ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2018/19 Capacity Commitment Period

ISO New England Inc.
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Executive Summary

As part of the Forward Capacity Market (FCM), ISO New England Inc. (ISO-NE) conducts a Forward Capacity Auction (FCA) three years in advance of each Capacity Commitment Period (CCP) to meet the region's resource adequacy needs. The latest FCA, conducted on February 2, 2015, resulted in capacity (megawatts) commitments of sufficient quantities to meet the Installed Capacity Requirement (ICR) for the 2018/19 CCP. The 2018/19 CCP is the ninth CCP of the FCM (FCA9) and it begins on June 1, 2018 and ends on May 31, 2019.

This report documents the assumptions and simulation results of the 2018/19 CCP ICR, Local Sourcing Requirements (LSR) and Capacity Requirement Values for the System–Wide Capacity Demand Curve calculations – (collectively referred to as the "ICR Related Values"), all of which are key inputs in FCA9, along with the Hydro-Québec Interconnection Capability Credits (HQICCs), which are also a key input into the calculation of the ICR.

For the 2018/19 CCP, ISO-NE has identified three Load Zones that are import-constrained and as a result, modeled as Capacity Zones in FCA9. These Capacity Zones are: Connecticut, Northeast Massachusetts/Boston (NEMA/Boston) and the combined Load Zones of Southeastern Massachusetts and Rhode Island (SEMA/RI). [1] Therefore, the ICR Related Values for FCA9 consider three LSR values. The Maine Load Zone, which was modeled as an export-constrained Capacity Zone in prior FCAs, was determined not to be export-constrained. In fact, no Load Zones were considered to be export-constrained. Therefore the ICR Related Values for FCA9 do not consider any Maximum Capacity Limit (MCL) values.

In a filing, dated April 1, 2014, ISO-NE filed Market Rules relating to a System-Wide Capacity Demand Curve (Demand Curve) which was used for the first time in FCA9.[2] The Demand Curve has capacity requirement values which were calculated at the cap and foot[3] of the curve and are considered and filed as part of the ICR Related Values.

[1] The FERC filing identifying SEMA/RI as a Capacity Zone is available at: http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/may/er14_____000_5_8_14_iso_zone_boundry.pdf.
[2] The filing is available at: http://www.iso-ne.com/static-assets/documents/regulatory/ferc/filings/2014/apr/er14_1639_000_demand_curve_chges_4_1_2014.pdf.
[3] The design of the Demand Curve is specified in Section III.13.2.2. of the Market Rules which describes the cap as the Capacity Requirement Value at 0.200 LOLE, Max[1.6 x Net CONE,CONE] and the foot of the Demand Curve of Capacity Requirement Value at 0.011 LOLE, $0. See Figure 2 for the FCA9 Demand Curve.

As detailed below, ISO-NE has calculated an ICR of 35,142 MW. This value accounts for tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Québec of 1,970 MW, in aggregate, but it does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 953 MW per month is applied to reduce the portion of the ICR that is allocated to the Interconnection Rights Holders (IHR). Thus, the net amount of capacity to be purchased within the FCA to meet the ICR, after deducting the HQICC value of 953 MW per month, is 34,189 MW.

The LSR values associated with FCA9 for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones are 7,331 MW, 3,572 MW and 7,479 MW, respectively. As stated previously, there were no export-constrained zones modeled and as such, no MCL values were needed for FCA9.

Section III.12.1 of Market Rule 1 states that the Demand Curve will be calculated using the same methodology as the ICR calculation.

"*The ISO shall determine, by applying the same modeling assumptions and methodology used in determining the Installed Capacity Requirement, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve*."

As such, the capacity requirements at the Demand Curve cap and foot, calculated at a 1 day in 5 years (1-in-5) Loss of Load Expectation (LOLE), and a 1 day in 87 years (1-in-87) LOLE are 33,132 MW and 37,027 MW, respectively.

As in past years, ISO-NE developed the initial ICR recommendation with stakeholder input, which was provided in part through the NEPOOL committee processes through review by NEPOOL's Power Supply Planning Committee (PSPC) during the course of four meetings, by the NEPOOL Reliability Committee (RC) at its September 16, 2014 meeting and by the NEPOOL Participants Committee (PC) at its October 3, 2014 meeting.[4] In addition, the New England States Committee on Electricity (NESCOE) provided feedback on the proposed ICR Related Values at the relevant NEPOOL committee meetings. Representatives of NESCOE provided feedback at discussions of the ICR Related Values assumptions at the PSPC and were in attendance for the RC and PC meetings at which the ICR Related Values for FCA9 were discussed and voted.

After the NEPOOL committee voting process was completed, ISO-NE filed the ICR Related Values and HQICCs for the 2018/19 FCA with the FERC in a filing dated

[4] All of the load and resource assumptions needed for the General Electric Multi-Area Simulation ("GE MARS") model used to calculate tie benefits and the ICR Related Values were reviewed by the PSPC, a subcommittee of the NEPOOL Reliability Committee (RC). The NEPOOL Load Forecast Committee (LFC), also a subcommittee of the NEPOOL Reliability Committee, reviews the load forecast assumptions and methodology.

November 4, 2014.[5] The FERC accepted the ICR Related Values in a letter dated January 2, 2015.[6]

Table 1 shows the ICR Related Values for the 2018/19 CCP. The monthly values for the HQICCs are provided in Table 2.

Table 1: Summary of 2018/19 ICR Related Values (MW)[7,8]

2018/19 FCA	New England	Connecticut	NEMA/ Boston	SEMA/RI
Peak Load (50/50)	30,005	7,725	6,350	5,910
Existing Capacity Resources	32,842	9,239	3,868	6,984
Installed Capacity Requirement	35,142			
NET ICR (ICR Minus 953 MW HQICCs)	34,189			
Capacity Requirement at 1-in-5 LOLE	33,132			
Capacity Requirement at 1-in-87 LOLE	37,027			
Local Sourcing Requirements		7,331	3,572	7,479

Table 2: Monthly HQICCs (MW)

2018/19 CCP Month	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19
HQICC Values	953	953	953	953	953	953	953	953	953	953	953	953

5 The ISO-NE filing is located at http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-6-14_2018-2019_icr_filing.pdf.
6 The FERC Order accepting the ICR Values for the 2018/19 FCA is available at: http://www.iso-ne.com/static-assets/documents/2015/01/er15-325-000_1-2-15_order_accept_2018-2019_icrs.pdf.
7 After reflecting a reduction in capacity requirements relating to the 953 MW of HQICCs that are allocated to the Interconnection Rights Holders (IHR), the net amount of capacity to be procured within the Forward Capacity Auction to meet the ICR is the Net ICR value of 34,189 MW.
8 Existing Capacity Resource value for New England excludes HQICCs.

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Introduction

The Installed Capacity Requirement (ICR) is a measure of the installed resources that are projected to be necessary to meet both ISO New England's (ISO-NE) and the Northeast Power Coordination Council's (NPCC) reliability standards[9], with respect to satisfying the peak demand forecast for the New England Balancing Authority area while maintaining required reserve capacity. More specifically, the ICR is the amount of resources (MWs) needed to meet the reliability requirements defined for the New England Balancing Authority area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE"), on average, no more than once every ten years (an LOLE of 0.1 days per year). This criterion takes into account: other possible levels of peak electric loads due to weather variations, the impacts of resource availability, and the potential load and capacity relief obtainable through the use of ISO New England Operating Procedure No. 4 – *Actions During a Capacity Deficiency* (OP-4).[10]

This report discusses the derivation of the ICR, Local Sourcing Requirements (LSR) and the capacity requirement values for the System-Wide Capacity Demand Curve ("Demand Curve") (collectively, the "ICR Related Values")[11], along with the Hydro-Québec Interconnection Capability Credits (HQICCs) for the 2018/19 CCP's Forward Capacity Auction (FCA) conducted on February 2, 2015. The 2018/19 CCP starts on June 1, 2018 and ends on May 31, 2019.

This report documents the general process and methodology used for developing the assumptions utilized in calculating the ICR, including assumptions about load, resource capacity values and availability, load relief from OP-4, and transmission interface transfer capabilities and the methodology used for calculating the ICR. Also discussed are the calculation of LSR for import-constrained Load Zones, including the Local Resource Adequacy (LRA) Requirements and Transmission Security Analysis (TSA) Requirements that are inputs into the calculation of LSR along with the calculation of the MCL for export-constrained Capacity Zones which were not required as part of FCA9. In general, the methodology used for calculating the ICR Related Values for the 2018/19 FCA remains unchanged from the methodology used for calculating the prior ICR Related Values for the 2017/18 FCA, with the exception of the additional calculation of the capacity requirements for the Demand Curve, which was used for the first time in FCA9.

[9] Information on the NPCC Standards is available at: https://www.npcc.org/Standards/default.aspx.
[10] ISO-NE OP-4 is located at: http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.
[11] For FCA9, no zones were determined to be export-constrained and therefore, no Maximum Capacity Limit (MCL) values were filed as part of FCA9.

Summary of ICR Related Values and Components for 2018/19

Table 3 documents the ICR Related Values and components relating to the calculation of ICR.

Table 3: ICR Related Values and Components for 2018/19 (MW)[12]

2018/19 FCA	New England	Connecticut	NEMA/ Boston	SEMA/RI
Peak Load (50/50)	30,005	7,725	6,350	5,910
Existing Capacity Resources	32,842	9,239	3,868	6,984
Installed Capacity Requirement	35,142			
NET ICR (ICR Minus 953 MW HQICCs)	34,189			
Capacity Requirement at 1-in-5 LOLE	33,132			
Capacity Requirement at 1-in-87 LOLE	37,027			
Local Sourcing Requirements		7,331	3,572	7,479

The 35,142 MW ICR value does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders (IRH) in accordance with Section III.12.9.2 of Market Rule 1. After deducting the monthly HQICC value of 953 MW, the net Installed Capacity Requirement for use in the 2018/19 FCA is 34,189 MW, which is described as the "*Net ICR*".

The 34,189 MW of Net ICR, which excludes HQICCs, results in an Annual Resulting Reserve Margin value of 13.9%. The Annual Resulting Reserve Margin is a measure of the amount of resources potentially available in excess of the 50/50 seasonal peak load forecast value and is calculated as:

Figure 1: Formula for Annual Resulting Reserve Margin (%)

Annual Resulting Reserve Margin (%) =
((ICR-HQICCs-Annual 50/50 Peak Load) / (Annual 50/50 Peak Load)) x 100

The 13.9% Annual Resulting Reserving Margin is a slight increase from the 13.6% value calculated for the 2017/18 FCA. While some changes in ICR assumptions decreased the reserve margin, some do cause it to increase, particularly assumptions related to an increase in the generator forced outage rates. Overall, the net change in reserve margin was small. The increase in generator unavailability and other changes, along with the

[12] Existing Capacity Resource value for New England excludes HQICCs.

overall change in ICR, is discussed in more detail in the last section of this report, *Difference from the 2017/18 FCA ICR Related Values*.

The capacity requirement values for the Demand Curve, calculated for the first time for FCA9 require that:

"*The ISO shall determine, by applying the same modeling assumptions and methodology used in determining the Installed Capacity Requirement, the capacity requirement value for each LOLE probability specified in Section III.13.2.2 for the System-Wide Capacity Demand Curve*"

according to Section III.12.1 of Market Rule 1.

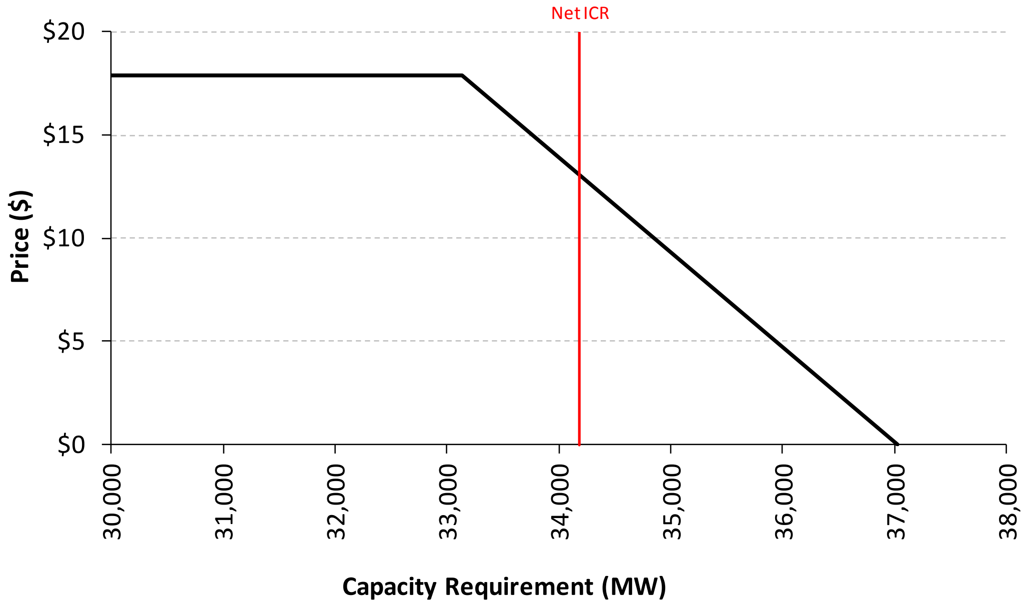
As such, the capacity requirement values at the Demand Curve cap and foot, calculated at 1 day in 5 years (1-in-5) Loss of Load Expectation (LOLE), and at 1 day in 87 years (1-in-87) LOLE are 33,132 MW and 37,027 MW, respectively.

The coordinates of the Demand Curve use a price quantity for the Cost of New Entry (CONE) into the capacity market. This price quantity is determined as max [1.6 times Net CONE, CONE]. CONE for the FCA for the 2018/19 CCP is $14.04/kW-month while Net CONE is $11.08/kW-month.[13]

Using the coordinates of the cap of the Demand Curve of [Capacity Requirement Value at 1-in-5 LOLE, 1.6 x Net CONE ($17.728] and the foot of the Demand Curve of [Capacity Requirement Value at 1-in-87 LOLE, $0], the Demand Curve for FCA9 is shown in Figure 2.

[13] The determination of CONE for 2018/19 was discussed at the March 12, 2014 Markets Committee: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/mrkts_comm/mrkts/mtrls/2014/mar12132014/a02a_the_brattle_group_demand_curve_net_cone_final_proposal_03_12_14.pptx. For rules relating to CONE, see Market Rule 1 III.13.2.4.

Figure 2: System-Wide Capacity Demand Curve for 2018/19 (FCA9)



A summary of historical ICR Related Values, including links to documentation and filings for FCA9 and prior years are available on the ISO-NE website under System Planning > Installed Capacity Requirements > Summary of Historical ICR Values (EXCEL Spreadsheet) and can be directly accessed at this link: http://www.iso-ne.com/static-assets/documents/2014/12/summary_of_icr_values_expanded.xlsx.

Stakeholder Process

As in past years, ISO-NE developed the initial ICR recommendation with stakeholder input, which was provided in part through the NEPOOL committee process with review by NEPOOL's Power Supply Planning Committee (PSPC) during the course of four meetings. The PSPC, which is chaired by ISO-NE, is a non-voting, technical subcommittee reporting to the NEPOOL Reliability Committee (RC). Most PSPC members are representatives of NEPOOL Participants. The PSPC assists ISO-NE with the development of resource adequacy based requirements such as the ICR, LSR, MCL and Demand Curve capacity requirements, including the appropriate load and resource assumptions for modeling expected power system conditions.

As part of the stakeholder voting process, the ICR Related Values was vetted through the RC at its September 16, 2014 meeting and acted on by the NEPOOL Participants Committee (PC) at its October 3, 2014 meeting.[14] Representatives of the New England States Committee on Electricity ("NESCOE") provided feedback on the proposed ICR Related Values at the relevant NEPOOL PSPC, RC and PC meetings, and were in attendance for the meetings at which the ICR Related Values for the 2018/19 Forward Capacity Auction were discussed and voted.

At the September 16, 2014 meeting of the RC, a motion to recommend support of the ICR Related Values passed by a show of hands, with four opposed (1 Transmission Sector, 1 Publicly Owned Sector, and 2 Supplier Sector) and one abstention (1 Transmission Sector). A motion that the RC recommend that the PC support the HQICC values passed by a show of hands, with two opposed (2 Supplier Sector) and one abstention (1 Supplier Sector).

At the October 3, 2014 PC meeting, the ICR Related Values and HQICC Values were removed as part of the Consent Agenda due to concerns by some Stakeholders that ISO-NE *"failed to recognize a present and continuing investment in renewable distributed generation resources."*[15] Specifically they believed the load forecast, as an input into the ICR Related Values, should be decreased by an appropriate forecast of photovoltaic resources in the 2018/19 CCP. The vote on ICR Related Values subsequently failed at the PC.[16]

[14] All of the load and resource assumptions needed for the General Electric Multi-Area Simulation (GE MARS) model used to calculate tie benefits and the ICR Related Values were reviewed by the PSPC, a subcommittee of the NEPOOL RC. The NEPOOL Load Forecast Committee (LFC), also a subcommittee of the NEPOOL RC, reviews the load forecast assumptions and methodology.

[15] The memo is part of the October 3, 2014 PC Meeting materials at http://www.iso-ne.com/static-assets/documents/2014/10/NPC_20141003_Addl.pdf.

[16] At the PC, the vote on the FCA9 ICR Related Values failed with a 38.61% vote in favor (Generation – 17.17%, Transmission – 0%; Supplier – 15.60%; Alternative Resources – 4.28%; Publicly Owned Entity – 0%; and End User – 1.56%).

ISO-NE filed the ICR Related Values and HQICCs for the 2018/19 FCA with the FERC on November 4, 2014.[17] The FERC accepted the ICR Related Values in a letter dated January 2, 2015.[18]

[17] A copy of the filing is available at: http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-6-14_2018-2019_icr_filing.pdf.

[18] The FERC Order accepting the ICR Values for the 2018/19 FCA is available at: http://www.iso-ne.com/static-assets/documents/2015/01/er15-325-000_1-2-15_order_accept_2018-2019_icrs.pdf.

Methodology

Reliability Planning Model for ICR Related Values

The ICR is the minimum level of capacity required to meet the reliability requirements defined for the New England Balancing Authority area. This requirement is documented in Section 2 of ISO New England Planning Procedure No. 3,[19] *Reliability Standards for the New England Area Bulk Power Supply System*, which states:

> *"Resources will be planned and installed in such a manner that, after due allowance for the factors enumerated below, the probability of disconnecting non-interruptible customers due to resource deficiency, on the average, will be no more than once in ten years. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting non-interruptible customers due to resource deficiencies shall be, on average, no more than 0.1 day per year."*

Included as variables within the reliability model are:

a. The possibility that load forecasts may be exceeded as a result of weather variations.
b. Immature and mature equivalent forced outage rates appropriate for resources of various sizes and types, recognizing partial and full outages.
c. Due allowance for generating unit scheduled outages and deratings.
d. Seasonal adjustments of resource capability.
e. Proper maintenance requirements.
f. Available operating procedures.
g. The reliability benefits of interconnections with systems that are not Governance Participants.
h. Such other factors as may be appropriate from time to time.

The ICR for the 2018/19 CCP was established using the General Electric Multi-Area Reliability Simulation Model (GE MARS). GE MARS is a computer program that uses a sequential Monte Carlo simulation to probabilistically compute the resource adequacy of a bulk electric power system by simulating the random behavior of both loads and resources. For the ICR calculation, the GE MARS model is used as a one-bus model and the New England transmission system is assumed to have no constraints within this simulation. In other words, all the resources modeled are assumed to be able to deliver their full output to meet forecast load requirements.

To calculate the expected days per year that the bulk electric system would not have adequate resources to meet peak demands and required reserves, the GE MARS Monte Carlo process repeatedly simulates the year using multiple replications and evaluates the impacts of a wide-range of possible random combinations of resource outages.

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

Chronological system histories are developed by combining randomly generated operating histories of the resources serving the hourly chronological demand. For each hour, the program computes the isolated area margins based on the available capacity and demand within each area. The program collects the statistics for computing the reliability indices and then proceeds to the next hour to perform the same type of calculation. After simulating all of the hours in the year, the program computes the annual indices and tests for convergence. If the simulation has not converged to an acceptable level, it proceeds to another replication of the study year.

Installed Capacity Requirement (ICR) Calculation

The formula for calculating the New England ICR is:

Figure 3: Formula for ICR Calculation

$$Installed\ Capacity\ Requirement\ (ICR) = \frac{Capacity - Tie\ Benefits - OP4\ Load\ Relief}{1 + \frac{ALCC}{APk}} + HQICCs$$

Where:	APk	= Annual 50/50 Peak Load Forecast for summer
	Capacity	= Total Capacity (sum of all supply and demand resources)
	Tie Benefits	= Tie Reliability Benefits
	OP-4 Load Relief	= Load relief from ISO-NE OP-4 - Actions 6 & 8 and the modeling of the minimum 200 MW Operating Reserve limit
	ALCC	= Additional Load Carrying Capability (as determined by the % of peak load)
	HQICCs	= Monthly HQICC value[20]

The ICR formula is designed such that the results identify the minimum amount of capacity required to meet New England's resource adequacy criterion of expecting to interrupt non-interruptible load, on average, no more than once every ten years. 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. For the 2018/19 CCP, the New England system, using the resources that qualified as Existing Capacity, is less reliable than the resource adequacy criterion requirement. Therefore, additional capacity in the form of proxy units is needed within the model. Proxy units are used if existing capacity resources are insufficient to meet the resource adequacy planning criterion, as provided by Section III.12.7.1 of Market Rule 1. Proxy units are assigned availability characteristics such that when proxy resources are used in place of all the resources assumed to be available to the system, the resulting system LOLE remains unchanged from that calculated using the existing resources. The use of proxy units to meet the

[20] In the ICR calculation, the HQICCs are treated differently than other resources; they are not adjusted by the ALCC amount.

system LOLE criterion is intended to neutralize the size and availability impact of unknown resource additions on the ICR.

Prior to the calculation of ICR Related Values for the 2018/19 CCP, ISO-NE conducted a study to update the size and availability characteristics of the proxy units used in the analysis.[21] In the study, proxy unit characteristics are determined using the average system availability and a series of LOLE calculations. Using these characteristics gives a proxy unit that when added to the model, does not increase or decrease ICR. For more details on the proxy unit characteristics, see the section of this report entitled "*Proxy Units.*"

To determine the ICR for the 2018/19 CCP, four proxy units were needed in addition to the existing capacity within the ICR model. In addition, for the 1-in-5 LOLE and the 1-in-87 LOLE capacity requirements calculations for the Demand Curve, one proxy unit was needed and14 proxy units were needed, respectively.

Table 4 shows the details of the variables used to calculate the ICR for the 2018/19 CCP.

Table 4: Variables Used to Calculate ICR and Demand Curve (MW)

Total Capacity Breakdown	1-in-5 LOLE	2018/19 FCA ICR	1-in-87 LOLE
Generating Resources	29,829	29,829	29,829
Tie Benefits	1,970	1,970	1,970
Imports/Sales	(41)	(41)	(41)
Demand Resources	3,054	3,054	3,054
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
Proxy Unit Capacity	400	1,600	4,400
Total Capacity	**35,453**	**36,653**	**39,453**
Installed Capacity Requirement Calculation Details	**1-in-5 LOLE**	**2018/19 FCA ICR**	**1-in-87 LOLE**
Annual Peak	30,005	30,005	30,005
Total Capacity	35,453	36,653	39,453
Tie Benefits	1,970	1,970	1,970
HQICCs	953	953	953
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	99	222	175
Installed Capacity Requirements	**34,085**	**35,142**	**37,980**
Net ICR	**33,132**	**34,189**	**37,027**
Reserve Margin without HQICCs	10.4%	13.9%	23.4%

Local Sourcing Requirements (LSR) Calculation

The methodology for calculating LSR for import-constrained Capacity Zones involves calculating the amount of resources located within the Capacity Zone that would meet

[21] Study results presented at the May 22, 2014 PSPC Meeting: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf.

both a local criterion requirement called the Local Resource Adequacy (LRA) Requirement and a transmission security criterion called the Transmission Security Analysis (TSA) Requirement. The TSA Requirement is an analysis that ISO-NE uses to maintain operational reliability when reviewing de-list bids of resources within the FCM auctions. The system must meet both resource adequacy and transmission security requirements; therefore, the LSR for an import-constrained zone is the amount of capacity needed to satisfy *"the higher of"* either (i) the LRA or (ii) the TSA Requirement.

Local Resource Adequacy (LRA) Requirement

The LRA Requirements are calculated using the same assumptions for forecasted load and resources as those used within the calculation of the ICR. To determine the locational requirements of the system, the LRA Requirements are calculated using the multi-area reliability model, GE MARS, according to the methodology specified in Section III.12.2 of Market Rule 1.

The LRA Requirements are calculated using the value of the firm load adjustments and the existing resources within the zone, including any proxy units that were added as a result of the total system not meeting the LOLE criteria. Because the LRA Requirement is the minimum amount of resources that must be located within a zone to meet the system reliability requirements, for a zone with excess capacity, the process to calculate this value involves shifting capacity out of the zone under study until the reliability threshold, or target LOLE, is achieved. Shifting capacity, however, may lead to skewed results, since the load carrying capability of various resources are not homogeneous. For example, one megawatt of capacity from a nuclear power plant does not necessarily have the same load carrying capability as one megawatt of capacity from a wind turbine. Consequently, in order to model the effect of shifting "generic" capacity, firm load is shifted. Specifically, as one megawatt of load is added to an import-constrained zone, a megawatt of load is subtracted from the rest of New England, thus keeping the entire system load constant. The load that was shifted must be subtracted from the total resources (including proxy units) to determine the minimum amount of resources that are required in that zone. Before the shifted load is subtracted, it is first converted to equivalent capacity by using the average resource-unavailability rate within the zone. Thus, the LRA Requirement is calculated as the existing resources in the zone including any proxy units, minus the unavailability-adjusted firm load adjustment.

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

For each import-constrained transmission Capacity Zone, the LRA Requirement is calculated using the following methodology, as outlined in Market Rule 1, Section III.12.2.1:

a) Model the Capacity Zone under study and the *Rest of New England* area using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Balancing Authority area support from tie benefits.

b) If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

c) Model the transmission interface constraint between the Load Zone under study and the *Rest of New England*.

d) Add proxy units, if required, within the ISO-NE Balancing Authority Area to meet the resource adequacy planning criterion of once in 10 year disconnection of non-interruptible customers. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year. Proxy units are modeled as stated in Section III.12.7.1 of Market Rule 1.

e) Adjust the firm load within the Capacity Zone under study until the LOLE of the ISO-NE Balancing Authority Area reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the Capacity Zone under study, an equal amount of firm load is removed from (or added to) the *Rest of New England*.

The LRA Requirement is then calculated using the formula:

Figure 4: Formula for LRA Calculation

$$LRA_Z = Resources_Z + Proxy\ Units_Z - \left(\frac{Firm\ Load\ Adjustment_Z}{1 - FOR_Z}\right)$$

Where	LRA_z	= Local Resource Adequacy Requirement for Capacity Zone Z.
	$Resources_z$	= MW of resources (supply & demand-side) electrically located within Load Zone Z, including Import Capacity Resources on the import-constrained side of the interface, if any and excludes HQICCs.
	Proxy $Units_z$	= MW of proxy unit additions, if needed, in Capacity Zone Z.
	Firm Load $Adjustment_z$	= MW of firm load added within Capacity Zone Z to make the LOLE of the New England Balancing Authority area equal to 0.105 days per year.
	FOR_z	= Capacity weighted average of the forced outage rate modeled for all resources (supply & demand-side) within Capacity Zone Z, including any proxy unit additions to Capacity Zone Z.

In addition, when performing the LRA calculation for the *Rest of New England* area used in the calculation of local requirements for export-constrained zones, the surplus capacity adjustment used to bring the system to the 0.1 days per year reliability criterion is also included in the calculation as:

Figure 5: Surplus Capacity Adjustment in *Rest of New England*

$$-\left(\frac{Surplus\ Capacity\ Adjustment_Z}{1 - FOR_Z}\right)$$

Where:

Surplus Capacity $Adjustment_z$ = MW of firm load added within Zone Z to make the LOLE of the New England Balancing Authority area equal to 0.1 days per year

Table 5 shows the details of the LRA Requirement calculation for the 2018/19 CCP.

Table 5: LRA Requirement Calculation Details (MW)

		Connecticut	NEMA/Boston	SEMA/RI
$Resource_z$	[1]	9,239	3,868	6,984
Proxy $Units_z$	[2]	0	0	800
Firm Load $Adjustment_z$	[4]	1,825	775	278
FOR_z	[5]	0.074	0.042	0.090
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**7,268**	**3,129**	**7,479**

Transmission Security Analysis (TSA) Calculation

The TSA is a deterministic reliability screen of a transmission import-constrained area and is a security review as defined within Section 3 of ISO New England Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power Supply System* and within Section 5.4 of Northeast Power Coordinating Council's (NPCC)

Regional Reliability Reference Directory #1, *Design and Operation of the Bulk Power System*.[22] The TSA review determines the requirements of the sub-area in order to meet its load through internal generation and import capacity. It is performed via a series of discrete transmission load flow study scenarios. In performing the analysis, static transmission interface transfer limits are established as a reasonable representation of the transmission system's capability to serve sub-area demand with available existing resources. The results are then presented in the form of a deterministic operable capacity analysis.

In accordance with ISO New England Planning Procedure No. 3 and NPCC's Regional Reliability Reference Directory #1, the TSA includes evaluations of both: (1) the loss of the most critical transmission element and the most critical generator (Line-Gen), and (2) the loss of the most critical transmission element followed by loss of the next most critical transmission element (Line-Line). These deterministic analyses are currently used each day by ISO-NE System Operations to assess the amount of capacity required to be committed day-ahead within import-constrained Capacity Zones. Further, such deterministic sub-area transmission security analyses have consistently been used for reliability review studies performed to determine whether a resource seeking to retire or de-list would cause a violation of the reliability criteria.

Figure 6 shows the formula used in the calculation of TSA requirements.

Figure 6: Formula for TSA Requirements

$$\text{TSA Requirement} = \frac{(\text{Need} - \text{Import Limit})}{1 - (\text{Assumed Unavailable Capacity} / \text{Existing Resources})}$$

Where:

Need =	Load + Loss of Generator ("Line-Gen" scenario), or Load + Loss of Import Capability (going from an N-1 Import Capability to an N-1-1 Import Capability; "Line-Line" scenario)
Import Limit =	Assumed transmission import limit
Assumed Unavailable Capacity =	Amount of assumed resource unavailability applied by de-rating capacity
Existing Resources =	Amount of Existing Capacity Resources within the Zone

Methodology for Calculating the TSA

The system conditions used for the TSA analysis within the FCM are documented in Section 6 of ISO New England Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity Market*.[23] For the calculation of ICR, LRA and TSA, the bulk of the assumptions are the same. However, due to the deterministic and

[22] A copy can be found at https://www.npcc.org/Standards/Directories/Directory%201%20-%20Design%20and%20Operation%20of%20the%20Bulk%20Power%20System%20%20Clean%20April%2020%202012%20GJD.pdf.
[23] Available at: http://www.iso-ne.com/rules_proceds/isone_plan/.

transmission security-oriented nature of the TSA, some of the assumptions for calculating the TSA requirement differ from the assumptions used in determining the LRA Requirement. The differences are as follows: the assumed loads for the TSA are the 90/10 peak loads for the Connecticut, Boston and combined SEMA and Rhode Island sub-areas[24] for the 2018/19 CCP, whereas for LRA calculations, a distribution of loads covering the range of possible peak loads for that CCP is used. In addition, for the TSA, the forced outage of fast-start (peaking) generation is based on an assumed value of 20% instead of being based on historical five-year average generating unit performance. Finally, the load and capacity relief obtainable from actions of ISO-NE OP-4, with the exception of Demand Resources (which are treated as capacity resources), is not assumed within TSA calculations.

Table 5 shows the details of the TSA requirement calculation for the Connecticut, NEMA/Boston, and SEMA/RI Capacity Zones.

Table 6: TSA Calculation Details (MW)

	Connecticut	NEMA/Boston	SEMA/RI
2014 Sub-area 90/10 Load*	8,415	6,835	6,465
Reserves (Largest unit or loss of import capability)	1,225	1,412	700
Sub-area Transmission Security Need	**9,640**	**8,247**	**7,165**
Sub-area Existing Resources	9,239	3,868	6,984
Assumed Unavailable Capacity	-808	-190	-723
Sub-area N-1 Import Limit	2,950	4,850	786
Sub-area Available Resources	**11,381**	**8,528**	**7,047**
TSA Requirement	= (9640-2950)/(1-808/9239)	(8247-4850)/(1-190/3868)	(7165-786)/(1-723/6984)
	= 7,331	**= 3,572**	**= 7,116**

Local Sourcing Requirement (LSR)

The LSR is determined as the higher of the LRA Requirement or TSA Requirement for the respective Capacity Zone. Table 7 summarizes the LRA and TSA for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones. As shown, the LRA is the highest requirement for the SEMA/RI Capacity Zone while the TSA is the highest requirement for the Connecticut and NEMA/Boston Capacity Zones. Therefore, the LSR for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones are 7,331 MW, 3,572 MW and 7,479 MW, respectively.

[24] The combined Connecticut, Southwest Connecticut and Norwalk sub-areas, the Boston sub-area, and the combined Southeastern Massachusetts and Rhode Island sub-area load forecast and resources are used as proxies for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones load forecast and resources since the transmission transfer capability of the interfaces used in the respective LSR calculations are determined based on the 13 sub-area system representations used within ISO-NE's Regional System Plan (RSP).

Table 7: LSR for the 2018/19 CCP (MW)

Capacity Zone	Transmission Security Analysis Requirements	Local Resource Adequacy Requirements	Local Sourcing Requirements
Connecticut	7,331	7,268	7,331
NEMA/Boston	3,572	3,129	3,572
SEMA/RI	7,116	7,479	7,479

Maximum Capacity Limit (MCL) Calculation

For the 2018/19 CCP, no zones were considered to be export-constrained; therefore an MCL was not filed for any Capacity Zones. An indicative MCL was calculated for the Maine Load Zone as part of the Capacity Zone Trigger Analysis, which determines if a Load Zone is either import or export-constrained and therefore modeled as a Capacity Zone in an FCA. This section of the Report details the calculation of the indicative MCL for the Maine Load Zone for the 2018/19 CCP.

To determine the MCL, the New England ICR and the LRA for the Rest of New England need to be identified. Given that the ICR is the total amount of resources that need to be procured within New England, and the LRA requirement for the Rest of New England is the minimum amount of resources required for that area to satisfy its reliability criterion; the difference between the two is the maximum amount of resources that can be purchased within an export-constrained Load Zone.

The indicative MCL for Maine includes qualified capacity resource imports over the New Brunswick ties (if relevant for a particular CCP) and also reflects the tie benefits assumed available over the New Brunswick ties. That is, the MCL is reduced to reflect the energy flows required to receive the assumed tie benefits from the Maritimes to assist the ISO-NE Balancing Authority Area at a time of a capacity shortage. Allowing more purchases of capacity from resources located in Maine could preclude the energy flows required to realize tie benefits.

For an export-constrained transmission Capacity Zone, the MCL is calculated using the following method as described in Market Rule 1, Section III.12.2.2:

a) Model the Capacity Zone under study and the *Rest of New England* area using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Balancing Authority area support from tie benefits.

b) If the system LOLE is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

c) Model the transmission interface constraint between the Capacity Zone under study and the *Rest of New England* area.

d) Add proxy units, if required, within the ISO-NE Balancing Authority Area to meet the resource adequacy planning criterion of once in 10 years of disconnection of non-interruptible customers. If the system LOLE with proxy units added is less than 0.1 days/year, firm load is added (or unforced capacity is subtracted) so that the system LOLE equals 0.1 days/year.

e) Adjust the firm load within the *Rest of New England* area until the LOLE of the *Rest of New England* area reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the *Rest of New England* area, an equal amount of firm load is removed from (or added to) the Capacity Zone under study.

The MCL is then calculated using the formula:

Figure 7: Formula for MCL Calculation

$$MCL_Y = Net\ ICR - LRA_{Rest\ of\ New\ England}$$

Where MCL_Y = Maximum Capacity Limit for Load Zone Y

Net ICR = MW of Net ICR

$LRA_{Rest\ of\ New\ England}$ = MW of Local Resource Adequacy Requirement for the *Rest of New England* area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Market Rule 1, Section III.12.2.1

Table 8 shows the details of the indicative MCL for the Maine Load Zone calculation for the 2018/19 CCP. This value was not filed with the FERC as part of the ICR Related Values as Maine was not determined to be a Capacity Zone.

Table 8: Indicative MCL for the Maine Load Zone Calculation Details (MW)

		2018/19 FCA
ICR for New England	[1]	34,189
$LRA_{RestofNewEngland}$	[2]	30,275
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,913**

Assumptions

Load Forecast

For each state in New England, ISO-NE develops a forecast distribution of typical daily peak loads for each week of the year based on each week's historical weather distribution combined with an econometrically estimated monthly model of typical daily peak demands. Each weekly distribution of typical daily peak demands includes the full range of daily peaks that could occur over the full range of weather experienced within that week along with their associated probabilities.

The load forecast models for each of the six New England states were estimated using thirteen years of historical weekday daily peaks, the weather conditions at the time of the daily peak, a seasonal relationship that captures the change in peak demand response to weather over time, and a seasonal relationship that captures the change in peak demand response to base energy demand (and therefore economic and demographic factors) over time. The weather response relationships are forecast to grow at their historical rates but are adjusted for expected changes in electric appliance saturations. The base load relationships are forecasted to grow at the same rate as the associated energy forecast. The weather is represented by over forty years of historically-based weekly regional weather. The energy forecast for each state is econometrically estimated using forecasts of the real price of electricity and either real income or real gross state product.

For purposes of determining the load forecast, ISO-NE Balancing Authority Area's load is defined as the sum of the load of each of the six New England states, calculated as described above. The forecasted load for the Connecticut Capacity Zone is the forecasted load for the state of Connecticut. The forecasted load for the NEMA/Boston Capacity Zone is developed using a load share ratio of the NEMA/Boston load to the forecasted load for the entire state of Massachusetts. The load share ratio is based on detailed bus load data from the network model for NEMA/Boston, as compared to the entire state of Massachusetts. The forecasted load for the SEMA portion of the SEMA/RI Capacity Zone is developed using the same load share ratio methodology as NEMA/Boston, while the RI portion is the load forecast for the state of Rhode Island.

The overall New England and individual sub-area load forecasts used in the calculation of ICR Related Values for the 2018/19 CCP are documented within the *2014 Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report)*.[25]

Load Forecast Uncertainty

GE MARS models the load forecast using hourly chronological sub-area loads and can include the effects of load forecast uncertainty by calculating the LOLE for up to ten different load levels and computes a weighted-average value based on the input

[25] Located on ISO-NE's website at: http://www.iso-ne.com/static-assets/documents/trans/celt/report/2014/2014_celt_report_rev.pdf.

probabilities. Load forecast uncertainty multipliers are then used to account for load uncertainty related to weather. These are the *"per unit"* multipliers used for computing the loads used to calculate the reliability indices. Each per unit multiplier represents a load level, which is assigned a probability of that load level occurring. The mean, or 1.0 multiplier, represents the 50/50 forecast for peak load. These uncertainty multipliers are allowed to vary by month.

The summer 2018 peak load forecast distribution is shown in Table 9. The values range from the 10^{th} percentile, representing peak loads with a 90% chance of being exceeded, to the 95^{th} percentile peak load, which represent peak loads having only a 5% chance of being exceeded. The median (50/50) of the forecast distribution is termed the *expected value* because the realized level is equally likely to fall either above or below that median value. The median value is reported to facilitate comparisons, but the inherently uncertain nature of the load forecast is modeled by the load forecast uncertainty multipliers used as an input to the GE MARS Model.

Table 9: Summer 2018 Peak Load Forecast Distribution (MW)

Year	10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
2018/19	29,045	29,275	29,510	29,935	30,005	30,310	30,860	31,310	32,430	33,120

Existing Capacity Resources

Market Rule 1, Section III.12.7.2 details what shall be modeled within the ICR Related Values calculations as capacity, as defined by the following:

(a) All Existing Generating Capacity Resources,

(b) Resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period,

(c) All Existing Import Capacity Resources backed by a multi-year contract(s) to provide capacity into the New England Balancing Authority area, where that multi-year contract requires delivery of capacity for the Commitment Period for which the Installed Capacity Requirement is being calculated, and

(d) Existing Demand Resources that are qualified to participate in the Forward Capacity Market and New Demand Resources that have cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period and Other Demand Resources in existence during the ICAP Transition Period.

Section III.12.7.2 also states that the rating of the Existing Generating Capacity Resources, Existing Demand Resources and Existing Import Capacity Resources used in the calculation of the ICR Related Values shall be the summer Qualified Capacity value of such resources for the relevant zone. The Qualified Capacity value is based on a five-year median capacity rating for each resource.

Summaries of resources categorized as Existing Capacity within the ICR Related Values calculations are provided in the sections below.[26] It should be noted that with the exception of Intermittent Power Resources (IPR), only summer capacity values are used within the calculation of the ICR Related Values.

For the 2018/19 CCP, a total of approximately 319 MW of resources were at risk of having their FCA Qualified Capacity administratively set by ISO-NE to the lesser of their summer or winter Qualified Capacity rating due to Market Rule III.13.1.2.2.5.2, which relates to an Existing Capacity resource which has a higher summer Qualified Capacity than winter Qualified Capacity. While resources in this situation had opportunities to mitigate this potential derating, ISO-NE did not know with certainty the exact amount of the administratively reduced capacity and therefore, these MWs were not removed from the model for the FCA9 ICR Related Values calculation.

For the 2018/19 FCA ICR Related Values calculations, there were a total of 32,842 MW of capacity resources modeled. These capacity resources are made up of generating, intermittent, demand and import resources along with a reduction in generating capacity to account for exports and de-ratings of import capacity. These resources are described in more detail in Table 10 – Table 15 of this report.

Generating Resources

Market Rule 1, Section III.13.1.2.2.1.1 states that the summer Qualified Capacity of a Generating Resource is calculated as the median of the most recent five summer Seasonal Claimed Capability (SCC) ratings with only positive, non-zero ratings included within the calculation. Generating resources, by Load Zone, used within the ICR Related Values calculations were based on Qualified Existing Generating Resources for the 2018/19 CCP at the time of the ICR calculation and are summarized in Table 10.

Table 10: Existing Qualified Generating Capacity by Load Zone (MW)

Load Zone	Summer
MAINE	2,888.145
NEW HAMPSHIRE	4,070.494
VERMONT	255.102
CONNECTICUT	8,255.015
RHODE ISLAND	1,861.432
SOUTH EAST MASSACHUSETTS	4,471.042
WEST CENTRAL MASSACHUSETTS	3,880.929
NORTH EAST MASSACHUSETTS & BOSTON	3,235.563
Total New England	**28,917.722**

[26] For detailed data on the Qualified Existing Resources that participated in the FCA9 see: http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-3_14_fca_9_info_filing_public_version.pdf.

Intermittent Power Resources

Section III.13.1.2.2.2 of Market Rule 1 discusses the rating methodology of resources considered Intermittent Power Resources (IPR). IPR are defined as wind, solar, run-of-river hydro-electric and other renewable resources that do not have direct control over their net power output.

Summer and winter capacities, by Load Zone, of existing IPR used within the ICR Related Values calculations were those that have Qualified as Existing Generating Resources for the 2018/19 CCP and are shown in Table 11.

Table 11: Existing IPR by Load Zone (MW)

Load Zone	Summer	Winter
MAINE	267.626	392.759
NEW HAMPSHIRE	167.628	222.733
VERMONT	79.038	121.579
CONNECTICUT	186.092	202.197
RHODE ISLAND	4.684	6.435
SOUTH EAST MASSACHUSETTS	75.866	77.907
WEST CENTRAL MASSACHUSETTS	59.642	93.077
NORTH EAST MASSACHUSETTS & BOSTON	70.231	72.023
Total New England	**910.807**	**1,188.710**

Demand Resources

To participate in the FCA as a Demand Resource, a resource must meet the definitions and requirements of Market Rule 1, Section III.13.1.4.1. Existing Demand Resources are subject to the same qualification process as Existing Generating Capacity Resources.

Market Rule 1, Section III.12.7.2 states that the rating of Demand Resources used within the calculation of the ICR Related Values shall be the summer Qualified Capacity value. The summer Qualified Capacity of a Demand Resource is rated based on Measurement and Verification analysis performed during the resource Qualification process.

Existing Demand Resources, by Load Zone, used within the ICR Related Values calculations are for the 2018/19 FCA are shown in Table 12. These values are the Existing Qualified values which also reflect the 8% Transmission and Distribution Gross-up applied to Demand Resources.

Table 12: Existing Demand Resources by Load Zone (MW)

Load Zone	On-Peak	Seasonal Peak	Real-Time Demand Response	Real-Time Emergency Gen	Total
MAINE	176.925	0.000	207.892	11.802	396.619
NEW HAMPSHIRE	94.951	0.000	18.707	14.022	127.680
VERMONT	125.420	0.000	37.007	2.866	165.293
CONNECTICUT	80.728	324.316	254.510	138.338	797.892
RHODE ISLAND	172.704	0.000	57.595	33.540	263.839
SOUTH EAST MASSACHUSETTS	252.710	0.000	38.785	15.962	307.457
WEST CENTRAL MASSACHUSETTS	260.352	52.968	91.799	27.798	432.917
NORTH EAST MASSACHUSETTS & BOSTON	486.312	0.000	50.189	26.099	562.600
Total New England	1,650.102	377.284	756.484	270.427	3,054.297

Import Resources

The Summer Qualified Capacity of an Existing Import Capacity Resource modeled within the ICR calculation follows Market Rule 1, Section III.13.1.3.3, which outlines the Qualification Process for Existing Import Capacity Resources.

The rating of imports used within the calculation of the ICR Related Values is the summer Qualified Capacity value, reduced by any submitted de-list bids reflecting the value of a firm contract(s) or any de-ratings due to Transmission Transfer Capability (TTC) limitations. If the overall amount of Existing Qualified Import Capacity over a transmission interface is greater than the transmission interface limit, the capacity of the import(s) being modeled within the ICR calculation is subsequently reduced to a value equal to that of the applicable transmission interface TTC. Table 13 shows the Existing Qualified Import Resources used within the ICR Related Values calculations for the 2018/19 CCP and the corresponding external transmission interface supplying the import capacity (MWs). There were no de-ratings of TTC for the Existing Qualified Import Capacity Resources for 2018/19 CCP. However; there was a 30 MW de-rating of generating capacity to reflect the value of the Vermont Joint Owners (VJO) contract.

Table 13: Existing Import Resources (MW)

Import Resource	Summer	External Interface
VJO - Highgate	6.000	Hydro-Quebec Highgate
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total MW	88.800	

Export Bids

An Export Bid is a Participant bid that may be submitted by certain resources in the FCA to export capacity to an external Balancing Authority area, as described in Section III.13.1.2.3.2.3 of Market Rule 1.

Market Rule 1 Section III.12.7.2 paragraph e) states that:

"…*capacity associated with Export Bids cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period*" shall be excluded from the ICR Related Values calculation.

Only one capacity export was modeled within the ICR Related Values calculation assumptions. This is the 100 MW sale of capacity to the Long Island Power Authority (LIPA) over the Cross-Sound Cable, which is modeled as a reduction in capacity from the unit-specific resource backing the export contract.

Table 14: Capacity Exports (MW)

Export	Summer
LIPA over Cross-Sound Cable	100.000

New Capacity Resources

Market Rule 1, Section III.12.7.2 describes the capacity resources that were modeled within the ICR calculations as the aggregate amount of Existing Generation Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources. Resource capacity that qualifies as a New Capacity Resource is not modeled within the ICR calculation.

Resources Used to Calculate Locational Requirements

The LRA and TSA values, used to determine the LSR for the import-constrained Connecticut, NEMA/Boston and SEMA/RI Capacity Zones are calculated with resource locations identified within the ISO-NE's Regional System Plan (RSP) sub-areas representing Connecticut, Boston and SEMA/RI combined, respectively. These resources are used as proxies for resources located within those Capacity Zones. This is done because the TTC calculated for the interfaces studied in the locational requirements analyses use the ISO-NE RSP sub-areas and are thus calculated for the RSP zones. For Demand Resources, the Existing Qualified Demand Resources for the Capacity Zone are used because the RSP values available would have to be estimated (particularly for the Passive Demand Resources) since actual locations for some of these resources are not currently available.

For the 2018/19 FCA ICR Related Values, there are no differences between the resources located within the corresponding RSP zones versus the resources located within the Connecticut, NEMA/Boston and combined SEMA/RI Capacity Zones. Table 15 shows the resources modeled in each of the Capacity Zones with a locational requirement along with the New England values.

Table 15: Resources Used in the LSR Calculations (MW)

Type of Resource	New England	Connecticut	NEMA/Boston	SEMA/RI
Generating Resources	28,787.722	8,255.015	3,235.563	6,332.474
Intermittent Power Resources	910.807	186.092	70.231	80.550
Passive Demand Resources	2,027.386	405.044	486.312	425.414
Active Demand Resources	1,026.911	392.848	76.288	145.882
Import Resources	88.800	-	-	-
Total MW Modeled	**32,841.626**	**9,238.999**	**3,868.394**	**6,984.320**

Transmission Transfer Capability

Market Rule 1, Section III.12.5 requires that ISO-NE update the transmission interface transfer capability for each internal and external transmission interface for the 2018/19 CCP, if necessary.[27] Although external transmission transfer capability is not used within the ICR calculation, they are used in the determination of tie benefits, including HQICCs, and will also be used within the FCA to limit the purchases of external installed capacity. Internal transmission transfer capability limits are used in the determination of any LSR and MCL values and tie benefit values.

External Transmission Transfer Capability

Table 16 shows the External TTC values that were used within the 2018/19 tie benefits study.

Table 16: Transmission Transfer Capability of New England External Interfaces Modeled in the Tie Benefits Study (MW)

External Interfaces Into New England	Summer TTC
Hydro-Quebec to New England via Phase II	1,400
Hydro-Quebec to New England via Highgate	200
New Brunswick to New England	700
New York to New England via New York AC Ties	1,400
New York to New England via Cross-Sound Cable DC Interface	0

External Transmission Interface Availability

The forced and scheduled outage rates of the transmission interfaces connecting ISO-NE to its neighboring Balancing Authorities are based on historical data provided by these Balancing Authorities. These values are shown in Table 17 and include the average forced outage rate (%) and maintenance outage rate (in weeks) as used in the models that

[27] For more detailed information on the RSP14 TTC analysis see a presentation from the March 17, 2014 Planning Advisory Committee (PAC) meeting: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf.

are associated with each external transmission interface. These assumptions were developed in 2011 and include data from the five-year period of 2006 through 2010.[28]

Table 17: External Interface Outage Rates (% and Weeks)

External Ties	Forced Outage Rate (%)	Maintenance (Weeks)
Hydro-Quebec Phase II	0.39	2.7
Highgate	0.07	1.3
New Brunswick Interface	0.08	0.4
New York AC Interface	0	0
Cross-Sound Cable	0.89	1.5

Internal Transmission Transfer Capability

For the 2018/19 FCA, ISO-NE evaluated three Capacity Zones relating to their LRA, using the zone under study and *Rest of New England* methodology. The first is the Connecticut Capacity Zone, which is modeled as import-constrained into Connecticut. The second is the NEMA/Boston Load Zone, which is modeled as import-constrained into NEMA/Boston. The third is the combined SEMA/RI Capacity Zone, which is modeled as import-constrained into SEMA/RI. In addition, the TSA analysis, which uses both the N-1 limit and the N-1-1 limit, was performed for these three Capacity Zones.[29]

Table 18 shows the N-1 and N-1-1 internal TTC for the Connecticut Import interface, Boston Import interface, and SEMA/RI Import interface used to calculate LSR within the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones, respectively. These TTC values are part of an annual study of transmission topology and are documented in the 2014 Regional System Plan (RSP14).

With the exception of the TTC values for the Connecticut, NEMA/Boston and SEMA/RI Capacity Zones which are modeled in the LSR calculations, remaining internal interfaces with a calculated TTC are modeled in the tie benefits study. For the 2018/19 CCP tie benefits study, these internal interfaces are documented as part of RSP14 and are available on slide 12 of a presentation given on March 17, 2014 to the Planning Advisory Committee (PAC):
http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/mar172014/a8_rsp14_transmission_interface_transfer_capabilities.pdf.

[28] For more detail on external tie availability assumptions see: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2011/jul152011/external_tie_outage_assumptions.pdf.

[29] The term N-1 represents the first contingency and the term N-1-1 represents the second contingency.

Table 18: Internal Transmission Transfer Capability Modeled in the LSR Calculations (MW)[30,31,32]

Interface		2018/19
Boston Import	N-1	4,850
	N-1-1	4,175
CT Import	N-1	2,950
	N-1-1	1,600
SEMA/RI Import	N-1	786
	N-1-1	473

OP-4 Load Relief

The New England resource planning reliability criterion requires that adequate capacity resources be planned and installed such that disconnection of firm load would not occur more often than once in 10 years due to a capacity deficiency, after taking into account the load and capacity relief obtainable from implementing Emergency Operating Procedures (EOPs). ISO New England Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP-4) is the EOP for New England. In other words, load and capacity relief assumed obtainable from implementing certain OP-4 actions are direct substitutes for capacity resources in meeting the once in 10 years disconnection of firm load criterion.

Under the FCM, the assumed emergency assistance (i.e. tie benefits) available from neighboring Balancing Authority areas, load reduction from implementation of 5% voltage reduction,[33] and capacity available from the dispatch of Real-Time Demand Resources[34] and Real-Time Emergency Generating Demand Resources[35] all constitute actions that ISO-NE System Operators can invoke under OP-4 to balance real-time system supply with demand (as applicable under both actual or forecast capacity shortage conditions). These actions are used as load and capacity relief assumptions within the development of the ICR Related Values.

[30] The Boston Import TTC shown in Table 18 includes the impact of the retirement of the Salem Harbor station and inclusion of the advanced NEMA/Boston transmission upgrades in the analysis. The proposed Footprint generating project was not included in the Boston Import interface import capability and will be evaluated at a future date.
[31] The Connecticut Import shown includes The New England East-West Solution (NEEWS), expected to be in-service by December 2015 and has been certified and accepted by ISO-NE to be included in FCA9 analyses.
[32] The Maine-New Hampshire interface TTC value of 1,900 MW was used in the indicative MCL analysis and Capacity Zone Trigger Analysis.
[33] Action 6 and 8 of OP4.
[34] Action 2 of OP4.
[35] Action 6 of OP4.

Tie Benefits

In the event of a capacity shortage in New England, tie benefits reflect the amount of emergency assistance that is assumed will be available to ISO-NE from its neighboring Balancing Authority areas, without jeopardizing system reliability in either the ISO-NE Balancing Authority area or its neighboring Balancing Authority areas. Tie Benefits are an input into the determination of the ICR Related Values, and in fact, displace the MW amount of resources that need to be purchased internal to New England within the FCA by an almost one to one ratio.

Tie Benefits Calculation Methodology

ISO-NE used the procedures for calculating tie benefits documented in Section III.12.9 of Market Rule 1. The tie benefits calculation methodology includes the calculation of tie benefits at the system-wide level and for each of the directly interconnected neighboring Balancing Authority areas of Québec, New Brunswick (Maritimes) and New York.

The tie benefits study for the 2018/19 CCP was conducted using the probabilistic GE MARS program to model projected system conditions for that timeframe. The methodology for calculating the total tie benefits, individual Balancing Authority tie benefits and the tie benefits assumed for individual interconnections is documented in more detail in Figure 8.

Figure 8: Summarization of the Tie Benefits Calculation Process[36]

- ***Process 1.0***
  - Calculate the tie benefits values for all possible interconnection states using isolated New England system as the reference
- ***Process 2.0***
  - Calculate initial total tie benefits for New England from all neighboring Balancing Authority Areas
- ***Process 3.0***
  - Calculate initial tie benefits for each individual neighboring Balancing Authority Area
  - Pro-rate tie benefits values of individual Balancing Authority Areas based on the total tie benefits, if necessary
- ***Process 4.0***
  - Calculate initial tie benefits for individual interconnection or group of interconnections
  - Pro-rate tie benefits values of individual interconnection or group of interconnections based on the individual Balancing Authority Area tie benefits, if necessary
- ***Process 5.0***
  - Adjust tie benefits of individual interconnection or group of interconnections to account for capacity imports
- ***Process 6.0***
  - Calculate the final tie benefits for each individual neighboring Balancing Authority Area
- ***Process 7.0***
  - Calculate the final total tie benefits for New England

Total Tie Benefits

Total tie benefits were calculated using the results of a probabilistic analysis that determines LOLE indices for the ISO-NE and neighboring Balancing Authority areas. The LOLE calculations were first done on an interconnected basis that included all existing connections (tie lines) between ISO-NE's directly connected neighboring Balancing Authority areas. This established the minimum amount of capacity that each area needs in order to comply with the NPCC resource adequacy requirements of 0.1 days per year LOLE.

These LOLE calculations were then repeated with ISO-NE isolated from all neighboring Balancing Authority areas. The tie benefits are then quantified by adding firm capacity resources within the isolated ISO-NE Balancing Authority area, until the LOLE is returned back to 0.1 days per year. The resources which were added to return ISO-NE to a LOLE of 0.1 days per year are called *"firm capacity equivalents"* and are assumed to be ISO-NE's total tie benefits.

Based on the methodology described above, a total of 1,970 MW of tie benefits are assumed within the ICR calculations for the 2018/19 CCP.

Individual Balancing Authority Area Tie Benefits

For calculating each Balancing Authority area's individual tie benefits, all the tie lines associated with the Balancing Authority area of interest are treated on an aggregate basis.

[36] A presentation on the 2018/19 Tie Benefits Study was reviewed at the RC on September 16, 2014 which provides more details on the calculation details and study assumptions and is available at http://www.iso-ne.com/static-assets/documents/2014/09/a6_fca9_tie_benefits_study.pdf.

The tie benefits from each Balancing Authority area are calculated for all possible interconnection states. The simple average of these tie benefits from each of these states will represent the calculated tie benefits from that specific Balancing Authority area.

If the sum of the Balancing Authority areas tie benefits is different from the total tie benefits for ISO-NE, then each Balancing Authority area's tie benefits are adjusted (up or down) based on the ratio of the individual Balancing Authority area tie benefits to the total tie benefits.

For the 2018/19 CCP, the individual Balancing Authority area tie benefits were calculated as 1,101 MW for Québec, 523 MW for the Maritimes, and 346 MW for New York.

Individual Tie (or Group of Ties) Tie Benefits

The tie benefits methodology calls for tie benefits to be calculated for an individual tie or group of ties to the extent that a discrete and material transfer capability can be identified for it. To calculate tie benefits for each tie or group of ties from the external Balancing Authority area of interest into ISO-NE, each is treated independently. The tie benefits for each individual tie or group of ties is calculated for all the interconnection states and the simple average of the tie benefits associated with these interconnections states is the resultant tie benefits for each tie or group of ties.

If the sum of the tie benefits from the individual tie or group of ties relative to their Balancing Authority area's total tie benefits are different, then the tie benefits of each individual tie or group of ties are adjusted (up or down) based on the ratio of the tie benefits of the individual tie or group of ties to the Balancing Authority area's total tie benefits.

For the 2018/19 CCP, individual interconnection tie benefits were determined from Québec over the HQ Phase II facility of 953 MW, 148 MW from Québec over the Highgate facility, 523 MW from the Maritimes over the New Brunswick interface and 346 MW of the New York tie benefits are delivered over the New York AC ties and 0 MW from the Cross-Sound Cable.

Hydro-Québec Interconnection Capability Credits (HQICCs)[37]

Hydro-Québec Interconnection Capability Credits, or HQICCs, are an allocation of the tie benefit over the Hydro-Québec Interconnection to the Interconnection Rights Holders (IHR), which are regional entities that hold certain contractual entitlements (i.e. rights) over this specific transmission interconnection. These rights are monetized as credits in the form of reduced capacity requirements.

[37] The 2018/19 CCP HQICCs values were filed with the Commission in the 2018/19 ICR filing: http://www.iso-ne.com/static-assets/documents/2014/11/er15-___-000_11-6-14_2018-2019_icr_filing.pdf.

The HQICC value is 953 MW, as determined by the tie benefits from Québec over the Phase II facility, and are applicable for every month during the 2018/19 CCP.

Adjustments to Tie Benefits

Processes 5.0 of the current tie benefits methodology requires that that individual interconnections or group of interconnections tie benefit values be adjusted, if necessary to account for the Existing Qualified Import Capacity Resources for 2018/19. If the sum of the tie benefits value and the import capacity is greater than the TTC of the individual interconnection or group of interconnections under study, then the tie benefits value will be reduced.

Process 6.0 of the tie benefits methodology determines the final tie benefits for each neighboring Balancing Authority Area as the sum of the tie benefits from the individual interconnections or groups of interconnections with that Balancing Authority Area, after accounting for any adjustment for capacity imports as determined within Process 5.0.

Final total tie benefits for the New England Balancing Authority Area from all neighboring Balancing Authority Areas is determined within Process 7.0 of the tie benefits methodology as the sum of these neighboring area tie benefits after accounting for any adjustment for capacity imports as determined within Process 6.0.

For the 2018/19 CCP, Table 19 shows the Existing Qualified Import Capacity Resources used to determine if adjustments of tie benefits are necessary as defined within Process 5.0 through Process 7.0 of the tie benefits methodology. For the 2018/19 Tie Benefits Study, no adjustment to tie benefits to account for capacity imports was necessary.

Table 19: Capacity Imports Used to Adjust Tie Benefits by External Interface (MW)

Import	New Brunswick	Hydro-Québec Phase II	Highgate	New York AC Ties
NYPA - CMR				68.8
NYPA - VT				14
VJO - Highgate			6	
Total			6	82.8

The results of the Tie Benefits Study for the 2018/19 CCP are summarized in Table 20.

Table 20: 2018/19 Tie Benefits (MW)

Balancing Authority Area	Summer	Winter
Québec via Phase II	953	953
Québec via Highgate	148	148
Maritimes	523	523
New York	346	346
Total Tie Benefits	1,970	1,970

Comparison of the 2018/19 and 2017/18 CCP's Tie Benefits

Table 21 gives a comparison of the 2018/19 CCP tie benefits calculated for FCA9 and the 2017/18 CCP tie benefits calculated for FCA8.

Table 21: 2018/19 versus 2017/18 Tie Benefits (MW)

Balancing Authority Area	2018/19 FCA9	2017/18 FCA8
Québec via Phase II	953	1,068
Québec via Highgate	148	83
Maritimes	523	492
New York	346	227
Total Tie Benefits	1,970	1,870

As the results show, the total tie benefits for the New England Balancing Authority Area has increased by 100 MW for the 2018/19 CCP versus the 2017/18 CCP. With the retirement of the Vermont Yankee nuclear generating station in the north and the Brayton Point generating station in the south, the North-South interface within New England has become even more constrained. The additional constraint of this transmission interface has shifted tie benefits from the northern side (Québec) to the southern side (New York) of the North-South transmission interface, which results in an increase in the tie benefit contributions from the New York over the New York AC ties and a subsequent decrease from Québec over the Phase II transmission interface.

5% Voltage Reduction

In addition to tie benefits, load reduction from implementation of a 5% voltage reduction is used in the development of the ICR Related Values. This constitutes an action that ISO-NE System Operators can invoke in real-time under ISO-NE OP-4, to balance system supply with demand under actual or expected capacity shortage conditions.

The amount of load relief assumed obtainable from invoking a 5% voltage reduction is based on the performance standard established within ISO New England's Operating Procedure No. 13, *Standards for Voltage Reduction and Load Shedding Capability*

("Operating Procedure No. 13" or OP13). ISO-NE Operating Procedure No. 13 requires that…

> *"…each Market Participant with control over transmission/distribution facilities must have the capability to reduce system load demand at the time a voltage reduction is initiated by at least one and one-half (1.5) percent through implementation of a voltage reduction."*

The calculation of the amount of 5% voltage reduction to be assumed within the ICR Related Values calculations uses the benchmark 1.5% value of load relief as specified in Appendix A of OP-4.[38] This benchmark reduction value is set based on the voltage reduction requirements of Operating Procedure No. 13, rather than the self-reported values submitted by Market Participants with control over transmission/distribution facilities.

For the 2018/19 ICR calculation, the methodology for calculating the amount of 5% voltage reduction assumed within the ICR remains the same as used in the prior year's ICR calculations. This methodology uses the 90/10 peak load forecast and assumes that all Demand Resources will have already been implemented, and thus, will have reduced the 90/10 load value at the time of peak or OP-4 invocation.

Thus the voltage reduction load relief values assumed as offsets against the ICR are calculated as the 1.5% voltage reduction assumption times the 90/10 peak load forecast after accounting for the amount of all Demand Resources (with the exception of limiting the amount of Real-Time Emergency Generation to 600 MW, the maximum amount purchased in the auction to meet the ICR, if necessary), which is assumed to be already implemented and therefore not contributing to the 1.5% reduction in load. Figure 9 shows this formula:

Figure 9: Formula for Calculating 5% Voltage Reduction Assumption

$$\lceil 90/10\, Peak\ Load\ MW - Demand\ Resource\ MW \rceil \times 1.5\%$$

Table 22 shows the amount of voltage reduction (MW) modeled as ISO-NE OP-4 load relief from Actions 6 & 8 for each of the months of the 2018/19 CCP within the ICR calculations.

[38] Appendix A of OP-4is available at: http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4a_rto_final.pdf.

Table 22: OP-4 Action 6 & 8 Modeled (MW)

	90/10 Peak Load	Passive Demand Resources	Real-Time Demand Resources	Real-Time Generating Resources	Action 6 & 8 5% Voltage Reduction
Jun 2018 - Sep 2018	32,430	2,027	756	270	441
Oct 2018 - May 2019	23,940	1,834	739	260	317

Operating Reserve

It is assumed that during peak load conditions, under extremely tight capacity situations, ISO-NE System Operations will maintain a minimum level of at least 200 MW of operating reserves for transmission system protection, prior to invoking manual load shedding procedures, if necessary. This pre-load shedding OP-4 situation is modeled as operating reserve within the ICR calculation by withholding this amount of capacity from serving regional peak load.

Proxy Units

Section III.12.7.1 of Market Rule 1 discusses the addition of proxy units to the ICR model. Proxy units are required when the available resources are insufficient for the unconstrained New England Balancing Authority area to meet the resource adequacy planning criterion specified in Section III.12.1. In the model, proxy units are used as additional capacity to determine the ICR, LRA, MCL and capacity requirement values for the Demand Curve.

The proxy units used in the ICR model reflect the resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in the New England Balancing Authority area, the reliability, or LOLE, of the New England Balancing Authority area does not change. The outage characteristics are the summer capacity weighted average availability of the resources in the New England Balancing Authority area as determined in accordance with Market Rule 1, Section III.12.7.3. The capacity of the proxy unit is determined by adjusting the capacity of the proxy unit until the LOLE of the New England Balancing Authority area is equal to the LOLE calculated while using the capacity assumptions described in Section III.12.7.2.

In May 2014, ISO-NE conducted a study to revise the proxy unit characteristics with the most recent system conditions in anticipation of requiring the use of proxy units within the FCA9 ICR model.[39] At the time of the study, the FCA8 (2017/18) ICR model was used as it was the most recent available ICR model.

[39] This study was presented to the PSPC on May 22, 2014 and is available at: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf.

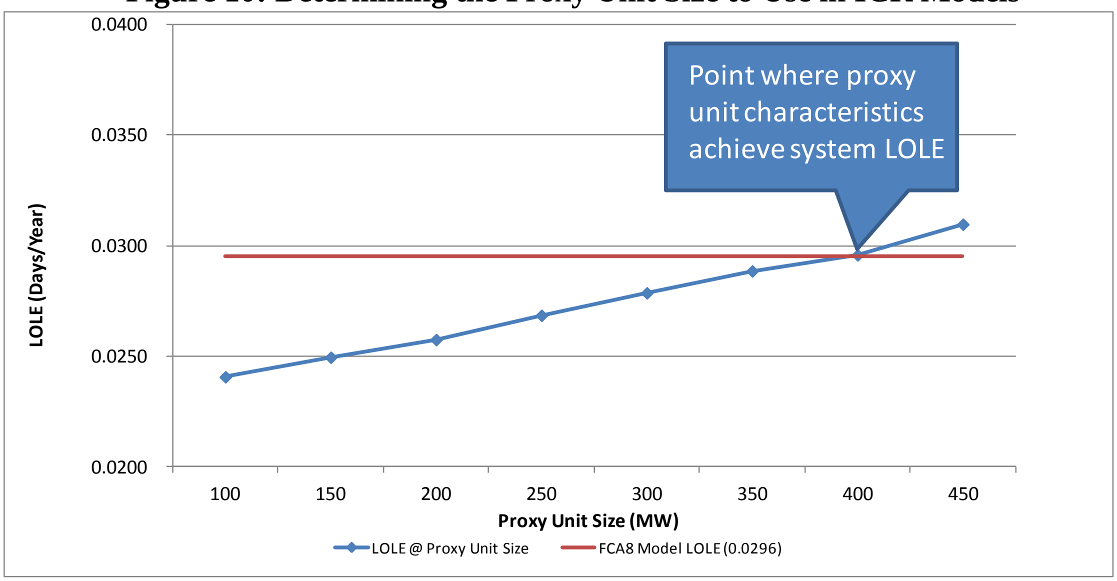
The procedure used to determine the new proxy unit size is to:

- Determine the initial LOLE of the system using the FCA8 ICR Model
- Determine the average availability of the system for both forced and scheduled outages (5.47% Forced Outage Rate (FOR) and 4 weeks of maintenance)
- Replace all resources in the system with proxy units with the average system availability
- Adjust the capacity ratings of the proxy units within the model until the initial system LOLE is achieved

Using the methodology above, the results showed that with the average system FOR of 5.47% and four weeks of maintenance for the FCA8 system, the appropriate size of the proxy units is 400 MW.

Figure 10 below, shows the point at which the LOLE of the model at various proxy unit sizes intersects the FCA8 existing system LOLE of 0.0296 days/year is 400 MW.

Figure 10: Determining the Proxy Unit Size to Use in ICR Models



Using the newly developed proxy unit size of 400 MW, four proxy units were needed for the 2018/19 ICR calculation, one proxy unit was needed in the model to calculate the capacity requirements for the Demand Curve at 1-in-5 LOLE and 11 proxy units were required to calculate the capacity requirements for the Demand Curve at 1-in-87 LOLE.

When modeling transmission constraints for the determination of LRA, the same proxy units may be added to the import-constrained zone (if needed), otherwise they will be added elsewhere in the rest of the New England Area. For the SEMA/RI LRA analysis, two proxy units needed to bring the New England system to the one day in ten years

LOLE reliability criteria were subsequently added to the SEMA/RI combined sub-area in order to calculate the SEMA/RI LRA.

Summary

Table 23 summarizes the capacity resources, proxy units and OP-4 assumptions used for the calculation of the 2018/19 ICR Related Values.

Table 23: Summary of Resource and OP-4 Assumptions (MW)

Type of Resource/OP-4	2018/19 FCA
Generating Resources	28,917.722
Intermittent Power Resources	910.807
Demand Resources	3,054.297
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(30.000)
OP-4 Voltage Reduction	441.000
Minimum Operating Reserve	(200.000)
Tie Benefits (Includes 953 MW of HQICCs)	1,970.000
Proxy Units	1,600.000
Total MW Modeled in ICR	**36,652.626**

Availability

Generating Resource Forced Outages

A five-year, historical average of unit-specific forced outage assumptions is determined for each generating unit that qualified as an Existing Generating Capacity Resource, using the most recent available data of monthly Equivalent Forced Outage Rate - Demand (EFORd) values from NERC's Generating Availability Data System (GADS).[40] The NERC GADS data, which is submitted by owners of regional generators to ISO-NE for the months of January 2009 through December 2013, was used to create an EFORd value for each generating unit that submits such data. The NERC Class Average data is used as a substitute for immature units and for units that are not required to submit NERC GADS data.

Table 24 shows the capacity-weighted, average EFORd values resulting from summing the individual generator data by generating resource category, weighted by individual capacity ratings. This is provided for informational purposes only. In the GE MARS model, the calculated EFORd for each generating resource is used as a generator-specific input assumption.

Generating Resource Scheduled Outages

A weekly representation of a generator's scheduled (maintenance) outages is another input assumption that goes into the GE MARS model. Included within the scheduled outages are annual maintenance outages and short-term outages, scheduled more than 14 days in advance of their outage date. A single value is then calculated for each generator, based on a five-year historical average. In addition to the EFORd data, Table 24 illustrates the average annual maintenance weeks assumed for each type of unit category, weighted by the summer capability. NERC Class Average data is used to calculate the average maintenance weeks assumption for immature units.

Table 24: Generating Resource EFORd (%) and Maintenance Weeks by Resource Category

Resource Category	Summer MW	Assumed Average EFORd (%) Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	12,523	3.6	5.8
Fossil	6,254	14.9	5.2
Nuclear	4,024	3.1	3.9
Hydro (Includes Pumped Storage)	2,931	4.6	6.5
Combustion Turbine	2,908	9.5	2.3
Diesel	193	6.5	1.0
Miscellaneous	86	14.2	1.8
Total System	28,918	6.7	5.1

[40] For more information on GADS, see the NERC website located at: http://www.nerc.com/pa/RAPA/gads/Pages/default.aspx.

Intermittent Power Resource Availability

The Qualified Capacity of an Intermittent Power Resource (IPR) is the resource's median output during "Reliability Hours," as averaged over a period of five years. Since this methodology takes into account the resources' historic availability as it applies to their FCM capacity ratings, these resources are assumed 100% available within the ICR model.

Demand Resources Availability

Passive Demand Resources

Table 25 tabulates the availability assumption of the Passive Demand Resources in the On-Peak and Seasonal Peak categories of Demand Resources. These resources are considered 100% available within the ICR model. These two categories consist of passive resources such as energy efficiency or conservation, which are considered always "*in service*" and as such, are subsequently assumed to be 100% available. The total average availability for all Passive Demand Resources is, therefore, 100%.

Table 25: Passive Demand Resources – Summer (MW) and Availability (%)

Load Zone	On-Peak		Seasonal Peak	
	Summer (MW)	Availability (%)	Summer (MW)	Availability (%)
MAINE	176.925	100	-	-
NEW HAMPSHIRE	94.951	100	-	-
VERMONT	125.420	100	-	-
CONNECTICUT	80.728	100	324.316	100
RHODE ISLAND	172.704	100	-	-
SOUTH EAST MASSACHUSETTS	252.710	100	-	-
WEST CENTRAL MASSACHUSETTS	260.352	100	52.968	100
NORTH EAST MASSACHUSETTS & BOSTON	486.312	100	-	-
Total New England	1,650.102	100	377.284	100

Active Demand Resources

The historical performance, from both audits and real time events, of Active Demand Resources (those in the Real-Time Demand Response and Real-Time Emergency Generators categories) are used to create the Active Demand availability assumption for use within the ICR calculation.[41]

For the calculation of ICR for the 2018/19 CCP, historical Demand Resource performance data for four years under FCM was used. This historical data consists of both OP-4 events and performance audits that occurred during the summer and winter of

[41] A detailed discussion of the Demand Resource availability assumption is available here: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/jun302014/2014_dr_availability.pdf.

2010 through 2013. At the June 24, 2014 PSPC meeting, ISO-NE proposed using an availability assumption for Active Demand Resources based on the summer and winter Active Demand performance data for the years 2010 through 2013, weighted by the capacity (MW) of the resources within each Load Zone for each year. After the presentation of this data to the PSCPC and subsequent stakeholder discussions, it was decided to use this proposal within the ICR Related Values calculations.

Table 26 shows the performance rates for Active Demand Resources applied to the Demand Resources by Load Zone and type of resource that are qualified as Existing Resources to participate in the 2018/19 FCA. This gives an average Active Demand Resource availability assumption of 88% for both Real-Time Demand Response and Real-Time Emergency Generators. The total average Demand Resource availability assumption for all Demand Resources, both Active and Passive, is 96%. This is an increase in performance of approximately 2% over prior values assumed within the 2017/18 ICR Related Values calculation, which used historical data from summer 2010 through 2012. In the ICR model, Demand Resources are modeled in blocks consisting of the type of Demand Resource by Load Zone. The overall availability is shown for informational purposes only.

Table 26: Demand Response Resources Summer (MW) and Availability (%)

Load Zone	Real-Time Demand Response		Real-Time Emergency Generators	
	Summer (MW)	Availability (%)	Summer (MW)	Availability (%)
MAINE	207.892	99	11.802	93
NEW HAMPSHIRE	18.707	88	14.022	99
VERMONT	37.007	92	2.866	82
CONNECTICUT	254.510	82	138.338	85
RHODE ISLAND	57.595	85	33.540	90
SOUTH EAST MASSACHUSETTS	38.785	84	15.962	84
WEST CENTRAL MASSACHUSETTS	91.799	89	27.798	89
NORTH EAST MASSACHUSETTS & BOSTON	50.189	81	26.099	89
Total New England	756.484	88	270.427	88

Difference from 2017/18 FCA ICR Related Values

Change in ICR

In an effort to quantify the effects that each input assumption has on the determination of ICR results, ISO-NE began with the input assumptions associated with the ICR calculated for the 2017/18 CCP and substituted each assumption individually with the corresponding 2018/19 CCP assumption. The net of these changes within the ICR value, as a result of each individual input assumption change, was then considered as the overall effect of the changed assumption set. Table 27 lists the assumptions for each CCP and their subsequent effect on the resultant ICR value. Note that the sum of the individual assumption effects on ICR do not necessarily sum to the total difference in ICR due to the interplay of the various assumptions within the model when they are modeled concurrently.

Table 27: Summary of ICR Input Assumptions for 2018/19 vs. 2017/18

Assumption	2018/2019 FCA		2017/2018 FCA		Effect on ICR (MW)
Tie Benefits & Updated External Interface Outage Assumptions	346 MW New York		227 MW New York		-213
	523 MW Maritimes		492 MW Maritimes		
	953 MW Quebec (HQICCs)		1068 MW Quebec (HQICCs)		
	148 MW Quebec via Highgate		83 MW Quebec via Highgate		
Total	1,970 MW		1,870 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	29,699	6.5%	32,098	5.8%	178
Demand Resources	3,054	4.0%	3,416	5.8%	-85
Imports	89	0.0%	89	0.0%	0
	MW		MW		
Load Forecast	30,005		29,790		348
	MW	%	MW	%	
OP 4 5%VR	441	1.50%	432	1.50%	-9
	MW		MW		
ICR	35,142		34,923		219

As shown in Table 27, there are several assumptions which have a notable effect on the ICR. The first is the increase in the load forecast for the 2018/19 CCP versus the 2017/18 CCP. While the 50/50 load forecast is shown for reference purposes, when calculating the ICR, a full distribution of possible peak loads is modeled along with moments of the distribution: the mean, standard deviation and 3rd cummulant which together form the load forecast uncertainty within the model. Other factors in addition to the load forecast uncertainty also can affect the amount of installed capacity needed to meet the load forecast, particularly the resource size and availabilities modeled. So while the annual increase in the 50/50 load forecast is 215 MW as shown, there is a decrease in the ALCC (amount of additional load) the system is able to support of 309 MW. This translates to the system requiring 348 MW of additional installed capacity to meet the load forecast in 2018/19 versus 2017/18.

The change in the tie benefits assumed for 2018/19 versus 2017/18 accounts for a decrease in ICR of 213 MW. The 100 MW increase in total tie benefits means that approximately 115 MW less installed capacity is needed within New England. Also, the decrease in HQICCs from 1,068 MW for 2017/18 to 953 MW for 2018/19 accounts for a decrease in ICR of 98 MW since HQICCs are added back into the ICR and are treated differently than other resources and are not adjusted by the ALCC amount.

The third assumption with a notable effect on ICR is the change in generating resource EFORd calculated for the 2018/19 ICR Related Values from those calculated for the 2017/18 ICR Related Values. As described in this Report's section on Resource Availability, the EFORd used in the ICR Related Values calculation is derived from the most recent five years of GADS data. The 5-year weighted average system-wide generator EFORd calculated for the 2018/19 ICR calculation is approximately 14% higher than the EFORd values calculated for the 2017/18 ICR calculation. This decrease in generating resource availability caused the ICR to increase by 178 MW because more resources are needed to meet the capacity requirements in New England if these resources are less reliable than in previous years.

Table 28 shows a comparison in the 2018/19 versus the 2017/18 CCP ICR calculation average EFORd by generator type.

Table 28: Assumed 5-Year Average % EFORd Weighted by Summer Ratings for 2018/19 versus 2017/18 ICR Calculations

Resource Category	2018/19 FCA9 5-year Average EFORd for the Years 2009-2013	2017/18 FCA8 5-year Average EFORd for the Years 2008-2012
Combined Cycle	3.6	3.9
Fossil	14.9	9.9
Nuclear	3.1	2.6
Hydro (Includes Pumped Storage)	4.6	5.1
Combustion Turbine	9.5	8.5
Diesel	6.5	7.8
Miscellaneous	14.2	15.8
Total System	6.7	5.9

The final assumption with a notable effect on the ICR is the change in Demand Resource type of resource and assumed availability. While the change in assumed availability for active Demand Resources did not vary greatly from the values used for the 2017/18 FCA ICR calculation, the increase in the amount of passive resources and corresponding decrease in active resources improved the overall Demand Resource availability assumption (calculated as 1 – DR Performance) from 5.8% to 4.0% therefore decreasing ICR by 85 MW in 2018/19 versus 2017/18. Table 29 below shows the breakdown by type of Demand Resource and corresponding performance for the 2018/19 versus 2017/18 ICR calculations.

Table 29: Comparison of Demand Resources (MW) & Performance (%) for 2018/19 versus 2017/18 ICR Calculations

Type of Demand Resource	2018/19 FCA9		2017/18 FCA8	
	MW	%	MW	%
Passive Demand Resources	2,027	100	1,769	100
Real-Time Demand Response	756	88	1,165	89
Real-Time Emergency Generators	270	88	483	86
Total Demand Resources	3,054	96	3,416	94

Change in LRA Requirement

Table 30 shows the difference in the assumptions and results of the 2018/19 LRA Requirement calculation, as compared to the 2017/18 LRA Requirement calculation for the import-constrained Connecticut and NEMA/Boston Load Zones Capacity Zones. A SEMA/RI locational capacity requirement was calculated for the first time for FCA9, therefore no comparisons are available.

Table 30: Summary of Changes in LRA Requirement for 2018/19 vs. 2017/18

		Connectiuct		NEMA/Boston	
Connecticut Zone		**2018/19 FCA9**	**2017/18 FCA8**	**2018/19 FCA9**	**2017/18 FCA8**
$Resource_z$	[1]	9,239	9,768	3,868	3,685
$Proxy\ Units_z$	[2]	0	0	0	0
$Firm\ Load\ Adjustment_z$	[3]	1,825	2,282	775	685
FOR_z	[4]	0.074	0.068	0.042	0.044
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**7,268**	**7,319**	**3,129**	**2,968**

Change in TSA Requirement

Table 31 shows the difference in the assumptions and results of the 2018/19 TSA Requirement calculation, as compared to the 2017/18 TSA Requirement calculations for the import-constrained Connecticut and NEMA/Boston Load Zones. As noted above, there is no comparison available for the SEMA/RI Capacity Zone TSA since FCA9 is the first time a TSA Requirement was calculated.

Table 31: Comparison of the TSA Requirement Calculation for 2018/19 vs. 2017/18 (MW)[42]

	Connecticut		NEMA/Boston	
	2018/19 FCA9	2017/18 FCA8	2018/19 FCA9	2017/18 FCA8
Sub-area 90/10 Load	8,415	8,330	6,835	6,745
Reserves (Largest unit or loss of import capability)	1,225	1,200	1,412	1,395
Sub-area Transmission Security Need	**9,640**	**9,530**	**8,247**	**8,140**
Existing Resources	9,239	9,768	3,868	3,685
Assumed Unavailable Capacity	-808	-729	-190	-149
Sub-area N-1 Import Limit	2,950	2,800	4,850	4,850
Sub-area Available Resources	**11,381**	**11,839**	**8,528**	**8,386**
TSA Requirement	**7,331**	**7,273**	**3,572**	**3,428**

Connecticut

The Connecticut LRA decreased for 2018/19 versus the 2017/18 CCP calculation. The primary reason for the decrease in the Connecticut LRA for the 2018/19 CCP versus the 2017/18 CCP is the increase in the N-1 TTC for the Connecticut Import interface that was used to calculate the Connecticut LRA Requirement. The N-1 TTC increased from 2,800 MW to 2,950 MW. This increase in the Connecticut Import TTC is due to transmission upgrades associated with the New England East-West Solution (NEEWS) which is expected to be in-service by December 2015 and has been certified and accepted by ISO-NE to be included in FCA9 analyses. The increase in TTC within the probabilistic LRA analysis translates to an almost one to one MW decrease in the LRA Requirement without considering any other assumption changes.

The Connecticut TSA increased for the 2018/19 CCP versus the 2017/18 CCP. While the increase in the Connecticut Import N-1 and N-1-1 TTC does act to decrease the TTC, other factors such as an increase in the rating of the largest generator used as reserves in the calculation from 1,200 to 1,225 MW, an increase in the 90/10 load forecast of 84 MW and an increase in the amount of unavailable resource MWs of 79 MW (approximately 10%) were enough to offset the increase in TTC and subsequently increase the TSA for Connecticut by 58 MW (less than 1%).

NEMA/Boston

The increase in the NEMA/BOSTON LRA and TSA Requirements for the 2018/19 CCP is primarily due to an increase in the load forecast for the NEMA/Boston sub-area.

[42] The 90/10 load for Connecticut and NEMA/Boston shown are the sub-area loads. The LRA and TSA analyses are preformed on a sub-area basis which is used as proxies for the load zones. This is done because the transmission transfer capabilities are calculated using a sub-area analysis only.

Table 32 shows the summary comparison between the all the ICR Related Values and their inputs calculated for the 2018/19 FCA versus the 2017/18 FCA.

Table 32: Comparison of all ICR Related Values (MW)[43]

	New England		Connecticut		NEMA/Boston		SEMA/RI	
	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA
Peak Load (50/50)	30,005	29,790	7,725	7,650	6,350	6,260	5,910	-
Existing Capacity Resources*	32,842	35,443	9,239	9,768	3,868	3,685	6,984	-
Installed Capacity Requirement	35,142	34,923						
NET ICR (ICR Minus HQICCs)	34,189	33,855						
1-in-5 LOLE Demand Curve capacity value	33,132	-						
1-in-87 LOLE Demand Curve capacity value	37,027	-						
Local Resource Adequacy Requirement			7,268	7,319	3,129	2,968	7,479	-
Transmission Security Requirement			7,331	7,273	3,572	3,428	7,116	-
Local Sourcing Requirement			7,331	7,319	3,572	3,428	7,479	-

[43] Existing Capacity Resources value for New England excludes HQICCs.

{ End of Report }