ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2017/18 Capacity Commitment Period

ISO New England Inc.
January 2014

ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2017/18 Capacity Commitment Period

Executive Summary

As part of the Forward Capacity Market (FCM), ISO New England Inc. (ISO-NE) is preparing to conduct the Forward Capacity Auction (FCA) for the 2017/18 Capacity Commitment Period (CCP). The auction, which will be conducted on February 3, 2014, is intended to result in capacity (megawatts) commitments of sufficient quantities to meet the Installed Capacity Requirement (ICR) for the 2017/18 CCP. The 2017/18 CCP is the eighth CCP of the FCM and it begins on June 1, 2017 and ends on May 31, 2018.

In this report, ISO-NE documents the assumptions and results of the 2017/18 CCP ICR, Local Sourcing Requirements (LSR) and Maximum Capacity Limit (MCL) calculations – (collectively referred to as the "ICR-Related Values"), all of which are key inputs in the FCA, along with the Hydro-Québec Interconnection Capability Credits (HQICCs), which are also a key input into the calculation of the ICR.

As detailed below, ISO-NE proposes an ICR of 34,923 MW. This value accounts for tie benefits (emergency energy assistance) assumed obtainable from New Brunswick (Maritimes), New York and Québec of 1,870 MW, but it does not reflect a reduction in capacity requirements relating to HQICCs. The HQICC value of 1,068 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 1,068 MW per month,[1] is 33,855 MW.[2]

The FCA process requires the modeling of certain transmission constraints, including LSR and MCL for Load Zones that may be import- or export-constrained. LSR for the Connecticut and Northeast Massachusetts/Boston ("NEMA/Boston") Load Zones are 7,319 MW and 3,428 MW, respectively. The MCL for the Maine export-constrained Load Zone is 3,960 MW.[3]

As in past years, ISO-NE developed the initial ICR recommendation along 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

[1] HQICCs are monthly values.
[2] Prepared Joint Testimony of Mr. Mark G. Karl and Mr. Peter K. Wong on Behalf of ISO New England Inc. ("Karl-Wong Testimony") (Attachment 1) at p. 10.
[3] The Local Sourcing Requirement and Maximum Capacity Limit values are used to determine whether separate zones must be modeled in the eighth Forward Capacity Auction. The determinations regarding separate zones are being provided in a contemporaneous filing regarding numerous inputs into the Forward Capacity Auction as required by Section III.13.8.1 of the ISO Tariff. *See ISO New England Inc., Informational Filing for Qualification in the Forward Capacity Market*, Docket No. ER14-328-000 (filed concurrently on November 5, 2013) ("FCA 8 Informational Filing"), Transmittal Letter at p. 4.

course of four meetings, by the NEPOOL Reliability Committee (RC) at its September 18, 2013 meeting and by the NEPOOL Participants Committee (PC) at its October 4, 2013 meeting.[4] In addition, in 2007 the New England States Committee on Electricity (NESCOE) was formed.[5] Among other responsibilities, NESCOE is responsible for providing feedback on the proposed ICR-Related Values at the relevant NEPOOL Reliability Committee and Participants Committee meetings, and was in attendance for the meetings at which the ICR-Related Values for the 2017/2018 Forward Capacity Auction were discussed.

After the NEPOOL committee voting process was completed, ISO-NE filed the ICR-Related Values and HQICCs for the 2017/18 Forward Capacity Auction with the FERC in a filing dated November 5, 2013.[6] The FERC accepted the ICR-Related Values in a letter dated December 30, 2013.[7]

Table 1 shows the ICR-Related Values for the 2017/18 CCP. The monthly values for the HQICCs are provided in Table 2.

---

[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. The NEPOOL Load Forecast Committee ("LFC"), also a subcommittee of the NEPOOL Reliability Committee, reviews the load forecast assumptions and methodology.

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

[6] The ISO-NE filing is located at http://www.iso-ne.com/regulatory/ferc/filings/2013/nov/er14-328-000_11-5-13__icr_2017-2018_.pdf.

[7] The FERC Order accepting the ICR Values for the 2017/18 FCA is available at: http://www.iso-ne.com/regulatory/ferc/orders/2013/dec/er14-328-000_12-30-13_ltr_ord_accept_hqicc_icr_values.pdf.

Table 1: Summary of 2017/18 ICR-Related Values (MW)[8,9]

	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	29,790	7,650	6,260	2,115
Total Resources	35,443	9,768	3,685	3,593
Installed Capacity Requirement	34,923			
NET ICR (ICR Minus 1,068 MW HQICCs)	33,855			
Local Sourcing Requirement		7,319	3,428	
Maximum Capacity Limit				3,960

Table 2: Monthly HQICCs (MW)

2017/18 Capacity Commitment Period Month	HQICC Values
June	1,068
July	1,068
August	1,068
September	1,068
October	1,068
November	1,068
December	1,068
January	1,068
February	1,068
March	1,068
April	1,068
May	1,068

[8] After reflecting a reduction in capacity requirements relating to the 1,068 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 33,855 MW.
[9] Total Resources value for New England excludes HQICCs.

Table of Contents

Executive Summary 1
Table of Contents 4
List of Tables 5
List of Figures 7
Introduction 8
Summary of ICR-Related Values and Components for 2017/18 9
Stakeholder Process 10
Methodology 11
  Reliability Planning Model for ICR-Related Values 11
  Installed Capacity Requirement (ICR) Calculation 12
  Local Sourcing Requirements (LSR) Calculation 13
Local Resource Adequacy (LRA) Requirement 13
  Transmission Security Analysis (TSA) Calculation 16
  Methodology for Calculating the TSA 17
  Local Sourcing Requirement (LSR) 18
  Maximum Capacity Limit (MCL) Calculation 18
Assumptions 20
Load Forecast 20
  Load Forecast Uncertainty 21
Existing Capacity Resources 21
  Generating Resources 22
  Intermittent Power Resources 23
  Demand Resources 23
  Import Resources 24
Export Bids 24
New Capacity Resources 25
Resources Used to Calculate Locational Requirements 25
Transmission Transfer Capability 26
  External Transmission Transfer Capability 26
  External Transmission Interface Availability 26
  Internal Transmission Transfer Capability 27
OP-4 Load Relief 28
  Tie Benefits 28
  5% Voltage Reduction 33
Operating Reserve 35
Availability 36
  Generating Resource Forced Outages 36
  Generating Resource Scheduled Outages 36
  Intermittent Power Resource Availability 37
  Demand Resources Availability 37
Difference from 2016/17 FCA ICR-Related Values 39

List of Tables

Table 1: Summary of 2017/18 ICR-Related Values (MW) 3
Table 2: Monthly HQICCs (MW) 3
Table 3: ICR-Related Values and Components for 2017/18 (MW) 9
Table 4: Variables Used to Calculate ICR (MW) 13
Table 5: LRA Requirement Calculation Details (MW) 16
Table 6: TSA Calculation Details (MW) 18
Table 7: LSR for the 2017/18 CCP (MW) 18
Table 8: MCL Calculation Details (MW) 20
Table 9: Summer 2017 Peak Load Forecast Distribution (MW) 21
Table 10: Existing Qualified Generating Capacity by Load Zone (MW) 22
Table 11: Existing IPR by Load Zone (MW) 23
Table 12: Existing Demand Resources by Load Zone (MW) 24
Table 13: Existing Import Resources (MW) 24
Table 14: Capacity Exports (MW) 25
Table 15: Resources Used in the LSR & MCL Calculations (MW) 26
Table 16: Transmission Transfer Capability of New England External Interfaces Modeled in the Tie Benefits Study (MW) 26
Table 17: External Interface Outage Rates (% and Weeks) 27
Table 18: Internal Transmission Transfer Capability Modeled in the LSR and MCL Calculations (MW)" 28
Table 19: Capacity Imports Used to Adjust Tie Benefits (MW) 32
Table 20: 2017/18 Tie Benefits (MW) 33
Table 21: 2017/18 versus 2016/17 Tie Benefits (MW) 33
Table 22: OP-4 Action 6 & 8 Modeled (MW) 35
Table 23: Summary of Resource and OP-4 Assumptions (MW) 35
Table 24: Generating Resource EFORd (%) and Maintenance Weeks by Resource Category 37
Table 25: Passive Demand Resources – Summer (MW) and Availability (%) 38
Table 26: Demand Response Resources Summer (MW) and Availability (%) 39
Table 27: Summary of ICR Input Assumptions for 2017/18 vs. 2016/17 40
Table 28: Assumed 5-Year Average % EFORd Weighted by Summer Ratings for 2017/18 versus 2016/17 ICR Calculations 40
Table 29: Increase in 5-year Average EFORd for FCA8 Vs. FCA7 (%) 42
Table 30: 2013 CELT vs. 2012 CELT 2017/18 CCP Weekly Load Forecast Mean (MW) 43
Table 31: 2013 CELT vs. 2012 CELT 2017/18 CCP Weekly Load Forecast Standard Deviation 44
Table 32: 2013 CELT vs. 2012 CELT 2017/18 CCP Weekly Load Forecast Third Cumulant 44
Table 33: Summary of Changes in LRA Requirement for 2017/18 vs. 2016/17 45
Table 34: Comparison of the TSA Requirement Calculation for 2017/18 vs. 2016/17 (MW) 45
Table 35: Distribution of the 2013 CELT Load Forecast to the RSP Sub-areas 46

Table 36: Changes to the Boston Sub-area Load – 2013 CELT Vs. 2012 CELT (%) 47
Table 37: Comparison of MCL Calculation for 2017/18 vs. 2016/17 for Maine (MW) .. 47
Table 38: Comparison of all ICR-Related Values (MW) 48

List of Figures

Figure 1: Formula for Annual Resulting Reserve Margin (%) 9
Figure 2: Formula for ICR Calculation.. 12
Figure 3: Formula for LRA Calculation 15
Figure 4: Surplus Capacity Adjustment in *Rest of New England* 15
Figure 5: Formula for TSA Requirements.. 17
Figure 6: Formula for MCL Calculation... 19
Figure 7: Summarization of the Tie Benefits Calculation Process 30
Figure 8: Formula for Calculating 5% Voltage Reduction Assumption........................... 34

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[10], with respect to satisfying the peak demand forecast for the New England Balancing Authority area while maintaining the 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).[11]

This report discusses the derivation of the ICR, Local Sourcing Requirements (LSR) and Maximum Capacity Limits (MCL) (collectively, the "ICR-Related Values"), along with the Hydro-Québec Interconnection Capability Credits (HQICCs) for the 2017/18 CCP's Forward Capacity Auction (FCA) to be conducted on February 3, 2014. The 2017/18 CCP starts on June 1, 2017 and ends on May 31, 2018.

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, and transmission interface transfer capabilities. Also discussed are the calculation of LSR for import-constrained Load Zones, including the Transmission Security Analysis (TSA) Requirements and Local Resource Adequacy (LRA) Requirements that are inputs into the calculation of LSR and the calculation of the MCL for export-constrained Load Zones. In general, the methodology used for calculating the ICR-Related Values for the 2017/18 FCA remains unchanged from the methodology used for calculating the prior ICR-Related Values for the 2016/17 FCA.

[10] Information on the NPCC Standards is available at: https://www.npcc.org/Standards/default.aspx.
[11] ISO-NE OP-4 is located at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html.

Summary of ICR-Related Values and Components for 2017/18

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

Table 3: ICR-Related Values and Components for 2017/18 (MW)[12]

	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	29,790	7,650	6,260	2,115
Total Resources	35,443	9,768	3,685	3,593
Installed Capacity Requirement	34,923			
NET ICR (ICR Minus 1,068 MW HQICCs)	33,855			
Local Sourcing Requirement		7,319	3,428	
Maximum Capacity Limit				3,960

The 34,923 MW Installed Capacity Requirement 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 1,068 MW, the net Installed Capacity Requirement for use in the 2017/18 FCA is 33,855 MW, which is described as the "*Net ICR*".

The 33,855 MW of Net ICR, which excludes HQICCs, results in an Annual Resulting Reserve Margin value of 13.6%. 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 13.6% Annual Resulting Reserving Margin is an increase from the 12.1% value calculated for the 2016/17 FCA. The increase in the percent reserve margin can be attributed to an increase in the generator forced outage rates and an increase in load forecast uncertainty. The increase in generator unavailability and the increase in load forecast uncertainty, along with the overall change in ICR, is discussed in more detail in the last section of this report, *Difference from the 2016/17 FCA ICR-Related Values*.

[12] Total Resource value for New England excludes HQICCs.

Stakeholder Process

As in past years, ISO-NE developed the initial ICR recommendation along with stakeholder input, which was provided in part through the NEPOOL committee processes 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 under 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 and MCL, 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 18, 2013 meeting and acted on by the NEPOOL Participants Committee (PC) at its October 4, 2013 meeting.[13] In addition, in 2007 the New England States Committee on Electricity ("NESCOE") was formed.[14] Among other responsibilities, NESCOE is responsible for providing feedback on the proposed ICR-Related Values at the relevant NEPOOL PSPC, RC and PC meetings, and was in attendance for the meetings at which the ICR-Related Values for the 2017/18 Forward Capacity Auction were discussed.[15]

At the September 18, 2013 meeting of the RC, a motion to recommend support the ICR-Related Values passed by a show of hands, with three opposed and nine abstentions. A motion that the RC recommend that the PC support the HQICC values passed by a show of hands, with two opposed and no abstentions. At its October 4, 2013 meeting, the PC voted to support the ICR-Related Values and HQICC Values as part of its Consent Agenda.[16]

ISO-NE subsequently filed the ICR-Related Values and HQICCs for the 2017/18 FCA with the FERC on November 5, 2013.[17] The FERC accepted the ICR-Related Values in a letter dated December 30, 2013.[18]

---

[13] 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 NEPOOLRC, reviews the load forecast assumptions and methodology.

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

[15] *See* the NESCOE Funding Filing at p. 14.

[16] The Consent Agenda for a PC meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the PC) to be taken by the PC through approval of a single motion at a meeting. All recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The PC's approval of the October 4, 2013 Consent Agenda included its support for the ICR-Related Values and the HQICC values.

[17] A copy of the filing is available at: http://www.iso-ne.com/regulatory/ferc/filings/2013/nov/er14-328-000_11-5-13__icr_2017-2018_.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 2017/18 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

---

[18] The FERC Order accepting the ICR Values for the 2017/18 FCA is available at: http://www.iso-ne.com/regulatory/ferc/orders/2013/dec/er14-328-000_12-30-13_ltr_ord_accept_hqicc_icr_values.pdf.

[19] Available at: http://www.iso-ne.com/rules_proceds/isone_plan/

Carlo process repeatedly simulates the year using multiple replications and evaluates the impacts of a wide-range of possible random combinations of resource outages. Chronological system histories are developed by combining randomly generated operating histories of the resources serving the hourly chronological demands. 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 2: 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 Hydro-Québec Interconnection Capability Credits

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 actual system, as modeled, is more reliable than the resource adequacy criterion, an adjustment is made in the amount of capacity needed or additional load required to attain the resource adequacy criterion. If the system is more reliable than the resource adequacy criterion (i.e., the system LOLE is less than or equal to 0.1 days per year), additional resources are not required, and the ICR is determined by increasing loads (*Additional Load Carrying Capability* or ALCC) so that New England's LOLE is exactly at 0.1 days per year. For the 2017/18 CCP, the New England system using the resources that qualified as Existing Capacity, is more reliable than the resource adequacy criterion requires. This results in a positive value for the ALCC. Therefore, no adjustments of additional capacity in the form of proxy units were required to be added to the model.[20] In the ICR calculation, the HQICCs are treated differently than other resources; they are not adjusted by the ALCC amount. Table 4 shows the details of the variables used to calculate the ICR for the 2017/18 CCP.

Table 4: Variables Used to Calculate ICR (MW)

Installed Capacity Requirement Calculation Details	2017/18 FCA
Annual Peak	29,790
Total Capacity	37,545
Tie Benefits	1,870
HQICCs	1,068
OP4 - Action 6 & 8 (Voltage Reduction)	432
Minimum Reserve Requirement	(200)
ALCC	1,398
Installed Capacity Requirement	34,923
Net ICR	33,855

Local Sourcing Requirements (LSR) Calculation

The methodology for calculating LSR for import-constrained Load Zones involves calculating the amount of resources located within the Load Zone that would meet both a local resource adequacy criteria called the Local Resource Adequacy (LRA) Requirement and a transmission security criterion called the Transmission Security Analysis (TSA) Requirement. The TSA Requirement is a tool that ISO-NE uses to maintain system operational reliability when reviewing de-list bids of resources within the FCM auctions.[21] 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

[20] 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 LOLE is unchanged. The use of proxy units to meet the system LOLE criterion is intended to neutralize the size and availability impact of unknown resource additions on the ICR.

[21] ISO Tariff revisions filed with the FERC on February 22, 2010 in Docket No. ER10-787-000

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. If a zone has insufficient capacity, capacity would be shifted into that zone. 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, plus proxy units in the zone, minus the unavailability-adjusted, load-shift amount.

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 Load 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 Load Zone, the LRA Requirement is calculated using the following methodology, as outlined in Market Rule 1, Section III.12.2.1:

a) Model the Load 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 Load 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 Load 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 3: Formula for LRA Calculation

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

Where	LRA_z	= Local Resource Adequacy Requirement for Load 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 Load Zone Z.
	$Proxy\ Units\ Adjustment_z$	= MW of firm load added to (or unforced capacity subtracted from) Load Zone Z until the system LOLE equals 0.1 days/year.
	$Firm\ Load\ Adjustment_z$	= MW of firm load added within Load 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 Load Zone Z, including any proxy unit additions to Load Zone Z.

In addition, when performing the LRA calculation for the *Rest of New England* area, 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 4: 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 Load 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 2017/18 CCP. The LRA Requirement for the *Rest of New England* is used in the calculation of Maine MCL. *Rest of New England* refers to all Load Zones with the exception of the Load Zone under study.

Table 5: LRA Requirement Calculation Details (MW)

		Connecticut	NEMA/Boston	Rest of New England
$Resource_z$	[1]	9,768	3,685	31,850
$Proxy\ Units_z$	[2]	0	0	0
$Proxy\ Units\ Adjustment_z$	[3]	0	0	1,570
$Firm\ Load\ Adjustment_z$	[4]	2,282	685	268
FOR_z	[5]	0.0682	0.0442	0.0605
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**7,319**	**2,968**	**29,894**

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, this 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 Load 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 5 shows the formula used in the calculation of TSA requirements.

[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.

Figure 5: 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 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 and Boston sub-areas[24] for the 2017/18 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 and NEMA/Boston Load Zones.

[23] Available at: http://www.iso-ne.com/rules_proceds/isone_plan/.

[24] The combined Connecticut, Southwest Connecticut and Norwalk sub-areas and the Boston sub-area load forecast and resources are used as proxies for the Connecticut and NEMA/Boston Load 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 6: TSA Calculation Details (MW)

	Connecticut	NEMA/Boston
Sub-area 2017 90/10 Load	8,330	6,745
Reserves (Largest unit or loss of import capability)	1,200	1,393
Sub-area Transmission Security Need	**9,530**	**8,140**
Sub-area Existing Resources	9,768	3,685
Assumed Unavailable Capacity	-729	-149
Sub-area N-1 Import Limit	2,800	4,850
Sub-area Available Resources	**11,839**	**8,386**
TSA Requirements	=(9530-2800)/(1-729/9768)	=(8140-4850)/(1-149/3685)
	=7,273	**=3,428**

Local Sourcing Requirement (LSR)

The LSR for the Connecticut and NEMA/Boston Load Zone is the higher of the LRA Requirement or TSA Requirement for the respective Load Zone. Table 7 summarizes the LRA and TSA for the Connecticut and NEMA/Boston Load Zones. As shown, the LRA is the highest requirement for the Connecticut Load Zone while the TSA is the highest requirement for the NEMA/Boston Load Zone. Therefore, the LSR for the Connecticut and NEMA/Boston Load Zones are 7,319 MW and 3,428 MW, respectively.

Table 7: LSR for the 2017/18 CCP (MW)

Load Zone	Local Resource Adequacy Requirement	Transmission Security Analysis Requirement	Local Sourcing Requirement
Connecticut	7,319	7,273	7,319
NEMA/Boston	2,968	3,428	3,428

Maximum Capacity Limit (MCL) Calculation

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 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 the export-constrained Maine transmission Load Zone[25], the MCL is calculated using the following method as described in Market Rule 1, Section III.12.2.2:

a) Model the Load 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* 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 Load Zone under study.

The MCL is then calculated using the formula:

Figure 6: Formula for MCL Calculation

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

Where	MCL_Y	= Maximum Capacity Limit for Load Zone Y
	ICR	= MW of Net ICR
	$LRA_{\text{Rest of New England}}$	= 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

[25] The load forecast and resources of the combined Maine, Bangor Hydro-Electric and Southern Maine sub-areas are used as a proxy for the Maine Load Zone since the transmission transfer capability of the interface used in the Maine MCL calculation is determined based on the 13 sub-area model within the ISO-NE Regional System Plan (RSP).

Table 8 shows the details of the MCL calculation for the 2017/18 CCP.

Table 8: MCL Calculation Details (MW)

		Maine
ICR for New England	[1]	33,855
$LRA_{RestofNewEngland}$	[2]	29,894
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,960**

Assumptions

Load Forecast

ISO-NE develops, for each state, 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 twelve 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 demand 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 loads for the Connecticut and Maine Load Zones are the forecasted loads for the states of Connecticut and Maine.[26] The forecasted load for the NEMA/Boston Load 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.

[26] Maine load and capacity excludes the Northern Maine service territory of Maine Public Service (MPS) which is not electrically connected to the ISO-NE Balancing Authority Area.

The overall New England and individual sub-area load forecasts used in the calculation of ICR, LSR and MCL for the 2017/18 CCP are documented within the *2013 Forecast Report of Capacity, Energy, Loads and Transmission (CELT Report)*.[27]

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 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 multipliers are allowed to vary by month.

The summer 2017 peak load forecast distribution is shown in Table 9. The values range from the 10th percentile, representing peak loads with a 90% chance of being exceeded, to the 95th 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 inputs to the GE MARS Model.

Table 9: Summer 2017 Peak Load Forecast Distribution (MW)

10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
28,325	28,590	28,940	29,340	29,790	30,265	30,750	31,445	32,210	32,900

Existing Capacity Resources

Market Rule 1, Section III.12.7.2 details what shall be modeled within the ICR, LSR and MCL 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

[27] Located on ISO-NE's website at: http://www.iso-ne.com/trans/celt/report/2013/index.html.

> 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 Load 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.[28] 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 2017/18 FCA ICR-Related Values calculations, there were a total of 35,443 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 Tables 10 – 15 of this report[29].

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. Existing Qualified Generating Capacity, by Load Zone, used within the ICR-Related Values calculations were based on Qualified Existing Generating Resources for the 2017/18 CCP at the time of the ICR calculation and is summarized in Table 10.

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

Load Zone	Summer
MAINE	2,883.184
NEW HAMPSHIRE	4,060.946
VERMONT	854.987
CONNECTICUT	8,595.280
RHODE ISLAND	1,865.977
SOUTH EAST MASSACHUSETTS	5,944.624
WEST CENTRAL MASSACHUSETTS	3,907.029
NORTH EAST MASSACHUSETTS & BOSTON	3,153.507
Total New England	**31,265.534**

[28] For detailed data on the Qualified Existing Resources that will be participating in the 8th FCA see: http://www.iso-ne.com/regulatory/ferc/filings/2013/nov/er14-329-000_11-5-13_fca8_info_filing_public.pdf.

[29] The Existing Qualified capacity resources shown in these tables excludes the August 2013 terminated capacity resources and resources removed after being determined to be "*Out of Market.*"

Intermittent Power Resources

Section III.13.1.2.2.2 of Market Rule 1 discusses the rating of resources considered as 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 2017/18 CCP and are shown in Table 11.

Table 11: Existing IPR by Load Zone (MW)

Load Zone	Summer	Winter
MAINE	202.897	275.189
NEW HAMPSHIRE	157.138	207.068
VERMONT	72.538	119.899
CONNECTICUT	188.984	203.672
RHODE ISLAND	5.867	7.280
SOUTH EAST MASSACHUSETTS	77.011	81.499
WEST CENTRAL MASSACHUSETTS	58.713	90.670
NORTH EAST MASSACHUSETTS & BOSTON	69.787	71.674
Total New England	**832.935**	**1,056.951**

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 as described above.

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 those that have Qualified as an Existing Demand Resource Capacity for the 2017/18 FCA, are shown in Table 12. These values are the Existing Qualified values which reflect the 8% Transmission and Distribution Gross-up as 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 Generators	Total
MAINE	165.955	0.000	313.079	27.344	506.378
NEW HAMPSHIRE	84.349	0.000	57.040	36.360	177.749
VERMONT	130.880	0.000	59.418	13.371	203.669
CONNECTICUT	90.548	333.838	329.028	230.542	983.956
RHODE ISLAND	148.529	0.000	73.588	59.975	282.092
SOUTH EAST MASSACHUSETTS	200.873	0.000	92.722	33.583	327.179
WEST CENTRAL MASSACHUSETTS	201.485	54.798	161.999	55.195	473.477
NORTH EAST MASSACHUSETTS & BOSTON	357.272	0.000	78.088	26.196	461.556
Total New England	1,379.890	388.636	1,164.962	482.567	3,416.055

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 limit. Table 13 shows the Existing Qualified Import Resources used within the ICR-Related Values calculations for the 2017/18 CCP and the corresponding external transmission interface supplying the capacity (MWs). There were no de-ratings for TTC for the Existing Qualified Import Capacity Resources for 2017/18. However; there was a 60 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
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
VJO - Highgate	6.000	Hydro-Quebec Highgate
Total MW	88.800	

Export Bids

An Export Bid is a 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 export of capacity was modeled within the ICR-Related Values calculation assumptions. This is the 100 MW sale 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.

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 to be modeled within the ICR calculations as all 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 and NEMA/Boston Load Zones, and the MCL for the export-constrained Maine Load Zone are calculated with resources located identified within the ISO-NE's Regional System Plan (RSP) sub-areas representing Connecticut, Boston and Maine respectively. These resources are used as proxies for resources located within those Load Zones. This is done because the TTC calculated for the interfaces studied in the locational requirements analyses are performed using the ISO-NE 13 zone RSP sub-areas and are thus calculated for the RSP zones. For the Demand Resources, the Existing Qualified Demand Resources for the Load Zone is used since the RSP values available would have to be estimated (particularly for the Passive Demand Resources) since actual locations for some of these resources is not available.

For the 2017/18 FCA ICR-Related Values, there are no differences between the resources located within the RSP zones versus the resources located within the Load Zones for Connecticut and NEMA/Boston and there is a difference of less than 0.5 MW for Maine. Table 15 shows the resources modeled in each of the Load Zones with a locational requirement along with the New England values.

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

Type of Resource	New England	Connecticut	NEMA/Boston	Maine
Generating Resources	31,105.534	8,595.280	3,153.507	2,883.184
Intermittent Power Resources	832.935	188.984	69.787	203.282
Passive Demand Resources	1,768.526	424.386	357.272	165.955
Active Demand Resources	1,647.529	559.570	104.284	340.423
Import Resources	88.800	-	-	-
Total MW Modeled in LRA and MCL	**35,443.324**	**9,768.220**	**3,684.850**	**3,592.844**

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 2017/18 CCP, if necessary. Although external transmission transfer capability is currently 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 the LSR and MCL.

External Transmission Transfer Capability

Table 16 shows the External TTC that were used within the tie benefits study.

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

External Interfaces: Canada and New York to New England	Summer Limit
Hydro-Quebec to New England (Phase II)	1,400
Hydro-Quebec to New England (Highgate)	200
New Brunswick to New England	700
New York to New England (New York AC Ties)	1,400
New York to New England (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 are associated with each transmission interface.

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

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

Internal Transmission Transfer Capability

For the 2017/18 FCA, ISO-NE evaluated three Load Zones relating to their LRA and MCL Requirements, using the Load Zone and *Rest of New England* methodology. The first is the Connecticut (CT) Load Zone, which is modeled as import-constrained into CT. The second is the NEMA/Boston Load Zone, which is modeled as import-constrained into NEMA/Boston. The third is the Maine (ME) Load Zone, which is modeled as export-constrained into the *Rest of New England*. In addition, the TSA analysis, which uses both the N-1 limit and the N-1-1 limit, was performed for the import-constrained Load Zones of CT and NEMA/Boston.

Table 18 shows the N-1 internal TTC for the Connecticut Import interface and the Boston Import interface used to calculate LRA requirements within the CT and NEMA/Boston Load Zones, respectively, and the Maine-New Hampshire Interface used in the calculation of MCL for the ME Load Zone. In addition, the N-1-1 Transfer Capability is also shown as an input into the TSA for CT and NEMA/Boston.

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

Interface	N-1 Limit	N-1-1 Limit
Connecticut Import	2,800	1,600
Boston Import	4,850	4,175
Maine-New Hampshire	1,900	-

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 for 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.

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

[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 does not include the New England East-West Solution (NEEWS) Interstate Reliability Program (IRP). This project is expected to be in-service by December 2015, however not all portions of the project have been certified to be operational by 2017/18. The TTC shown does include the impact of the Greater Springfield Reliability Program.

[32] The Maine-New Hampshire interface includes the Maine Power Reliability Program (MPRP) expected in-service by summer 2015.

[33] Action 6 and 8 of OP4.

[34] Action 2 of OP4.

[35] Action 6 of OP4.

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 and also for the individual interconnections between New England and these same Balancing Authority areas.

The tie benefits study for the 2017/18 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 7.

Figure 7: 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 needed 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 1,870 MW of tie benefits are assumed within the ICR calculations for the 2017/18 CCP.

[36] A presentation on the 2017/18 Tie Benefits Study was presented to the RC on September 18, 2013 which provides more details on the calculation process and study assumptions and is available here: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2013/sep182013/a5_fca8_hqicc_icr_values.zip.

Individual Balancing Authority Area Tie Benefits

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

For the 2017/18 CCP, the individual Balancing Authority area tie benefits were calculated as 1,151 MW for Québec, 492 MW for the Maritimes, and 227 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 to 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 to their relative Balancing Authority area's total tie benefits are different, then the tie benefits of each individual tie or group of ties are adjusted 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 2017/18 CCP, individual interconnection tie benefits were determined from Québec over the HQ Phase II facility of 1,068 MW, 83 MW from Québec over the Highgate facility, 227 MW of the New York tie benefits are delivered over the New York AC ties and 0 MW from the Cross-Sound Cable and 492 MW from the Maritimes over the New Brunswick interface.

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 entitlements (i.e. rights) over this transmission interconnection. These rights are monetized as credits in the form of reduced capacity requirements.

[37] The 2017/18 CCP HQICCs values were filed with the Commission in the 2017/18 ICR filing: http://www.iso-ne.com/regulatory/ferc/filings/2013/nov/er14-328-000_11-5-13__icr_2017-2018_.pdf.

The HQICC values are 1,068 MW as determined by the tie benefits from Québec over the Phase II facility, and are applicable for every month during the 2017/18 CCP.

Adjustments to Tie Benefits

Processes 5.0 of the 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 2017/18. 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 2017/18 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 2017/18 Tie Benefits Study, no adjustment to tie benefits to account for capacity imports was necessary.

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

Import	New Brunswick	Hydro-Québec Phase II	Highgate	New York AC Ties
NYPA - CMR				69
NYPA - VT				14
VJO - Highgate			6	
VJO - Phase I/II				
Total			6	81

The results of the Tie Benefits Study for the 2017/18 CCP are summarized in Table 20.

Table 20: 2017/18 Tie Benefits (MW)

Balancing Authority Area	Summer	Winter
Québec via Phase II	1,068	1,068
Québec via Highgate	83	83
Maritimes	492	492
New York	227	227
Total Tie Benefits	1,870	1,870

Comparison of the 2017/18 and 2016/17 CCP's Tie Benefits

Table 21 gives a comparison of the 2017/18 CCP tie benefits calculated for FCA8 and the 2016/17 CCP tie benefits calculated for FCA7.

Table 21: 2017/18 versus 2016/17 Tie Benefits (MW)

Balancing Authority Area	2017/18 FCA8	2016/17 FCA7
Québec via Phase II	1,068	1,055
Québec via Highgate	83	109
Maritimes	492	392
New York	227	314
Total Tie Benefits	1,870	1,870

As the results show, the total tie benefits for the New England Balancing Authority Area are the same both for the 2017/18 and the 2016/17 CCP. This is because the system conditions are similar for these two CCPs, specifically a similar amount of transmission import capability capacity imports (MWs) and OP-4 resources assumed. However, there is a change in the distribution of the tie benefits from the neighboring Balancing Authority Areas calculated for the 2017/18 versus 2016/17 CCP. These changes in the contribution from individual tie lines are mainly due to the West-East transmission interface constraint which was modeled for the first time within an ISO-NE tie benefits study. This interface shifted tie benefits from the western side to the eastern side of the West-East transmission interface, which results in an increase in the tie benefit contributions from the Maritimes and Québec, while decreasing the tie benefit contribution from New York.

5% Voltage Reduction

Under the FCM, 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. This benchmark reduction value is set based on the voltage reduction requirements of Operating Procedure No. 13, rather than at the self-reported values submitted by Market Participants with control over transmission/distribution facilities.

For the 2017/18 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 calculation. 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.

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), which is assumed to be already implemented and therefore not contributing to the 1.5% reduction in load. For the 2017/18 ICR calculation, the load relief obtainable from a 5% voltage reduction is calculated as:

Figure 8: Formula for Calculating 5% Voltage Reduction Assumption

$$[\mathit{90/10\ Peak\ Load\ MW} - \mathit{Demand\ Resource\ MW}] \times 1.5\%$$

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 2017/18 CCP within the ICR calculations.

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

	90/10 Peak Load	Passive Demand Resources	Real-Time Demand Resources	Real-Time Emergency Generation	Actions 6 & 8 5% Voltage Reduction
Jun 2017 - Sep 2017	32,210	1,769	1,165	483	432
Oct 2017 - May 2018	23,780	1,509	1,131	471	310

Operating Reserve

It is assumed that during peak load conditions, under extremely tight capacity situations, ISO-NE System Operations will hold a minimum 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 load.

Table 23 summarizes the capacity resource and OP-4 assumptions used for the calculation of the ICR-Related Values.

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

Type of Resource/OP-4	2017/18 FCA
Generating Resources	31,265.534
Intermittent Power Resources	832.935
Demand Resources	3,416.055
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(60.000)
OP 4 Voltage Reduction	432.000
Minimum Operating Reserve	(200.000)
Tie Benefits (Includes 1,068 MW of HQICCs)	1,870.000
Total MW Modeled in ICR	**37,545.324**

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 data available data of monthly Equivalent Forced Outage Rate - Demand (EFORd) values from NERC's Generating Availability Data System (GADS).[38] The NERC GADS data, submitted by regional generators to ISO-NE for the months of January 2008 through December 2013, was used to create an EFORd value for each 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 unit 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 unit-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 unit outages, scheduled more than 14 days in advance of their outage date. A single value is then calculated for each unit, 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 was used to calculate the average annual maintenance weeks for new capacity additions and immature units.

[38] The calculation methodology of EFORd can be found on the NERC website located at: http://www.nerc.com/files/Appendix_F_Performance_Indexes_and_Equations.pdf

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	12,160	3.9	6.2
Fossil	8,393	9.9	5.4
Nuclear	4,627	2.6	4.2
Hydro (Includes Pumped Storage)	2,892	5.1	6.5
Combustion Turbine	2,850	8.5	2.4
Diesel	227	7.8	0.9
Miscellaneous	116	15.8	1.1
Total System	31,266	5.9	5.3

Intermittent Power Resource Availability

The Qualified Capacity of an Intermittent Power Resource is the resource's median output during the "Reliability Hours," as averaged over a period of five years for the second FCA and subsequent auctions. 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	Availabilty (%)	Summer MW	Availabilty (%)
MAINE	165.955	100	-	-
NEW HAMPSHIRE	84.349	100	-	-
VERMONT	130.880	100	-	-
CONNECTICUT	90.548	100	333.838	100
RHODE ISLAND	148.529	100	-	-
SOUTH EAST MASSACHUSETTS	200.873	100	-	-
WEST CENTRAL MASSACHUSETTS	201.485	100	54.798	100
NORTH EAST MASSACHUSETTS & BOSTON	357.272	100	-	-
Total New England	1379.890	100	388.636	100

Active Demand Resources

The historical performance of Active Demand Resources (those in the Real-Time Demand Response and Real-Time Emergency Generators categories) are used to create an availability assumption for use within the ICR calculation.[39]

For the calculation of ICR for the 2017/18 CCP, there was available historical Demand Resource performance data for three years under FCM. This historical data consists of both OP-4 events and performance audits that occurred during the summer and winter of 2010 through 2012. At the June 3, 2013 PSPC meeting, ISO-NE proposed using an availability assumption for Active Demand Resources based on the summer 2010 through 2012 Active Demand performance data, 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 additional 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 within the 2017/18 FCA. This gives an average Active Demand Resource availability assumption of 88% for both Real-Time Demand Response and Real-Time Emergency Generators combined. The total average Demand Resource availability assumption for all Demand Resources, both Active and Passive, is 94%. This is an increase in performance of approximately 2% over prior values assumed for the 2016/17 ICR-Related Values calculation, which used historical data from summer 2010 and 2011. In the ICR model, DR is modeled in blocks consisting of the type of DR by Load Zone. The overall availability is shown for informational purposes only.

[39] A detailed discussion of the Demand Resource availability assumption is available here: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2013/jun32013/2013_dr_availability_icr_revised_082013.pdf.

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

Load Zone	RT Demand Response		RT Emergency Gen	
	Summer MW	Availabilty (%)	Summer MW	Availabilty (%)
MAINE	313.079	100	27.344	93
NEW HAMPSHIRE	57.040	95	36.360	100
VERMONT	59.418	100	13.371	77
CONNECTICUT	329.028	81	230.542	86
RHODE ISLAND	73.588	86	59.975	84
SOUTH EAST MASSACHUSETTS	92.722	75	33.583	78
WEST CENTRAL MASSACHUSETTS	161.999	91	55.195	86
NORTH EAST MASSACHUSETTS & BOSTON	78.088	79	26.196	82
Total New England	1164.962	89	482.567	86

Difference from 2016/17 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 2016/17 CCP and substituted each assumption individually with the corresponding 2017/18 CCP assumption. The net of these changes within the ICR value, as a result from each individual input assumption change, was then considered as the overall effect of the changed assumption set. Table 27 lists the assumptions for each study year 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 2017/18 vs. 2016/17

Assumption	2017/2018 FCA		2016/2017 FCA		Effect on ICR (MW)
Tie Benefits & Updated External Interface Outage Assumptions	227 MW New York		314 MW New York		19
	492 MW Maritimes		392 MW Maritimes		
	1068 MW Quebec (HQICCs)		1055 MW Quebec (HQICCs)		
	83 MW Quebec via Highgate		109 MW Quebec via Highgate		
Total	1,870 MW		1,870 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	32,098	5.8%	31,591	4.6%	410
Demand Resources	3,416	5.8%	3,545	8.3%	-89
Imports & Sales	-11	0.0%	12	0.0%	5
	MW		MW		
Load Forecast	29,790		29,400		581
	MW	%	MW	%	
OP 4 5% VR	432	1.50%	422	1.50%	-10
	MW		MW		
ICR	34,923		34,023		900

As shown in Table 27, there are two assumptions which have the greatest effect on the ICR. The first is the increase in generating resource EFORd calculated for the 2017/18 ICR-Related Values from those calculated for the 2016/17 ICR-Related Values. This increase in generating resource unavailability caused the ICR to increase by approximately 400 MW.

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 average EFORd calculated for the 2017/18 ICR calculation is approximately 20% higher than the EFORd values calculated for the 2016/17 ICR calculation. Table 28 shows a comparison in the 2017/18 versus the 2016/17 FCA ICR calculation average EFORd by generator type.

Table 28: Assumed 5-Year Average % EFORd Weighted by Summer Ratings for 2017/18 versus 2016/17 ICR Calculations

Resource Category	2017/18 FCA8 5-Year Average EFORd	2016/17 FCA7 5-Year Average EFORd
Combined Cycle	3.9	3.6
Fossil	9.9	7.2
Nuclear	2.6	2.4
Hydro (Includes Pumped Storage)	5.1	3.3
Combustion Turbine	8.5	7.5
Diesel	7.8	6.5
Miscellaneous	15.8	10.3
Total System	5.9	4.8

In order to look at the increase in EFORd in more detail, an analysis was performed that examined a common set of generating resources for the two ICR calculations to gauge if specific resources types were causing the increase in generator unavailability. The EFORd calculated for the 2017/18 ICR calculation consisted of outages reported to GADS for the five year period of January 2008 through December 2012. The 5-year average EFORd for the 2016/17 ICR calculation consisted of outages from February 2007 through January 2012. The change in time period between the ICR calculations saw an increase in EFORd of approximately 21% for the common set of generating resources.

Table 29 shows the generator type and primary fuel with the associated weighted average EFORd for each category. This table shows that the largest increase in EFORd is from natural gas combined cycle generators (36%), followed by residual fuel oil (RFO) steam turbines (17%) and nuclear generators (16%). When looking at the capacity (MWs) of the generating resources in order to weight the EFORd contribution to the total system EFORd, the largest contributor to the 21% increase in EFORd is the RFO generators which accounted for 8% of the overall 21% increase. Coal and natural gas steam turbines each contributed 3% to the increase. Other fuel types make up the rest of the increase. It should be noted that while fossil generators have been showing the highest trend of increasingly degraded performance, generating unit unavailability has been increasing across many different generation technologies and fuel types.

Table 29: Increase in 5-year Average EFORd for FCA8 Vs. FCA7 (%)

Generator Type	Primary Fuel Type	Percent Change FCA8 Vs. FCA7 ICR Calculation	Contribution to the 21.3% Increase
Combined Cycle	Natural Gas	36%	2%
Gas Turbine	Diesel	2%	0%
	Jet	1%	0%
	Kerosene	2%	2%
	Landfill Gas	0%	0%
	Natural Gas	3%	0%
Hydro - Pondage	Water	1%	1%
Hydro - Run of River	Water	1%	1%
Hydro - Weekly Cycle	Water	2%	1%
Internal Combustion	Diesel	1%	0%
	Landfill Gas	0%	0%
	Municipal Solid Waste	0%	0%
	Natural Gas	0%	0%
	Other Biomass Liq	0%	0%
Pumped Storage	Water	6%	2%
Photo Voltaic	Sun	0%	0%
Steam Turbine	Coal	6%	3%
	Municipal Solid Waste	1%	0%
	Natural Gas	2%	3%
	Nuclear	15%	1%
	Residual Fuel Oil	17%	8%
	Sub-Bituminous Coal	1%	0%
	Tire Derived	0%	0%
	Woods/Wood Solids	1%	0%
Wind Turbine	Wind	0%	0%
		100%	21.3%

Another assumption change that requires discussion is the change in the load forecast. The 50/50 peak load forecast increased by 390 MW for the 2017/18 ICR calculation over the value forecasted for the 2016/17 ICR calculation, while the corresponding ICR increased by 581 MW. This is due to the fact that the ICR model sees an entire distribution of possible load forecast values and the distribution for the 2013 CELT Load Forecast (used to calculate the ICR for the 2017/18 CCP) has more uncertainty than that of the 2012 CELT Load Forecast (used to calculate ICR for the 2016/17 CCP), particularly when related to skewness of the weekly distributions, which is a measure of the asymmetry of the distribution. Skewness in the model is represented by the Third Cumulant (skewness cubed), which is one of the moments of the distribution and describes the values at the tail ends of the distributions. The change in load forecast uncertainty contributed approximately 130 MW to the overall increase in ICR.

The next three tables document this change in load forecast uncertainty. Table 30 shows the two load forecast's weekly means, Table 31 shows the standard deviations of the two load forecasts and Table 32 shows the Third Cumulant of the two load forecasts.

Table 30: 2013 CELT vs. 2012 CELT 2017/18 CCP Weekly Load Forecast Mean (MW)

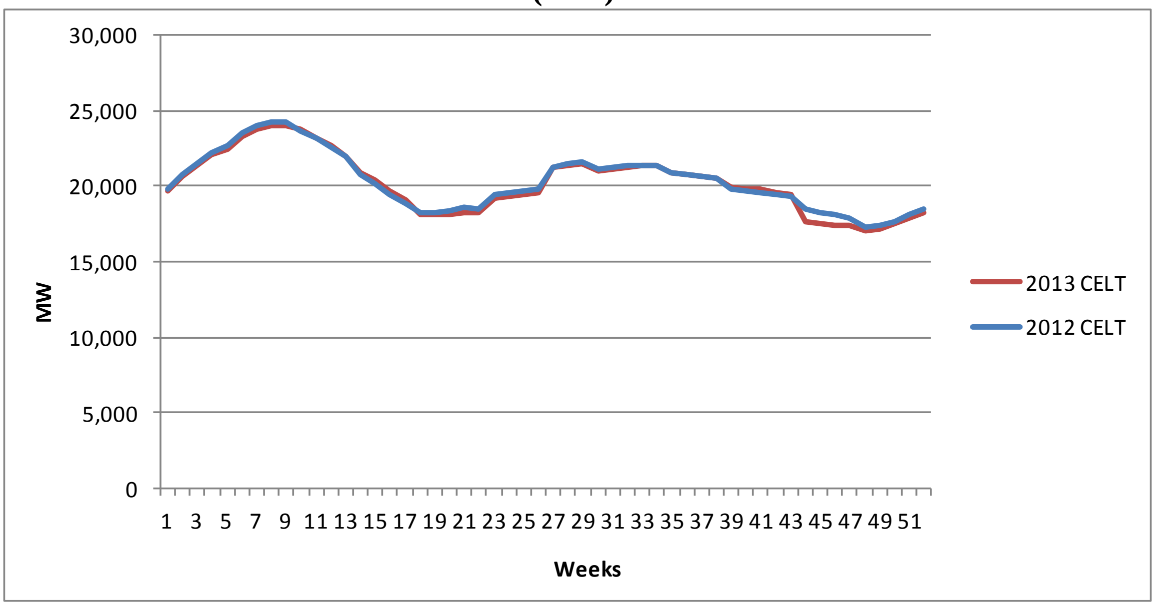


Table 31: 2013 CELT vs. 2012 CELT 2017/18 CCP Weekly Load Forecast Standard Deviation

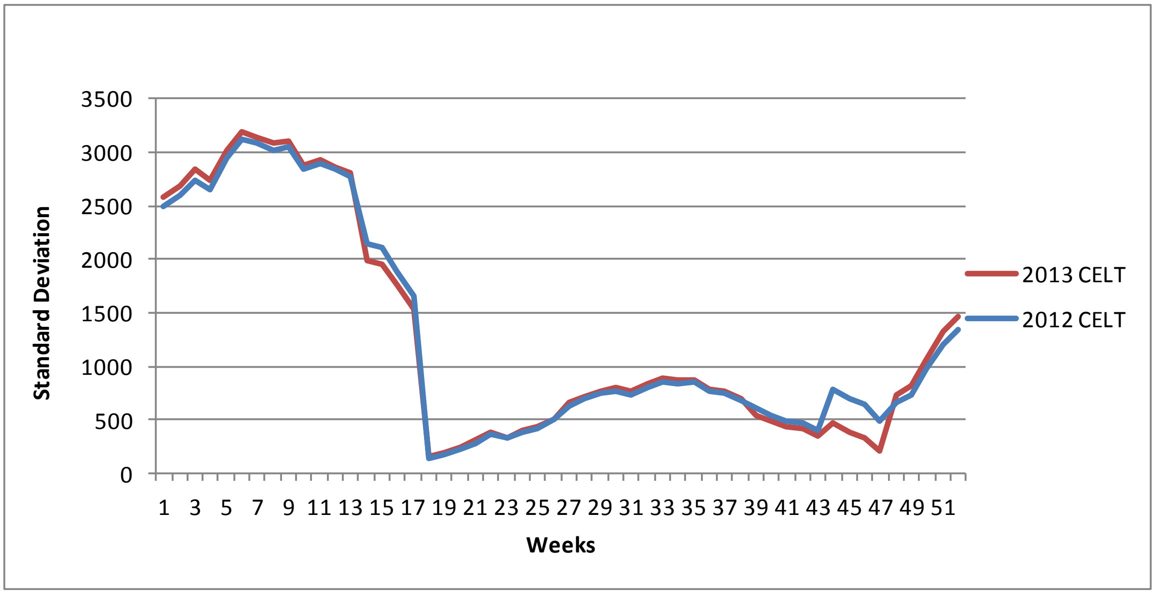
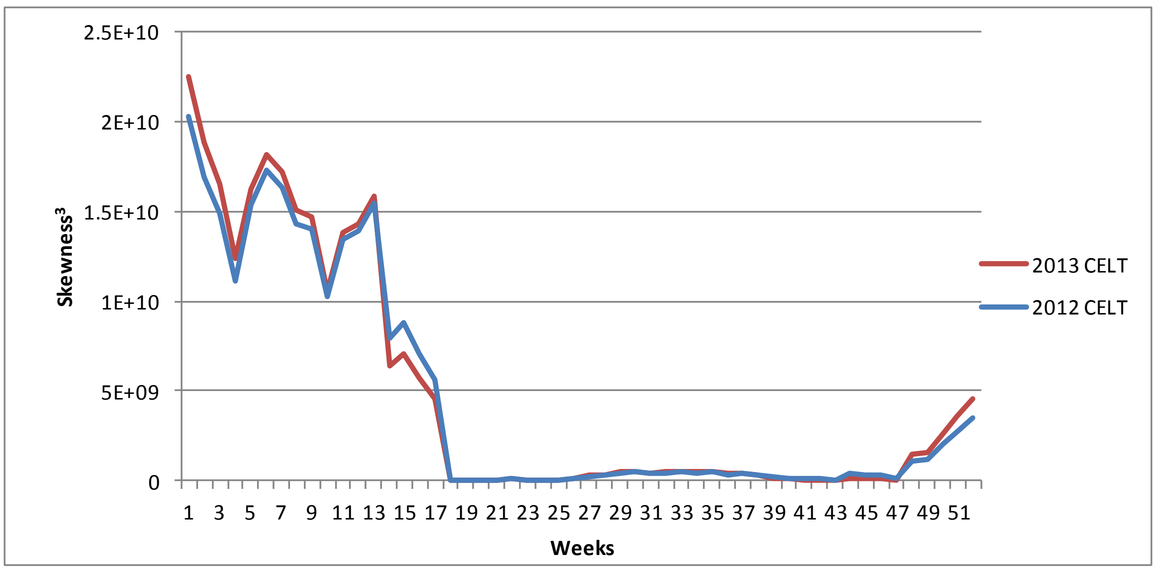


Table 32: 2013 CELT vs. 2012 CELT 2017/18 CCP Weekly Load Forecast Third Cumulant



Change in LRA Requirement

Table 33 shows the difference in the assumptions and results of the 2017/18 LRA Requirement calculation, as compared to the 2016/17 LRA Requirement calculation for the import-constrained Connecticut and NEMA/Boston Load Zones and the Rest of New England area, which is used in the calculation of the Maine MCL.

Table 33: Summary of Changes in LRA Requirement for 2017/18 vs. 2016/17

		Connecticut		NEMA/Boston		Rest of New England	
		2017/18 FCA	2016/17 FCA	2017/18 FCA	2016/17 FCA	2017/18 FCA	2016/17 FCA
$Resource_z$	[1]	9,768	9,004	3,685	3,228	31,850	31,416
Proxy $Units_z$	[2]	0	0	0	0	0	0
Proxy Units $Adjustment_z$	[3]	0	0	0	0	1,570	2,170
Firm Load $Adjustment_z$	[4]	2,282	1,298	685	717	268	-125
FOR_z	[5]	0.0682	0.0732	0.0442	0.0396	0.0605	0.0520
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**7,319**	**7,603**	**2,968**	**2,481**	**29,894**	**29,259**

Change in TSA Requirement

Table 34 shows the difference in the assumptions and results of the 2017/18 TSA Requirement calculation, as compared to the 2016/17 TSA Requirement calculations for the import-constrained Connecticut and NEMA/Boston Load Zones.

Table 34: Comparison of the TSA Requirement Calculation for 2017/18 vs. 2016/17 (MW)[40]

	Connecticut		NEMA/Boston	
	2017/18 FCA	2016/17 FCA	2017/18 FCA	2016/17 FCA
Sub-area 90/10 Load	8,330	8,201	6,745	6,520
Reserves (Largest unit or loss of import capability)	1,200	1,225	1,395	1,393
Sub-area Transmission Security Need	**9,530**	**9,426**	**8,140**	**7,913**
Existing Resources	9,768	9,004	3,685	3,228
Assumed Unavailable Capacity	-729	-797	-149	-147
Sub-area N-1 Import Limit	2,800	2,600	4,850	4,850
Sub-area Available Resources	**11,839**	**10,807**	**8,386**	**7,931**
TSA Requirement	**7,273**	**7,489**	**3,428**	**3,209**

Connecticut

The primary reason for the decrease in the Connecticut LRA and TSA Requirements for the 2017/18 CCP versus the 2017/17 CCP is the increase in the N-1 TTC for the Connecticut Import interface used to calculate the Connecticut LRA Requirement and the N-1 and N-1-1 TTC used to calculate the TSA Requirement. The N-1 TTC increased from 2,600 MW to 2,800 MW. The N-1-1 TTC increased from 1,400 MW to 1,600 MW. This increase in the Connecticut Import TTC is due to transmission upgrades associated with the New England East-West Solution (NEEWS) Great Springfield Reliability Program project, which was placed in service during 2013. The increase in TTC means that an import-constrained Load Zone needs less resources installed within the Load Zone in order to meets the LRA and TSA Requirements.

[40] 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.

NEMA/Boston
The increase in the NEMA/BOSTON LRA and TSA Requirements for the 2017/18 CCP is primarily due to an increase in the load forecast for the NEMA/Boston sub-area. The forecasted load for the Boston sub-area increased by approximately 120 MW due to changes in the local distribution companies reported distribution of load to the load buses used in the Transmission Planning Network Model. The Boston sub-area load forecast is used as a proxy for the NEMA/Boston Load Zone load forecast, since the transmission transfer capability limit is calculated using the ISO-NE RSP 13 sub-area system model. This 120 MW increase in load forecast means that more resources must be located within the NEMA/BOSTON Load Zone in order to satisfy both the LRA and the TSA Requirements.

In order to forecast the sub-areas loads, the load forecast is produced using econometric models of state level data. Then the share of the state load forecast is distributed to the operating companies based on historical percentages. The next step is to distribute the share of the operating companies to ISO-NE's RSP sub-areas. This is done based on bus level data provided by Transmission Operators to the Transmission Network Model[41]. Table 35 shows the distribution of the state load forecast to the operating companies and then to the ISO-NE RSP sub-areas.

Table 35: Distribution of the 2013 CELT Load Forecast to the RSP Sub-areas[42]

		RSP Sub-area												
% of State Peak	Operating Company	BHE	ME	SME	NH	VT	BOSTON	CMA/ NEMA	WMA	SEMA	RI	CT	SWCT	NOR
4.71	CMEEC											73.34	22.47	4.19
76.26	CLP								1.80			58.19	21.46	18.56
19.02	UI											4.08	82.14	13.78
14.59	BHE	100.00												
85.41	CMP	0.56	52.39	43.19	3.85									
11.63	COMEL						29.24			70.76				
28.31	BECO						92.02			4.80	3.18			
39.33	MA-NGRID						26.31	26.97	14.88	20.98	10.88			
1.86	MUNI:SEMA-NGRID									100.00				
2.20	MUNI:WMA-NU								100.00					
1.01	MUNI:WMA-NGRID								100.00					
2.10	MUNI:CNEMA-NGRID							100.00						
0.88	MUNI:RI-NGRID										100.00			
6.34	WMECO								100.00					
1.21	MUNI:BOST-NSTAR						100.00							
3.40	MUNI:BOST-NGRID						100.00							
1.74	MUNI:SEMA-NSTAR									100.00				
78.73	PSNH				85.91	11.58		2.51						
12.13	UNITIL				100.00	0.00								
9.14	GSE				8.39	45.41	36.13	10.07						
100.00	RI-NGRID									8.86	91.14			
100.00	VELCO				6.99	86.53			6.48					

As described above, the Boston sub-area load forecast increased by approximately 120 MW in the 2013 CELT versus the CELT 2012 load forecast due to the changes in the operating company distribution of the load to the load buses used in the Transmission Planning Network Model. Table 36 shows the movement in the load for Massachusetts

[41] For more information, see the Load Forecast Details website: http://www.iso-ne.com/trans/celt/fsct_detail/index.html.
[42] For more information on the RSP sub-areas, see: http://www.iso-ne.com/trans/rsp/index.html.

operating companies (2013 CELT minus 2012 CELT distribution) by portions of operating company coincident peak in each sub-area. Approximately 3% of Massachusetts load moved into the Boston RSP sub-area from the SEMA sub-area and 1% moved from the RI sub-area. These changes account for the overall 120 MW increase in the Boston load used in the NEMA/Boston LRA and TSA Requirements calculation.

Table 36: Changes to the Boston Sub-area Load – 2013 CELT Vs. 2012 CELT (%)

		RSP Sub-area				
% of State	Operating Company	BOSTON	CMA/NEMA	SEMA	RI	WMA
11.63	COMEL	**2.94**		**-2.94**		
28.31	BECO	**0.19**		**-0.18**	**-0.01**	
39.33	MA-NGRID	**1.00**	**0.11**	**0.20**	**-1.29**	**0.00**
1.86	MUNI:SEMA-NGRID			**0.00**		
2.20	MUNI:WMA-NU					**0.00**
1.01	MUNI:WMA-NGRID					**0.00**
2.10	MUNI:CNEMA-NGRID		**0.00**			
0.88	MUNI:RI-NGRID				**0.00**	
6.34	WMECO					**0.00**
1.21	MUNI:BOST-NSTAR	**0.00**				
3.40	MUNI:BOST-NGRID	**0.00**				
1.74	MUNI:SEMA-NSTAR			**0.00**		

Change in MCL

Table 37 shows the difference in the assumptions and results of the 2017/18 MCL calculation, as compared to the 2016/17 MCL calculation for the Maine Load Zone.

Table 37: Comparison of MCL Calculation for 2017/18 vs. 2016/17 for Maine (MW)

		2017/18 FCA	2016/17 FCA
ICR for New England	[1]	33,855	32,968
$LRA_{RestofNewEngland}$	[2]	29,894	29,259
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,960**	**3,709**

The increase in Maine MCL in the 2017/18 CCP versus the 2016/17 CCP can be attributed to an increase in the TTC limit of the export interface used in calculating the Maine MCL from 1,600 MW to 1,900 MW. The increase in the TTC is due to transmission upgrades from the Maine Power Reliability Program (MPRP) expected to be in service in the 2015/16 CCP. The effects of the MPRP transmission upgrades were under study and the impacts were unknown when the Maine MCL for the 2016/17 CCP were calculated last year.

Table 38 shows the summary comparison between the all the ICR-Related Values and their inputs calculated for the 2017/18 FCA versus the 2016/17 FCA.

Table 38: Comparison of all ICR-Related Values (MW)[43]

	New England		Connecticut		NEMA/Boston		Maine	
	2017/18 FCA	2016/17 FCA	2017/18 FCA	2016/17 FCA	2017/18 FCA	2016/17 FCA	2017/18 FCA	2016/17 FCA
Peak Load (50/50)	29,790	29,400	7,650	7,555	6,260	6,047	2,115	2,108
Total Resources	35,443	35,178	9,768	9,004	3,685	3,228	3,593	3,762
Installed Capacity Requirement	34,923	34,023						
NET ICR (ICR Minus HQICCs)	33,855	32,968						
Local Resource Adequacy Requirement			7,319	7,603	2,968	2,481		
Transmission Security Requirement			7,273	7,489	3,428	3,209		
Local Sourcing Requirement			7,319	7,603	3,428	3,209		
Maximum Capacity Limit							3,960	3,709

[43] Total Resources value for New England excludes HQICCs.

{ End of Report }