heating electrification forecasts), the ISO forecasted commercial space heating as well as residential and commercial water heating. Another notable change included a comprehensive characterization of New England's

[4] Details on the ISO's development of the heating electrification forecast are available at: http://www.iso-ne.com/static-assets/documents/2023/04/heatfx2023_final.pdf

existing building stock, which was subsequently used to inform all heat pump adoption forecasts, and associated energy and demand forecasts. This characterization leveraged the National Renewable Energy Laboratory's ResStock and ComStock datasets,[5] and yielded an inventory of the following building attributes: total building stock associated with 5 residential and 14 commercial building types; building age; heating fuel; heating delivery system; cooling delivery system; and location (state/county). Residential buildings are quantified in households, while commercial buildings are quantified in square feet.

Q: WERE OTHER METHODOLOGICAL CHANGES NEEDED TO DEVELOP THE HEATING ELECTRIFICATION FORECAST?

A: Yes, in order to complete the methodological enhancements, the ISO developed two other significant changes. First, for each sector, the ISO developed an array of "heating pathways" that specify a heat pump technology that could be used to either partially or fully electrify a given building's space or water heating needs. While the previous methodology only included 2 heating pathways for residential space heating, the updated methodology includes 7 pathways for residential space heating, 9 for commercial space heating, 1 for residential water heating, and 2 for commercial water heating. Second, the ISO developed mathematical models that, for any given outdoor ambient temperature,

[5] The NREL ResStock and ComStock datasets utilize a wide variety of data sources, surveys, studies and reports, including: EIA Residential Energy Consumption Survey (RECS); EIA Commercial Building Energy Consumption Survey (CBECS); American Community Survey (ACS) Public Use Microdata Sample (PUMS), American Housing Survey (AHS), DOE Commercial Prototype Buildings, as well as many other studies and reports along with commercially purchased and proprietary end-use data.

predict the electric heating demand for every possible combination of building type and heating pathway (*i.e*., a total of 40 residential and 154 commercial combinations).

Q: IN ADDITION TO THE METHODOLOGICAL CHANGES DESCRIBED, DID THE ISO UPDATE THE ADOPTION FORECAST THIS YEAR?

A: Yes. For CELT 2023, based on the new methodology described above, the ISO also had to update its adoption forecast such that it aligned with the updated building and heating pathway accounting. Specifically, this year, in addition to covering residential space heating (which was the only type of heating previously covered in the adoption forecast), the ISO also developed commercial space heating as well as residential and commercial water adoption forecasts. Lastly, the ISO developed building type and heating pathway attributes associated with each of these adoption forecasts.

Q: AT A HIGH LEVEL, HOW DID THE ISO DEVELOP ITS ENERGY AND ELECTRIC DEMAND FORECASTS?

A: As in previous years, the ISO developed its energy and electric demand forecasts by using the adoption forecast and the demand models. However, the improvements previously described resulted in the capability of forecasting a greater diversity of more detailed electrified heating outcomes that are better calibrated to the existing building stock and the types of heating and legacy heating fuels utilized in New England. Given the relative nascence of heating electrification in the region, this enhanced methodology will enable the ISO to adapt its forecasts over time as additional data on emerging heating trends becomes available.

C. TRANSPORTATION ELECTRIFICATION FORECAST

Q: WHAT IS THE PURPOSE OF THE 2023 TRANSPORTATION ELECTRIFICATION FORECAST?

A: The purpose of the transportation electrification forecast is to forecast the impacts of transportation electrification on state and regional electric energy and demand to include them as part of the 2023 CELT forecast. The ISO's transportation electrification forecast seeks to forecast the energy and demand impacts associated with the uptake of electric vehicles ("EVs") within selected categories of vehicles: light-duty personal vehicles, light-duty fleet vehicles, medium-duty delivery vehicles, school buses, and transit buses.

Q: PLEASE PROVIDE A HIGH LEVEL OVERVIEW OF THE METHODOLOGY THAT THE ISO USES TO DEVELOP THE TRANSPORTATION ELECTRIFICATION FORECAST.

A: To develop the transportation electrification forecast, first, the ISO forecasts the adoption of EVs (*i.e.*, the number of EVs purchased, registered, and driven over the forecast horizon) for each New England state and the New England region over the next ten years. Then, the ISO uses data-driven assumptions to convert the EV adoption forecast into estimated impacts on monthly energy and demand by New England state. The 2023 transportation electrification forecast includes an EV energy forecast (*i.e.*, estimates of monthly energy used for EV charging) and an EV demand forecast (which uses hourly weekday EV demand profiles to estimate the demand impacts of EV adoption).

Q: WERE THERE ANY UPDATES TO THE TRANSPORTATION ELECTRIFICATION FORECAST THIS YEAR?

A: Yes. This year, there were two updates to the transportation electrification forecast. First, as part of its annual revisiting of its state-level EV adoption forecasts, the ISO worked to develop a more consistent adoption forecasting framework that incorporated all federal, state, and local goals and mandates regarding EV adoption. Second, the ISO enhanced the modeling of weather sensitivity of the energy and demand impacts of personal light-duty vehicle EV charging. This aligned the methodology across all vehicle types, and moves from static monthly profiles to dynamic modeling of daily energy consumption based on weather.[6]

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

[6] Additional details on these updates to the transportation forecast are available at: https://www.iso-ne.com/static-assets/documents/2023/04/transfx2023_final.pdf

I declare that the foregoing is true and correct.

Jonathan Black

November 7, 2023

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