ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2014/15 Capability Year

ISO New England Inc.
April 2011

ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2014/15 Capability Year

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 2014/15 Capability Year. The auction, which will be conducted on June 6, 2011, is intended to result in capacity commitments of sufficient quantities (megawatts) to meet the Installed Capacity Requirement (ICR) for the Capability Commitment Period (CCP) 2014/15. The 2014/15 CCP is the fifth Capability Year of the FCM and it begins on June 1, 2014 and ends on May 31, 2015.

In this report, ISO-NE is documenting the assumptions and results of the 2014/15 Capability Year ICR, Local Sourcing Requirements (LSR) and Maximum Capacity Limit (MCL) – (collectively the "*ICR-Related Values*") all of which are key inputs in the FCA – and Hydro-Québec Interconnection Capability Credits (HQICCs), which are a key input into the calculation of the ICR.

The ICR is a measure of the installed resources that are projected to be necessary to meet both ISO-NE and the Northeast Power Coordination Council's (NPCC) reliability standards, with respect to satisfying the peak demand forecast for the New England Balancing Authority area while maintaining sufficient reserve capacity. More specifically, the ICR is the amount of resources 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).

In general, the methodology used for calculating the ICR-Related Values for the 2014/15 FCA is consistent with the methodology used in prior years. However, for the first time, ISO-NE is utilizing the General Electric Multi-Area Reliability Simulation Model (GE MARS) to calculate the ICR in place of the Westinghouse Capacity Model Program (Capacity Model) which has been used in all previous ICR calculations. [1] In addition to this change, ISO-NE has also changed the methodology for calculating tie benefits, another input assumption impacting the ICR-Related Values, using the new Market Rule 1 Revisions to Tie Benefits Calculation Methodology as filed with the Federal Energy Regulatory Commission ("Commission") by ISO-NE on December 30, 2010 and accepted by the Commission in their February 28, 2011 Order. [2,3]

[1] Developed by the Westinghouse Electric Corporation/ABB

[2] ISO-NE Docket Number ER11-2580-000 dated December 30, 2010 which is located at: http://www.iso-ne.com/regulatory/ferc/filings/ /dec/er11-2580-000_12-30-10_tie_benefits.pdf

[3] Order Accepting ISO New England's Proposed Revisions to the Tie Benefits Calculation Methodology, Subject to Condition, and Directing Compliance Filing at: http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2580-000_2-28-11_order_tie_benefits.pdf

The ICR for the 2014/15 Capability Year was established through a stakeholder process in accordance with the calculation methodology prescribed in Section III.12 of Market Rule 1.[4] The stakeholder process consisted of review and comment from the NEPOOL Power Supply Planning Committee (PSPC) and NEPOOL Reliability Committee (RC) on ISO-NE's development of load and resource assumptions and ISO-NE's subsequent calculation of the ICR-Related Values for the 2014/15 Capability Year's FCA. [5]

After the PSPC's review and comment, ISO-NE developed a recommendation regarding both the ICR-Related Values and HQICCs for the 2014/15 Capability Year. ISO-NE presented this recommendation, along with the associated load and resource assumptions, to the RC for their review, comment and action. At the January 20, 2011 RC meeting, a motion to recommend that the NEPOOL Participant's Committee (PC) support ISO-NE's proposed ICR-Related Values and HQICCs passed with a show of hands vote.

ISO-NE then presented the ICR-Related Values, HQICCs, and results of the RC action to the NEPOOL PC for its review and action. At the February 4, 2011 PC meeting, the ICR-Related Values were placed on the Consent Agenda and subsequently passed with a show of hands, with only five oppositions and three abstentions. The New England States Committee on Electricity (NESCOE) also reviewed and commented on the ICR-Related Values as part of their participation on several NEPOOL Committees. After taking the comments received from the PC and NESCOE into consideration, ISO-NE filed with the FERC, the ICR-Related Values and HQICCs for the 2014/15 Forward Capacity Auction.[6]

[4] Market Rule1: http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1_12.pdf
[5] Includes both qualified supply and demand-side resources, as well as qualified imports
[6] The ISO-NE filing is located at: http://www.iso-ne.com/regulatory/ferc/filings/2011/mar/er11-___-000_03-08-11_icr_2014-2015.pdf.

ISO-NE has determined the ICR-Related Values for the 2014/15 Capability Year to be those shown in Table 1. The monthly values for the HQICCs are provided in Table 2.

Table 1: Summary of 2014/15 ICR-Related Values (MW)[7,8]

	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	29,025	7,585	5,805	2,185
Total Resources	36,838	9,505	3,943	3,712
Installed Capacity Requirement	34,154			
NET ICR (ICR Minus 954 MW of HQICCs)	33,200			
Local Sourcing Requirement		7,478	3,046	
Maximum Capacity Limit				3,702

Table 2: Monthly HQICCs

Month	MW
June 2014	954
July 2014	954
August 2014	954
September 2014	954
October 2014	954
November 2014	954
December 2014	954
January 2015	954
February 2015	954
March 2015	954
April 2015	954
May 2015	954

[7] The net amount of capacity to be purchased in the Forward Capacity Auction to meet the ICR, after reflecting a reduction in capacity requirements relating to the 954 MW of HQICCs that are allocated to the Interconnection Rights Holders (IHR), is the Net ICR value of 33,200 MW.
[8] 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 6
Introduction 7
Summary of ICR-Related Values and Components for 2014/15 8
Stakeholder Process 9
Methodology 10
    Reliability Planning Model for ICR-Related Values 10
    Installed Capacity Requirement (ICR) Calculation 11
    Local Sourcing Requirements (LSR) Calculation 12
Local Resource Adequacy (LRA) Requirement 12
    Transmission Security Analysis (TSA) Calculation 15
    Methodology for Calculating the TSA 15
    Local Sourcing Requirement (LSR) 16
    Maximum Capacity Limit (MCL) Calculation 16
Assumptions 19
Load Forecast 19
    Load Forecast Uncertainty 19
Existing Capacity Resources 20
    Generating Resources 21
    Intermittent Power Resources 21
    Demand Resources 22
    Import Resources 23
Export Bids 24
New Capacity Resources 24
Transmission Transfer Capability 24
    External Transmission Transfer Capability 24
    Internal Transmission Transfer Capability 25
OP 4 Load Relief 25
    Tie Benefits 25
    5% Voltage Reduction 28
Operating Reserve 29
Availability 29
    Generating Resource Forced Outages 29
    Generating Resource Scheduled Outages 30
    Intermittent Power Resource Availability 30
    Demand Resources Availability 31
Difference from 2013/14 FCA ICR-Related Values 33

List of Tables

Table 1: Summary of 2014/15 ICR-Related Values (MW) 3
Table 2: Monthly HQICCs.. 3
Table 3: ICR-Related Values and Components for 2014/15 (MW) 8
Table 4: Variables Used to Calculate ICR (MW).. 12
Table 5: LRA Requirement Calculation Details (MW).. 14
Table 6: LSR for the 2014/2015 Capability Year (MW).. 16
Table 7: MCL Calculation Details (MW)... 18
Table 8: Summer 2014 Peak Demand Forecast Distribution (MW)................................ 20
Table 9: Existing Qualified Generating Capacity by Load Zone (MW) 21
Table 10: Existing IPR by Load Zone (MW) 22
Table 11: Existing Demand Resources by Load Zone (MW).. 23
Table 12: Existing Import Resources (MW).. 23
Table 13: External Transmission Transfer Capability (MW) 24
Table 14: Transmission Transfer Capability (MW)... 25
Table 15: OP 4 Action 6 & 8 Modeled (MW) 29
Table 16: Summary of Resource and OP 4 Assumptions (MW).................................... 29
Table 17: Generating Resource EFORd (%) and Maintenance Weeks by Resource Category.. 30
Table 18: Passive Demand Resources – Summer (MW) and Performance (%)............... 31
Table 20: Summary of ICR Input Assumptions for 2013/14 vs. 2014/15........................ 33
Table 21: Summary of Changes in LRA for 2013/14 vs. 2014/15.................................. 34
Table 22: Summary of Differences in MCL for 2013/14 vs. 2014/15 for ME (MW)...... 34
Table 23: Summary of Changes to ICR-Related Values (MW) 35

List of Figures

Figure 1: Formula for Annual Resulting Reserves (%) 8
Figure 2: Formula for ICR Calculation.. 11
Figure 3: Formula for LRA Calculation 14
Figure 4: Surplus Capacity Adjustment in Rest of New England 14
Figure 5: Formula for TSA Calculation... 15
Figure 6: Formula for MCL Calculation.. 17

Introduction

The Installed Capacity Requirement (ICR) is an ISO-projected measure of the capacity that is necessary to satisfy the resource adequacy requirements of ISO New England's (ISO-NE) Balancing Authority area's forecasted electrical peak load requirements, which also includes sufficient reserve capacity to meet regional reliability standards. More specifically, ICR is the amount of capacity needed to meet the requirements defined for the New England Balancing Authority area such that the probability of disconnecting non-interruptible customers (a loss of load expectation or "LOLE"), on average, is no more than once in every ten years (an LOLE of 0.1 days/year). This criterion takes into account: the possible levels of peak electric loads due to weather variations, the impacts of assumed generating unit 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).[9]

This report discusses the derivation of the ICR, Local Sourcing Requirements (LSR) and Maximum Capacity Limits (MCL), (collectively, the "ICR-Related Values") and the Hydro-Québec Interconnection Capability Credits ("HQICCs") for the 2014/15 Capability Year's Forward Capacity Auction (FCA) to be conducted on June 6, 2011. The 2014/15 Capability Year starts on June 1, 2014 and ends on May 31, 2015.

This report also addresses the general process and methodology 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 is 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.

[9] ISO-NE OP4 is located at: http://www.iso-ne.com/rules_proceds/operating/isone/op4/index.html

Summary of ICR-Related Values and Components for 2014/15

Table 3 documents the ICR and components relating to the calculation of ICR and the related values.

Table 3: ICR-Related Values and Components for 2014/15 (MW)[10]

2014/2015 FCA	New England	Connecticut	NEMA/ Boston	Maine
Peak Load (50/50)	29,025	7,585	5,805	2,185
Total Resources	36,838	9,505	3,943	3,712
Installed Capacity Requirement	34,154			
HQICCs	954			
NET ICR (ICR Minus 954 MW of HQICCs)	33,200			
Local Resource Adequacy Requirement		7,434	2,549	
Transmission Security Analysis Requirement		7,478	3,046	
Local Sourcing Requirement		7,478	3,046	
Maximum Capacity Limit				3,702

The 34,154 MW Installed Capacity Requirement value does not reflect a reduction in capacity requirements relating to HQICCs that are allocated to the Interconnection Rights Holders in accordance with Section III.12.9.2 of Market Rule 1. After deducting the HQICC value of 954 MW per month, the net Installed Capacity Requirement for use in the 2014/2015 FCA is 33,200 MW, which is described as the *Net ICR.*

The 34,154 MW of ICR results in an annual resulting reserves value of 14.4 % when excluding HQICCs. The annual resulting reserves 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 Reserves (%)

Annual Resulting Reserves (%) =

- - - - x 100

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

Stakeholder Process

The ICR for the 2014/15 Capability Year was established through a stakeholder process and in accordance with the calculation methodology prescribed in Section III.12 of Market Rule 1. The stakeholder process consisted of NEPOOL Power Supply Planning Committee (PSPC) review and comment, NEPOOL Reliability Committee (RC) review and vote and NEPOOL Participant Committee (PC) vote on ISO-NE's development of load and resource assumptions and ISO-NE's calculation of the ICR-Related Values for the 2014/15 Capability Year's Forward Capacity Auction.

The PSPC is a non-voting technical subcommittee under the RC, chaired by ISO-NE. Most PSPC members are representatives of the NEPOOL Participants. The PSPC assists ISO-NE with the development of resource adequacy based requirements such as the ICR, LSR and MCL, including appropriate load and resource assumptions for modeling expected system conditions. Representatives of the six New England States' public utility regulatory commissions and the New England States Committee on Energy (NESCOE) also participate in these NEPOOL Committee discussions. Members of these regulatory agencies were present for the PSPC meetings at which the resource adequacy based requirements and HQICCs for the 2014/15 FCA were discussed and considered.

After the PSPC's review and comment, ISO-NE developed a recommendation regarding the ICR-Related Values and HQICCs for the 2014/15 Capability Year. ISO-NE then presented this recommendation, along with the associated load and resource assumptions, to the RC for their review, comment and action. At their January 20, 2011 meeting, the RC voted to recommend both the ICR-Related Values and HQICCs with a vote taken by show of hands.[11] ISO-NE then presented the RC approved ICR-Related Values and HQICCs to the PC for their review and action. At their February 4, 2011 meeting, the PC approved the Consent Agenda, of which the ICR-Related Values and HQICCs were a part of, with a show of hands vote with only five oppositions and three abstentions. ISO-NE subsequently filed the ICR-Related Values and HQICCs with the FERC for the 2014/15 Forward Capacity Auction on March 8, 2011.[12]

[11] RC vote for the HQICCs included two opposed (2 Supplier Sector) and six abstentions (3 Transmission Sector, 2 Generation Sector, 1 Supplier Sector) and for the ICR-Related Values included four opposed (1 Transmission Sector, 2 Supplier Sector, 1 End User Sector) and seven abstentions (3 Transmission Sector, 1 Supplier Sector, 3 End User Sector).

[12] A copy of the filing is available at: http://www.iso-ne.com/regulatory/ferc/filings/2011/mar/er11-3048-000_03-08-11_icr_2014-2015.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,[13] *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 noninterruptible 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 noninterruptible 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 2014/15 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 compute the resource adequacy of a 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, the GE MARS Monte Carlo process repeatedly simulates the year (multiple replications) and evaluates the impacts of a wide-range of possible random combinations of generator outages. Chronological system histories are

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

developed by combining randomly generated operating histories of the generating units 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

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

Where:	APk	= Annual Peak Load Forecast for summer
	Capacity	= Total Capacity (Sum of all supply and demand resources)
	Tie Benefits	= Tie Reliability Benefits
	OP4 Load Relief	= Load Relief from 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 in the amount of capacity needed or additional load required to attain the resource adequacy criterion is also identified. If the system is more reliable than the resource-adequacy criterion (i.e., the system LOLE is less than or equal to 0.1 days per year), additional resources are not required, and the Installed Capacity Requirement is determined by increasing loads (A*dditional Load Carrying Capability* or ALCC) so that New England's LOLE is exactly at 0.1 days per year. For the 2014/15 Capability Year, the New England system, as simulated, 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. [14] In the ICR calculation, the HQICCs are treated differently than other

[14] 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.

resources; they are not adjusted by the ALCC amount. Table 4 shows the details of the variables used to calculate the ICR for the Capability Year 2014/15.

Table 4: Variables Used to Calculate ICR (MW)

Total Capacity Breakdown	2014/15
Generation and Intermittant Resources	32,922
Tie Benefits	1,689
Imports/Sales	173
Demand Resources	3,603
OP 4 Action 6 & 8 - Min Res	216
Expansion Unit Capacity	-
Capacity	38,603

Installed Capacity Requirement Calculation Details	2014/15
Annual Peak	29,025
Capacity	38,603
Tie Benefits	1,689
HQICCs	954
OP4 - Action 6 & 8	416
Minimum Reserve Requirement	(200)
ALCC	3,058
Installed Capacity Requirement	**34,154**
Net ICR	**33,200**

Local Sourcing Requirements (LSR) Calculation

The methodology for calculating LSR for import-constrained Load Zones involves calculating both the a local resource adequacy criteria called the Local Resource Adequacy (LRA) Requirement and a transmission security criteria called the Transmission Security Analysis (TSA) Requirement that ISO-NE uses to maintain system operational reliability when reviewing de-list bids of resources within the auctions of the FCM. [15] The system must meet both resource adequacy and transmission security requirements; therefore the LSR for an import-constrained zone is now the amount of capacity needed to satisfy "the higher of" either the (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 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 and the existing resources within the zone, including any proxy units that were added as a result of the

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

total system not meeting the LOLE criteria. 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 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. Further reduction in local sources 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 the New England Balancing Authority area (ISO-NE BA) 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 the ISO-NE BA.

d) Add proxy units, if required, within the ISO-NE BA 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 to be 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 BA 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 the ISO-NE BA.

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 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 Capability Year 2014/15. *Rest of New England* is used in the calculation of Maine MCL and includes all Load Zones with the exception of Maine.

Table 5: LRA Requirement Calculation Details (MW)

		Connecticut	NEMA/Boston	Rest of New England
$Resource_z$	[1]	9,505	3,943	33,127
Proxy $Units_z$	[2]	0	0	0
Surplus Capacity $Adjustment_z$	[3]	0	0	3,409
Firm Load $Adjustment_z$	[4]	1,935	1,275	-5
FOR_z	[5]	0.0653	0.0857	0.0618

Transmission Security Analysis (TSA) Calculation

The TSA is a deterministic reliability screen of an import-constrained area and is a security review set out in Section 3 of Planning Procedure No. 3, *Reliability Standards for the New England Area Bulk Power Supply System* and in Section 5.4 of Northeast Power Coordinating Council's (NPCC) Regional Reliability Reference Directory # 1, *Design and Operation of the Bulk Power System*. This review determines the requirement of the sub-area 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 and the results are presented in the form of a deterministic operable capacity analysis.

In accordance with ISO-NE Planning Procedure No. 3 and NPCC's Regional Reliability Reference Directory #1, this analysis includes evaluations of both (1) the loss of the most critical generator and the most critical transmission element (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 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.

Figure 5: Formula for TSA Calculation

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

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 in the Zone

Methodology for Calculating the TSA

The conditions used for TSA within the FCM are documented in Section 6 of ISO Planning Procedure No. 10, *Planning Procedure to Support the Forward Capacity*

Market.[16] The calculation of the ICR, LRA and TSA all rely on the same data set. However, due to the deterministic and transmission security-oriented nature of the TSA, some of the assumptions for completing the TSA 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 Load Zones for the 2014/15 Capability Year, whereas for LRA calculations, a distribution of loads covering the range of possible peak loads for that Capability Year is used. In addition, for the TSA, the forced outage of fast-start (peaking) generation is based on an assumed percentage instead of being based on historical five-year average performance. Finally, the load and capacity relief obtainable from actions of ISO-NE Operating Procedure No. 4 is not assumed within TSA calculations.

Local Sourcing Requirement (LSR)

The LSR for the Connecticut or NEMA/Boston Load Zone is the higher of the LRA requirement or TSA for the respective Load Zone. Table 6 summarizes the LRA and TSA for the Connecticut and NEMA/Boston Load Zones. As shown, the TSA is the highest requirement for each respective Load Zone. Therefore the LSR for the Connecticut and NEMA/Boston Load Zones are 7,478 MW and 3,046 MW, respectively. However, they will not be modeled as separate Capacity Zones in the FCA but rather as part of the Rest of the Pool Capacity Zone.

Table 6: LSR for the 2014/2015 Capability Year (MW)

Load Zone	Local Resource Adequacy Requirement	Transmission Security Analysis Requirement	Local Sourcing Requirement
Connecticut	7,434	7,478	7,478
NEMA/Boston	2,549	3,046	3,046

Maximum Capacity Limit (MCL) Calculation

To determine the MCL, the New England ICR and the LRA of the Rest of New England are needed. 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 the export-constrained zone.

The MCL for Maine includes capacity resource imports over the New Brunswick ties and also reflects the tie benefits assumed available over the New Brunswick ties. That is, the MCL is reduced to reflect the flows required to receive the assumed tie benefits from New Brunswick to assist the New England Balancing Authority area at the time of a

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

capacity shortage. Allowing more purchases of capacity from resources located in Maine could preclude the energy flows required to realize tie benefits.

For the Maine export-constrained transmission Load Zone, 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 the ISO-NE Balancing Authority 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 the ISO-NE Balancing Authority 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 the ISO-NE Balancing Authority area 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 rest of ISO-NE Balancing Authority 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 Balancing Authority area, which for the purposes of this calculation is treated as an import-constrained region, determined in accordance with Market Rule 1, Section III.12.2.1.

Table 7 shows the details of the MCL calculation for the 2014/15 Capability Year.

Table 7: MCL Calculation Details (MW)

		Maine
Net ICR for New England	[1]	33,200
$LRA_{RestofNewEngland}$	[2]	29,498
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,702**

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 models, for each of the six New England states, were estimated using 15 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 demand energy (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 appliance saturations. The base demand relationships are forecast to grow at the same rate as the associated energy forecast. The weather is represented by over 35 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, the New England Balancing Authority area's load is defined as the sum of the load of each of the six New England states, as 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. 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.

The overall New England and individual subarea load forecasts used in the calculation of ICR, LSR and MCL for the 2014/15 Capability Year are documented within the April 2010 *Forecast Report of Capacity, Energy, Loads and Transmission (CELT)*.[17]

Load Forecast Uncertainty

GE MARS models the load forecast using hourly chronological subarea loads and can include the effects of load forecast uncertainty by calculating the LOLE for up to ten different load levels and computing 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 for which to calculate the reliability indices. Each per unit multiplier represents a

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

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. The multipliers are allowed to vary by month.

The summer 2014 peak load forecast distribution is shown in Table 8. 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 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 of the GE MARS Model.

Table 8: Summer 2014 Peak Demand Forecast Distribution (MW)

10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
27,665	27,905	28,240	28,610	29,025	29,465	29,915	30,560	31,340	32,000

Existing Capacity Resources

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

(a) All Existing Generating Capacity Resources,

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

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

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

Section III.12.7.2 also states that the rating of the Existing Generating Capacity Resources, Existing Demand Resources and Existing Import Capacity Resources used in the calculation of the ICR and LSR shall be the summer Qualified Capacity value of such resources for the relevant Load Zone. The Qualified Capacity value will be based on a five-year median capacity rating for each resource. This year, Section (c), noted above, required that only Existing Import Resources with a multi-year contract could be modeled in the ICR calculation. Therefore, although 1,278.800 MW of import capacity was qualified as an Existing Import Capacity Resource, only 312.800 MW was modeled within the ICR calculation after excluding resources without multi-year contract(s) and reflecting the value of the firm import contract of the Vermont Joint Owners (VJO).

Summaries of resources categorized as Existing Capacity within the ICR, LSR and MCL calculations are provided in the sections below.[18] 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, LSR and MCL.

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 in the calculation. Existing Qualified Generating Capacity, by Load Zone, used within the ICR, LSR and MCL calculations were based on Qualified Existing Generating Resources for the 2014/15 Capability Year and is summarized in Table 10.

Table 9: Existing Qualified Generating Capacity by Load Zone (MW)

Load Zone	Summer
MAINE	3,004.048
NEW HAMPSHIRE	4,100.001
VERMONT	893.441
CONNECTICUT	7,993.822
RHODE ISLAND	2,624.615
SOUTH EAST MASSACHUSETTS	6,015.601
WEST CENTRAL MASSACHUSETTS	3,904.790
NORTH EAST MASSACHUSETTS & BOSTON	3,274.882
Total New England	**31,811.200**

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, LSR and MCL calculations were those that have Qualified as Existing Generating Resources for the 2014/15 Capability Year are shown in Table 10.

[18] For detailed data of Qualified Existing Resources used in the calculation of ICR-Related Values see: http://www.iso-ne.com/regulatory/ferc/filings/2010/may/er10-1182-000_05-04-10_4th_fca_info_filing.pdf

Table 10: Existing IPR by Load Zone (MW)

Load Zone	Summer	Winter
MAINE	261.068	348.702
NEW HAMPSHIRE	157.650	198.575
VERMONT	75.741	119.925
CONNECTICUT	414.569	428.405
RHODE ISLAND	5.889	8.209
SOUTH EAST MASSACHUSETTS	78.808	82.310
WEST CENTRAL MASSACHUSETTS	48.174	67.497
NORTH EAST MASSACHUSETTS & BOSTON	68.939	71.307
Total New England	**1,110.838**	**1,324.930**

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 versification analysis performed during the resource Qualification process.

Existing Demand Resources, by Load Zone, used within the ICR, LSR and MCL calculations are those that have Qualified as an Existing Demand Resource Capacity for the 2014/15 FCA, are shown in Table 11. These values are the Existing Qualified values that include the 8% Transmission and Distribution Gross-up.

Table 11: Existing Demand Resources by Load Zone (MW)

Load Zone	On-Peak	Seasonal Peak	Real-Time Demand Response	Real-Time Emergency Gen	Total
MAINE	112.206	-	311.220	35.023	458.449
NEW HAMPSHIRE	70.963	-	59.449	39.135	169.547
VERMONT	94.398	-	51.060	18.240	163.698
CONNECTICUT	122.044	301.055	370.481	300.301	1093.881
RHODE ISLAND	83.349	1.727	74.931	98.478	258.485
SOUTH EAST MASSACHUSETTS	130.221	1.727	165.573	78.637	376.158
WEST CENTRAL MASSACHUSETTS	116.486	30.420	169.213	101.193	417.312
NORTH EAST MASSACHUSETTS & BOSTON	236.207	-	285.866	143.624	665.697
Total New England	965.874	334.929	1487.793	814.631	3603.227

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 the firm contract(s) or any de-ratings due to Transmission Transfer Capability (TTC). If the amount of Qualified Import Capacity over a transmission interface is greater than the transmission interface limit, the capacity of the import being modeled within the ICR calculation is subsequently reduced to a value equal to that of the transmission interface limit. Table 12 shows the Existing Import Resources used within the ICR, LSR and MCL calculations, which were based on Qualified Existing Import Resources for the 2014/15 Capability Year minus any de-ratings due to submitted de-lists bid(s) reflecting the firm value of import contracts and any import resources without multi-year contracts.

Table 12: Existing Import Resources (MW)

Resource Name	Interface	Summer Qualified Capacity	Import Capacity Modeled in ICR
NYPA - CMR	NY AC Ties	68.800	68.800
NYPA - VT	NY AC Ties	11.000	11.000
VJO - Highgate	HQ Highgate	212.000	194.000
VJO - Phase I/II	Phase I/II	50.000	39.000
Lievre River Project - Import	Phase I/II	240.000	-
Erie Boulevard Hydropower - Import	NY AC Ties	697.000	-
Total Imports		1278.800	312.800

For the 2014/15 ICR calculation, several de-rates were applied to the Vermont Joint Owners (VJO) imports to reflect the value of the firm contract. An 18 MW de-rate was modeled for the VJO import delivered over the Highgate facilities, an 11 MW de-rate was applied to the VJO import delivered over the Phase II facilities, and a 40 MW de-rate was applied to the Block Load, which qualified as an Existing Capacity Resource at 60 MW. In addition, two imports which qualified as Existing, yet did not have multi-year contracts, were not modeled within the ICR calculation.[19]

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. Only one export of capacity was modeled within the ICR, LSR and MCL assumptions. This is the 100 MW sale to the Long Island Power Authority (LIPA) over the Cross-Sound Cable, which is modeled as decreased capacity from the unit-specific resource supplying the export.

New Capacity Resources

Market Rule 1, Section III.12.7.2 describes the capacity resources to be modeled within the ICR 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.

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 interface for the Capability Year 2014/15. Although external transmission transfer capability is not currently 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 limits are used in the determination of the LSR and MCL.

External Transmission Transfer Capability

Table 13 shows the External Transmission Transfer Capabilities that were used within the tie benefits study and was used by ISO-NE within the 2014/15 FCA.

Table 13: External Transmission Transfer Capability (MW)

Interface: Canada & New York to New England	Summer Limit
Hydro-Quebec to New England (Highgate)	200
Hydro-Quebec to New England (Phase II)	1,400
New Brunswick to New England	700
New York to New England (AC Interface)	1,400
New York to New England (Cross Sound Cable DC Interface)	0

[19] See Market Rule 1, Section III.12.7.2 (c): http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_sec_1_12.pdf

Internal Transmission Transfer Capability

For the 2014/15 FCA, ISO-NE evaluated three Load Zones relating to their LRA requirement and MCL, 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.

Table 14 shows the N-1 Internal Transmission Transfer Capability for the CT and NEMA/Boston Load Zones as used in the calculation of LRA requirement, and the ME Load Zone as used in the calculation of MCL. In addition, the N-1-1 Transfer Capability is also an input into the TSA analysis for Connecticut and NEMA/Boston and is shown in Table 14.

Table 14: Transmission Transfer Capability (MW)

Interface	N-1 Limit	N-1-1 Limit
Connecticut Import	2,600	1,400
NEMA/Boston Import	4,900	3,700
Maine-New Hampshire	1,600	-

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-NE Operating Procedure No. 4 – *Action During a Capacity Deficiency* (OP4) is that EOP for New England. In other words, load and capacity relief assumed obtainable from implementing certain OP4 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 reductions, and capacity available from the dispatch of Real-Time Emergency Generation (RTEG) all constitute actions that ISO-NE System Operators can invoke under OP4 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

Tie benefits reflect the amount of emergency assistance that is assumed will be available to New England from its neighboring Balancing Authority areas, without jeopardizing reliability in New England or its neighboring Balancing Authority areas, in the event of a capacity shortage in New England.

In calculating the ICR-Related Values for the 2014/15 Capability Year, ISO-NE used for the first time revised procedures for calculating tie benefits, which are an input into the determination of the Installed Capacity Requirement and related values. These revised procedures are reflected in Section III.12.9 of Market Rule 1, and were filed by ISO-NE on December 30, 2010, and accepted by the Commission in an order dated February 28, 2011.[20,21] The tie benefits calculation methodology has been revised to include (1) the modeling of transmission constraints internal to New England and its neighboring Balancing Authority areas that impact the ability of neighboring Balancing Authority areas to provide emergency assistance to New England and the ability of New England to make use of that emergency assistance, (2) changes to the manner in which capacity imports are accounted for in the tie benefits calculation, and (3) the calculation of tie benefits for individual interconnections, in addition to 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 and New York.

The tie benefits study for the 2014/15 Capability Year was conducted using the probabilistic GE MARS program to model the expected system conditions of New England and its directly interconnected neighboring Balancing Authority areas of Québec, New Brunswick and New York. During the modeling, these Balancing Authority areas were assumed to be *At-Criteria*, which means that the capacity of all three neighboring Balancing Authority areas was adjusted so that they would each have a LOLE of once in ten years (0.1 days per year LOLE).

Total Tie Benefits

Total tie benefits were calculated using the results of a probabilistic analysis that determines LOLE indices for the New England system and surrounding Balancing Authority areas. LOLE calculations were first done on an interconnected basis that included all existing connections (tie lines) between New England's directly connected neighboring Balancing Authority areas. This established the minimum amount of capacity that each Area needed in order to attain the NPCC resource adequacy requirements of 0.1 days per year LOLE.

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

Based on the methodology described above, a total of 1,689 MW of tie benefits are assumed within the ICR calculations for the 2014/15 Capability Year.

[20] Filing available at: http://www.iso-ne.com/regulatory/ferc/filings/2010/dec/er11-2580-000_12-30-10_tie_benefits.pdf
[21] Order available at: http://www.iso-ne.com/regulatory/ferc/orders/2011/feb/er11-2580-000_2-28-11_order_tie_benefits.pdf

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 New England, 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 2014/15 Capability Year, the individual Balancing Authority area tie benefits were calculated as 960 MW for Québec, 439 MW for New Brunswick, and 290 MW for New York.

Individual Connection(s) Tie Benefits

Revisions to the tie benefits calculations call 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 New England, 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 tie benefits result.

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 2014/15 Capability Year, individual interconnection tie benefits were determined from Québec over the HQ Phase II facility of 954 MW, 6 MW from Québec over the Highgate facility, 290 MW of the New York tie benefits are delivered over the New York AC ties and 0 MW from the Cross-Sound Cable.

Hydro-Québec Interconnection Capability Credits (HQICCs)[22]

Hydro-Québec Interconnection Capability Credits, or HQICCs, are a preferential allocation of the total New England tie benefit to the Interconnection Rights Holders (IHR), which are regional entities that hold certain rights over the Hydro-Québec Interconnection. These rights are monetized as credits in the form of reduced capacity requirements.

[22] The 2014/15 Capability Year HQICCs values were filed with the Commission in the 2014/15 ICR filing: http://www.iso-ne.com/regulatory/ferc/filings/2011/mar/er11-3048-000_03-08-11_icr_2014-2015.pdf

The HQICC values are 954 MW as determined by the tie benefits from Québec over the Phase II facility, and are applicable for every month during the 2014/15 Capability Year.

5% Voltage Reduction

Under the Forward Capacity Market, load reduction from implementation of 5% voltage reductions is also used in the development of the ICR-Related Values. This constitutes an action that ISO-NE System Operators invoke in real-time under Operating Procedure No. 4, to balance system supply with demand under actual or expected capacity shortage conditions.

The amount of load relief assumed obtainable from invoking 5% voltage reductions 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). 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."*

This assumption uses the benchmark 1.5% load relief value specified in Appendix A of Operating Procedure No. 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 as was used in prior ICR calculations.

The voltage reduction load relief values assumed as offsets against the Installed Capacity Requirement are calculated as the 1.5% assumption times the 50-50 peak load forecast after accounting for the amount of passive demand resources, which as assumed to be already implemented and therefore not contributing to the 1.5% reduction in load. For the 2014/15 ICR calculation, the demand relief obtainable from a 5% voltage reduction is calculated as:

Table 15 shows the amount of voltage reduction (MW) modeled as OP 4 load relief of Actions 6 & 8 for each of the months of the 2014/15 Capability Year within the ICR calculations.

Table 15: OP 4 Action 6 & 8 Modeled (MW)

	Peak Load	Passive DR	Action 6 & 8 5% Voltage Reduction
Jun - Sep	29,025	1,301	416
Oct - May	22,505	1,283	318

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

Table 16: Summary of Resource and OP 4 Assumptions (MW)

Type of Resource	Summer	Winter
Generating Resources	31,811.200	31,811.200
Intermittent Power Resources	1,110.838	1,324.930
Demand Resources	3,603.227	3,603.227
Import Resources	312.800	312.800
OP 4 Voltage Reduction	416.000	318.000
Minimum Operating Reserve	(200.000)	(200.000)
Tie Benefits Including 954 MW of HQICCs	1,689.000	1,689.000
Total MW Modeled in ICR	**38,743.065**	**38,859.157**

Availability

Generating Resource Forced Outages

A five year, historical average of unit-specific forced outage assumptions is determined for each generating unit that qualified as an Existing Generating Capacity Resource, using the most recent available data of monthly Equivalent Forced Outage Rate -

Demand (EFORd) values from NERC's Generating Availability Data System (GADS).[23] The NERC GADS data, submitted by regional generators to ISO-NE for the months of September 2005 through August 2010, 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 17 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 an input assumption.

Generating Resource Scheduled Outages

A weekly representation of a generator's scheduled 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. A single value is then calculated for each unit, based on a five-year historical average. In addition to the EFORd data, Table 17 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.

Table 17: 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	11,407	4.2	5.3
Fossil	9,421	7.7	4.3
Nuclear	4,630	1.8	3.0
Hydro (Includes Pumped Storage)	3,073	3.0	3.3
Combustion Turbine	2,915	6.7	1.9
Diesel	232	6.7	1.0
Miscellaneous	133	14.4	1.2
Total System	31,811	5.1	4.1

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 ratings, these resources are assumed 100% available within the ICR model.

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

Demand Resources Availability

Passive Demand Resources

Table 18 tabulated the Passive Demand Resources in the On-Peak and Seasonal Peak categories of Demand Resources. These resources are considered as 100% available within the ICR model. These two categories consist of passive resources such as energy efficiency, which are considered always "*in service*" and as such, are subsequently assumed to be 100% available.

Table 18: Passive Demand Resources – Summer (MW) and Performance (%)

Load Zone	On-Peak		Seasonal Peak	
	MW	Availability (%)	MW	Availability (%)
MAINE	112.206	100	-	-
NEW HAMPSHIRE	70.963	100	-	-
VERMONT	94.398	100	-	-
CONNECTICUT	122.044	100	301.055	100
RHODE ISLAND	83.349	100	1.727	100
SOUTH EAST MASSACHUSETTS	130.221	100	1.727	100
WEST CENTRAL MASSACHUSETTS	116.486	100	30.420	100
NORTH EAST MASSACHUSETTS & BOSTON	236.207	100	-	-
Total New England	965.874	100	334.929	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.

The historical performance metric used for the 2014/15 FCA ICR calculation was the same assumption discussed and developed by the PSPC for the 2013/14 FCA ICR calculation.[24] This performance metric incorporates both OP 4 and audit events for the period of 2005 – 2009 and includes resources participating in the current Load Response program. While Demand Resource performance results were available for summer 2010 OP 4 and audit events, due to the preliminary nature of the data, the PSPC agreed with the recommendation by ISO-NE to wait until the Demand Resource performance results had gone through the full ISO Settlement process before attempting to incorporate the results into the Demand Resource performance data used within the ICR calculation. Therefore, for the 2014/15 ICR calculation, there were no changes made to the availability values calculated for the 2013/14 ICR calculation.

---

[24] See http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2010/feb182010/dr_performance_fca4_2_18_2010.pdf for a detailed discussion of this topic.

The results of this calculation and the performance rates for Active Demand Resources modeled within the ICR calculation for each of the Load Zones are shown in Table 19.

Table 19: Demand Response Resources Summer (MW) and Performance (%)

Load Zone	RT Demand Response		RT Emergency Gen	
	MW	Availability (%)	MW	Availability (%)
MAINE	311.220	100	35.023	100
NEW HAMPSHIRE	59.449	74	39.135	74
VERMONT	51.060	99	18.240	45
CONNECTICUT	370.481	76	300.301	87
RHODE ISLAND	74.931	48	98.478	17
SOUTH EAST MASSACHUSETTS	165.573	56	78.637	58
WEST CENTRAL MASSACHUSETTS	169.213	67	101.193	72
NORTH EAST MASSACHUSETTS & BOSTON	285.866	72	143.624	87
Total New England	1487.793	76	814.631	73

Difference from 2013/14 FCA ICR-Related Values

Change in ICR

In an effort to quantify the effects that each input assumption has on the determination of ICR, ISO-NE began with the input assumptions associated with the ICR calculated for the 2013/14 Capability Year and incrementally substituted each assumption with the corresponding 2014/15 Capability Year 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 20 lists the assumptions for each study year and their subsequent effect on the resultant ICR value.

Table 20: Summary of ICR Input Assumptions for 2013/14 vs. 2014/15

Assumption	2013/2014 FCA		2014/2015 FCA		Effect on ICR (MW)
Tie Benefits	194 MW New York		290 MW New York		45
	584 MW Maritimes		439 MW Maritimes		
	916 MW Quebec (HQICCs)		954 MW Quebec (HQICCs)		
	6 MW Quebec via Highgate		6 MW Quebec via Highgate		
Total	1,700 MW		1,689 MW (Case 1)		
	MW	Weighted Forced Outage (%)	MW	Weighted Forced Outage (%)	
Demand Resources	3,130	17.0	3,603	15.9	-1
Generation	31,629	4.8	31,811	5.1	65
IPR	1,086	0	1,111	0	-9
Imports & Sales	1,114	3.4	212.8	0.3	47
	MW		MW		
Load Forecast	28,570		29,025		547
Updated Skewness Model					387
WH vs. MARS Difference					12
	MW	%	MW	%	
OP 4 5% VR	413	1.5	416	1.5	-9
ICR	33,043		34,154		1,111

As shown in Table 20, the assumption with the greatest affect on ICR is the increase in the forecasted load when going from the 2013/14 Capability Year to the 2014/15 Capability Year. Since both ICR calculations used the 2010 CELT load forecast, the increase in the load forecast is simply the annual projected load growth and not due to a change in load forecast assumptions or methodology.

A change was made to the ALCC methodology to correct the calculation to include the skewness portion of the distribution.[25] This change accounts for the second largest effect on the ICR results because of the amount of surplus capacity. The skewness component has minimal impact on ALCC when the installed resource base is close to the one day in ten requirement.

[25] For a more detailed discussion of this issue see: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2010/may272010/a3_modification_alcc_formula.ppt

The impact of not assuming skewness in ALCC calculations is that ICR-Related Values are understated under conditions of capacity surplus and overstated during conditions of capacity shortage.

When all resource assumptions are updated, including the load forecast, OP 4 and resource rating and availability assumptions, the ICR for the 2014/15 Capability Year is 1,111 MW or 3.4% higher than the ICR value for the 2013/14 Capability Year, driven primarily by the change in load forecast and ALCC methodology.

Change in LRA Requirement

Table 21 shows the difference in the assumptions and results of the 2014/15 LRA requirement calculation, as compared to the 2013/14 LRA requirement calculations for the import-constrained CT, NEMA/Boston load zones and the Rest of New England.

Table 21: Summary of Changes in LRA Requirement for 2013/14 vs. 2014/15

Local Resource Adequacy Requirement		2013/14 FCA	2014/15 FCA	2013/14 FCA	2014/15 FCA	2013/14 FCA	2014/15 FCA
		Connecticut		NEMA/Boston		Rest_of_NewEngland	
$Resource_z$ MW	[1]	9,337	9,505	3,960	3,943	33,338	33,127
Proxy $Units_z$ MW	[2]	0	0	0	0	0	0
Surplus Capacity $Adjustment_z$ MW	[3]	0	0	0	0	4535	3409
Firm Load $Adjustment_z$ MW	[4]	1,950	1,935	1,290	1,275	-100	-5
FOR_z %	[5]	5.83	6.53	8.59	8.57	5.86	6.18
LRA_z MW	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**7,266**	**7,434**	**2,549**	**2,549**	**28,940**	**29,498**

Change in MCL

Table 22 shows the difference in the assumptions and results of the 2014/15 MCL calculation, as compared to the 2013/14 MCL calculation for the Maine Load Zone.

Table 22: Summary of Differences in MCL for 2013/14 vs. 2014/15 for ME (MW)

Maximum Capacity Limit		2013/14 FCA	2014/15 FCA
		Maine	
Net ICR for New England	[1]	32,127	33,200
$LRA_{RestofNewEngland}$	[2]	28,940	29,498
Maximum Capacity $Limit_Y$	[3]=[1]-[2]	**3,187**	**3,702**

Table 23 shows the summary comparison between the all the ICR-Related Values calculated for the 2014/15 FCA versus the 2013/14 FCA.

Table 23: Summary of Changes to ICR-Related Values (MW)[26]

	New England		Connecticut		NEMA/Boston		Maine	
	2013/14 FCA	2014/15 FCA	2013/14 FCA	2014/15 FCA	2013/14 FCA	2014/15 FCA	2013/14 FCA	2014/15 FCA
Peak Load (50/50)	28,570	29,025	7,485	7,585	5,730	5,805	2,145	2,185
Total Resources	36,959	36,838	9,337	9,505	3,960	3,943	3,621	3,712
Installed Capacity Requirement	33,043	34,154						
NET ICR (ICR Minus HQICCs)	32,127	33,200						
Local Sourcing Requirement			7,419	7,478	2,957	3,046		
Maximum Capacity Limit							3,187	3,702

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

{ End of Report }