



# ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2011/12 Capability Year

ISO New England Inc.  
December 1, 2008

# ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Maximum Capacity Limit for the 2011/12 Capability Year

## Executive Summary

As part of the Forward Capacity Market, ISO New England (the ISO) is preparing to conduct the second Forward Capacity Auction for the 2011/12 Capability Year. The auction, which will be conducted on December 8, 2008, will be to satisfy the resource adequacy obligations of all New England market participants within the six state footprint of the ISO.<sup>1</sup> In this report, the ISO is documenting the results and assumptions of the 2011/12 Capability Year Installed Capacity Requirement (ICR), Local Sourcing Requirements (LSR), and Maximum Capacity Limit (MCL) values – all of which are key inputs in the Forward Capacity Auction – and Hydro Québec Interconnection Capability Credits (HQICCs), which are a key input into the calculation of the Installed Capacity Requirement.

The ICR is a measure of the installed resources that are projected to be necessary to meet adequacy standards in light of total forecasted load requirements for the New England Control Area and to maintain sufficient reserve capacity from a resource adequacy perspective. More specifically, the ICR is the amount of resources needed to meet the planning reliability requirements defined for the New England Control Area such that the probability of disconnecting non-interruptible customers (a loss of load expectation or “LOLE”) no more than once every ten years (an LOLE of 0.1 days per year). The methodology for calculating the ICR is set forth in Section III.12 of Market Rule 1. The ICR for the 2011/12 Capability Year is the amount of installed capacity to be procured in the Forward Capacity Auction that will be held in December 2008.<sup>2</sup> The values for this year’s ICR, as in previous years, are based on three essential components: the load forecast, unit availability, and tie benefits. The methodologies for determining projected load and resource outage rates are the same as those used in previous years, albeit adjusted due to the need under the new Forward Capacity Market to project the ICR three years in advance.<sup>3</sup>

---

<sup>1</sup> The December 8, 2008 Forward Capacity Auction, like future Forward Capacity Auctions, will be conducted in advance of the Capability Year in which the capacity will actually be supplied. The December 2008 Forward Capacity Auction applies to a supply commitment period that corresponds to the 2011/12 Capability Year (*i.e.*, June 1, 2011 to May 31, 2012). Resources that clear in the Forward Capacity Auction will be obligated to supply capacity to the New England Control Area during the 2011/12 Capability Year and load-serving entities will be obligated to pay for the capacity procured.

<sup>2</sup> Pursuant to Section III.13 of Market Rule 1, the ISO administers the Forward Capacity Auction in order “to procure the amount of capacity needed in the New England Control Area.”

<sup>3</sup> See, *e.g.*, *ISO New England Inc.*, 111 FERC ¶ 61,185, *reh’g denied*, 112 FERC ¶ 61,254 (2005), *appealed on jurisdictional grounds*, *Conn. Dept. of Pub. Util. Control v. FERC*, 484 F.3d 558 (D.C. Cir. 2007), *reh’g denied*, 2007 U.S. App. LEXIS 17020 (July 13, 2007), *mandate issued* (July 27, 2007), *on remand to*, 122 FERC P 61, 144 (2008), *reh’g denied*, 122 FERC ¶ 61, 036 (2008) (2005/2006 Capability Year Installed Capacity Requirements); and *ISO New England Inc.*, 119 FERC ¶ 61,161 (2007), *reh’g*

This report documents the New England Control Area’s ICR, LSR and MCL (collectively the “*ICR Values*”) as calculated by ISO New England for the 2011/12 Capability Year. The 2011/12 is the second Capability Year of the FCM and begins on June 1, 2011 and terminates on May 31, 2012. In addition, this report details all the assumptions and calculations that were used to develop these ICR Values for the 2011/12 Capability Year.

New England’s load, resources and other assumptions needed for calculating the 2011/12 Capability Year ICR Values were developed by the ISO with extensive stakeholder input and review through meetings of the NEPOOL Power Supply Planning Committee (PSPC). As approved by the Federal Energy Regulatory Commission (FERC) in its docket No. ER07-365, the ISO followed the methodology outlined in Market Rule 1, Section III.12.1 for calculating ICR and Market Rule 1, Section III.12.2 for calculating the LSR and MCL. The ISO has determined the ICR Values tabulated in Table 1 for the 2011/12 Capability Year.

**Table 1: Summary of 2011/12 ICR Values (MW)<sup>4</sup>**

2011/12	NEW ENGLAND	CONNECTICUT	NEMA/Boston	MAINE
Load (50/50)	29,405	7,750	5,815	2,205
Assumed Existing Resources	35,667	8,189	3,753	3,571
ICR	33,439			
LSR		6,817	2,016	
MCL				3,395

As in past years, the ISO developed the initial ICR Values with stakeholder input which is provided in part through the NEPOOL committee processes through review by the PSPC, the Reliability Committee (RC) and the Participants Committee (PC). All of the load and resource assumptions needed for the Westinghouse/ABB Capacity Model Program (Capacity Model) were reviewed by the PSPC, a subcommittee of the RC. The ISO, in consultation with NEPOOL and other interested parties, developed the proposed ICR Values for the 2011/12 Capability Year through an extensive stakeholder process which involved more than 13 meetings during a period of 8 months. The ISO used the methodologies and assumptions for determining the ICR Values that are set out in Section III.12 of Market Rule 1, which were approved by the Commission early last

---

*denied*, 121 FERC ¶ 61, 125 (2007) (2007/2008 Capability Year Installed Capacity Requirements). *See also* 2010/2011 ICR Order; *order on reh’g*, 123 FERC ¶ 61,129 (2008).

<sup>4</sup> 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 911 MW of HQICCs that are allocated to the Interconnection Rights Holders (IHR), is 32,528 MW.

year.<sup>5</sup> The methodology and assumptions used to calculate the ICR Values also are consistent with the approach reflected in the recent capacity requirement values submitted (and accepted) to the FERC for previous Capability Years.<sup>6</sup> There was broad agreement regarding many of the assumptions, inputs and projections for calculating the 2011/12 Capability Year ICR Values.

The RC at its July 21, 2008 meeting reviewed and considered the outcome of the PSPC's efforts with respect to the development of the 2011/12 ICR Values. A motion to recommend that the RC recommend that the PC support the ISO's proposed ICR Values that are the subject of this report failed to pass (54.55% vote in favor). At its August 1, 2008 meeting, a motion that the PC support these proposed ICR Values also failed to pass (59.97% vote in favor). As a general matter, during the stakeholder process there were some stakeholders that supported a higher Installed Capacity Requirement and some that supported a lower requirement. .

---

<sup>5</sup> *ISO New England Inc. and New England Power Pool*, 118 FERC ¶ 61,157 (2007), *reh'g denied*, 120 FERC ¶ 61,234 (2007) (the "ICR Rules Order"), *appeal docketed, Connecticut Department of Public Utility Control v. Federal Energy Regulatory Commission*, Case No. 07-1375 (D.C. Cir. September 21, 2007). That appeal challenges the Commission's jurisdiction to oversee establishment of the Installed Capacity Requirement, but does not challenge either: (1) the actual technical provisions of the market rules reflected in Section III.12 of the ISO Tariff that were approved by the Commission in that order and that were used to calculate the Installed Capacity Requirements and related values that are the subject of this filing; or (2) any particular set of these values that have been submitted to the Commission.

<sup>6</sup> *See, e.g.*, 119 FERC ¶ 61,161; 111 FERC ¶ 61,185

# Table of Contents

Executive Summary .....	1
Table of Contents .....	4
List of Tables .....	6
List of Figures .....	7
Introduction.....	8
ICR Values for 2011/12.....	10
Installed Capacity Requirement for 2011/12 .....	10
Local Sourcing Requirements for 2011/12 .....	10
Maximum Capacity Limit for 2011/12 .....	11
Methodology.....	11
Reliability Planning Model for ICR.....	11
Reliability Planning Model for LSR and MCL.....	12
Installed Capacity Requirement Calculation .....	12
Local Sourcing Requirements Calculation .....	13
Maximum Capacity Limit Calculation .....	15
Assumptions.....	16
Load Forecast.....	17
Load Forecast as Modeled in the Westinghouse Capacity Model.....	17
Load Forecast as Modeled in the GE MARS Model .....	19
Existing Capacity .....	19
Generating Resources .....	20
Intermittent Power Resources .....	21
Demand Resources.....	22
Import Resources .....	24
Sales .....	25
New Capacity Resources .....	25
De-Listed Capacity Resources .....	25
Transmission Transfer Capability.....	25
External Transmission Transfer Capability .....	25
Internal Transmission Transfer Capability .....	26
Tie Benefits.....	26
Total Tie Benefits .....	28
Individual Control Area Tie Benefits .....	28
Hydro-Québec Interconnection Capability Credits .....	29
OP 4 Load Relief .....	29
Operating Reserve.....	30
Availability .....	30
Generating Resource Forced Outages.....	30
Generating Resource Scheduled Outages .....	31
Intermittent Power Resource Availability .....	32
Demand Resources Availability .....	32
Proxy Units .....	34
Difference from 2010/11 ICR Values.....	35

Conclusions..... 38

## List of Tables

Table 1: Summary of 2011/12 ICR Values (MW).....	2
Table 2: ICR Calculation Details (MW).....	13
Table 3: LSR Calculation Details (MW) .....	15
Table 4: MCL Calculation Details (MW).....	16
Table 5: Summary of Input Assumptions .....	16
Table 6: Value of Input Assumptions (MW).....	17
Table 7: Summer 2011 Peak Load Forecast Distribution (MW).....	18
Table 8: Existing Qualified Generating Capacity by Load Zone (MW) .....	21
Table 9: Existing IPR Resources by Load Zone (MW).....	22
Table 10: Existing Demand Resources by Load Zone (MW).....	23
Table 11: Existing Import Resources (MW).....	24
Table 12: External Transmission Transfer Capability Limits (MW).....	26
Table 13: Internal Transmission Transfer Capability Limits (MW).....	26
Table 14: Spring and Fall 2007 OP 4 Voltage Reduction Test Results (%).....	30
Table 15: OP 4 Action 12 & 13 Modeled (MW).....	30
Table 16: Generating Resource EFORd and Maintenance Weeks by Category .....	32
Table 17: Passive Resource – Summer MW and Performance % .....	33
Table 18: Demand Response Resources Summer MW and Performance %.....	34
Table 19: Real-Time Emergency Generators - Summer MW and Performance % .....	34
Table 20: Summary of ICR Input Assumptions for 2011/12 and 2010/11 .....	36
Table 21: Summary of Differences in 2011/12 & 2010/11 LSR for CT (MW) .....	36
Table 22: Summary of Differences in 2011/12 & 2010/11 LSR for NEMA/Boston (MW) .....	37
Table 23: Summary of Differences in 2011/12 & 2010/11 LSR for Rest-of-New England (MW) (Used in ME MCL Calculation) .....	37
Table 24: Summary of Differences in 2011/12 and 2010/11 MCL for ME .....	37

## List of Figures

Figure 1: Formula for ICR Calculation.....	12
Figure 2: Formula for LSR Calculation .....	14
Figure 3: Formula for MCL Calculation.....	15
Figure 4: 95th Percentile of the Weekly Peak Load Forecast Distribution .....	18
Figure 5: Forecasted New England Hourly Load Duration Curve for 2011/12 .....	19

## Introduction

The Installed Capacity Requirement (ICR) is an ISO-projected measure of the capability that is necessary to satisfy the resource adequacy requirements of ISO New England's (the ISO) Control Area's forecasted electrical peak load requirements, which also includes sufficient reserve capacity to meet regional planning reliability standards. More specifically, ICR is the amount of capacity needed to meet the requirements defined for the New England Control Area such that the probability of disconnecting non-interruptible customers (a loss of load expectation or "LOLE") 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 Operating Procedure No. 4 – *Actions During a Capacity Deficiency* (OP 4).

Under the mandates of the Forward Capacity Market (FCM), Market Rule 1, Section III.12.1 states that *"prior to each Forward Capacity Auction, the ISO shall calculate the ICR for the New England Control Area for each upcoming Capability Year through the Capacity Commitment Period associated with that Forward Capacity Auction in accordance with this Section III.12.1."*<sup>7</sup>

In addition to the ICR, the ISO also calculates the Local Sourcing Requirement (LSR) and Maximum Capacity Limit (MCL) according to Market Rule 1, Section III.12.2 which states that *"prior to each Forward Capacity Auction, the ISO shall calculate the capacity requirements and limitations, accounting for relevant transmission interface limits which shall be determined pursuant to Section III.12.5, for each Load Zone for each upcoming Capability Year through the Capacity Commitment Period associated with that Forward Capacity Auction. The Local Sourcing Requirement shall represent the minimum amount of capacity that must be electrically located within an import-constrained Load Zone. The Maximum Capacity Limit shall represent the maximum amount of capacity that can be procured in an export-constrained Load Zone to meet the Installed Capacity Requirement."*

ICR, LSR and MCL (collectively the "ICR Values") for the Capability Year 2011/12 (June 1, 2011 – May 31, 2012) were developed by the ISO in conjunction with stakeholder input. All load and resource assumptions needed for input by the Westinghouse/ABB Capacity Model Program (Capacity Model) for calculating ICR and the General Electric Multi-Area Reliability Simulation Program (GE MARS) for calculating LSR and MCL were compiled by the ISO and reviewed by the NEPOOL Power Supply Planning Committee (PSPC), a technical committee that is a standing subcommittee of the Reliability Committee (RC).

---

<sup>7</sup> Market Rule 1, Section III referenced in this report can be found at this link: [http://www.iso-ne.com/regulatory/tariff/sect\\_3/index.html](http://www.iso-ne.com/regulatory/tariff/sect_3/index.html).

The ICR Values for the 2011/12 Capability Year were determined using well established modeling methods and system modeling assumptions regarding a variety of factors, including forecast load, unit availability and tie reliability benefits. During the development of last year's ICR Values (for the 2010/2011 Capability Year), the ISO's recommendations resulted in consensus agreement during the stakeholder process regarding nearly all of the assumptions and modeling methods that are used to establish the ICR Values that are reflected in this report. However, there were two exceptions to the general consensus, which involved: (1) the method to be used to calculate total tie benefits; and (2) the manner in which total tie benefits are allocated to individual ties, which could impact the capacity obligations of certain market participants. The two issues involved whether and how, in the calculation and allocation of total tie benefits, the Commission-ordered deterministic calculation of HQICCs should be reflected.

As a result of a six-month stakeholder review conducted after the Commission's order on last year's filing, the ISO and NEPOOL in the July 31st Filing in Docket No. ER08-41-002 submitted changes to Market Rule 1 concerning the methodologies for calculating and allocating tie benefits with neighboring Control Areas. As described further below, the ISO adopted the methodology for calculating and allocating total tie benefits that was introduced in the July 31st Filing in the instant filing of the proposed ICR Values for the 2011/12 Capability Year, in response to the Commission's directive issued in its 2010/2011 ICR Order.

As in past years, the ISO developed the initial ICR recommendation with stakeholder input which is provided in part through the NEPOOL committee processes through review by the PSPC, the RC and the Participants Committee (PC). All of the load and resource assumptions needed for the Westinghouse/ABB Capacity Model Program ("Capacity Model") were reviewed by the PSPC, a subcommittee of the RC through an extensive stakeholder process which involved more than 13 meetings during a period of 8 months. The ISO used the methodologies and assumptions for determining the ICR Values that are set out in Section III.12 of Market Rule 1, which were approved by the Commission early last year.<sup>8</sup> The methodology and assumptions used to calculate the ICR also are consistent with the approach reflected in the recent capacity requirement values submitted (and accepted) for previous Capability Years.<sup>9</sup> There was broad agreement regarding many of the assumptions, inputs and projections for calculating the 2011/12 Capability Year ICR Values, however, concern was raised by some members that the level of capacity credit applied to Demand Resources in the Forward Capacity

---

<sup>8</sup> *ISO New England Inc. and New England Power Pool*, 118 FERC ¶ 61,157 (2007), *reh'g denied*, 120 FERC ¶ 61,234 (2007) (the "ICR Rules Order"), *appeal docketed*, *Connecticut Department of Public Utility Control v. Federal Energy Regulatory Commission*, Case No. 07-1375 (D.C. Cir. September 21, 2007). That appeal challenges the Commission's jurisdiction to oversee establishment of the Installed Capacity Requirement, but does not challenge either: (1) the actual technical provisions of the market rules reflected in Section III.12 of the ISO Tariff that were approved by the Commission in that order and that were used to calculate the Installed Capacity Requirements and related values that are the subject of this filing; or (2) any particular set of these values that have been submitted to the Commission.

<sup>9</sup> *See, e.g.*, 119 FERC ¶ 61,161; 111 FERC ¶ 61,185

Auction would result in under-procurement of capacity absent an adjustment (increase) to the ICR.<sup>10</sup>

The RC at its July 21, 2008 meeting reviewed and considered the outcome of the PSPC's efforts with respect to the development of the 2011/12 Capability Year ICR Values. A motion to recommend that the RC recommend PC support of the ISO's proposed ICR Values failed to pass (54.55% vote in favor). At its August 1, 2008 meeting, a motion that the PC support these proposed ICR Values also failed to pass (59.97% vote in favor). As a general matter, during the stakeholder process there were some stakeholders that supported a higher ICR and some that supported a lower requirement.

The ISO subsequently filed the ICR, LSR and MCL for the 2011/12 Capability Year with the FERC in September 2008.<sup>11</sup>

## ICR Values for 2011/12

### Installed Capacity Requirement for 2011/12

The ISO has calculated the ICR for the second Forward Capacity Auction (FCA) as 33,439 MW in accordance with Market Rule 1, Section III.12.1, which details the methodology for calculating ICR. The 33,439 MW ICR value for the 2011/12 Capability Year accounts for tie benefits (emergency energy assistance) assumed obtainable from the neighboring systems of the Maritimes and New York, but it does not reflect a reduction in capacity requirements relating to the assumed 911 MW of Hydro-Québec Interconnection Capability Credits (HQICCs) that are allocated to the Interconnection Rights Holders (IHR). The net amount of capacity to be purchased in the second FCA to meet the ICR, after deducting the 911 MW of interconnection capability credit associated with HQICCs, is 32,528 MW.

### Local Sourcing Requirements for 2011/12

The ISO has calculated all LSR in accordance with the methodology outlined in Market Rule 1, Section III.12.2.1 for the Connecticut (CT) Load Zone as 6,817 MW and LSR for the NEMA/Boston Load Zone as 2,016 MW. In the ISO's August 29, 2008 filing (ER08-1513-000) with the FERC<sup>12</sup>, the ISO reported that due to pending transmission reinforcements to these import constrained sub-areas, neither the Connecticut nor NEMA/Boston Load Zones will be modeled as separate zones within the second Forward Capacity Auction.

---

<sup>10</sup> [http://www.iso-ne.com/regulatory/ferc/filings/2008/oct/er09-209-000\\_10-31-08\\_dr\\_gross-up\\_filing.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2008/oct/er09-209-000_10-31-08_dr_gross-up_filing.pdf).

<sup>11</sup> A copy of the filing is available [http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000\\_9-9-08\\_2011-2012\\_icr\\_filing.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1512-000_9-9-08_2011-2012_icr_filing.pdf).

<sup>12</sup> The LSR values are used to determine whether separate zones must be modeled in the Forward Capacity Auction. The November 6, 2007 "Informational Filing for Qualification in the Forward Capacity Market" with the FERC, regarding numerous inputs into the Forward Capacity Auction as required by Section III.13.1 of the ISO Tariff, reported that Connecticut and NEMA/Boston will not be modeled as separate Capacity Zones in the second FCA. A copy of this filing can be found at [http://www.iso-ne.com/regulatory/ferc/filings/2007/nov/er08-190-000\\_11-06-07\\_informational\\_filing.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2007/nov/er08-190-000_11-06-07_informational_filing.pdf).

## Maximum Capacity Limit for 2011/12

In accordance with the methodology outlined in Market Rule 1, Section III.12.2.2 for the export-constrained Maine (ME) Load Zone, the ISO has calculated the MCL as 3,395 MW.

## Methodology

### Reliability Planning Model for ICR

The ICR was established using the Westinghouse Capacity Model Program (Capacity Model) developed by Westinghouse Electric Corporation/ABB. The Capacity Model is a computer program that uses probabilistic mathematics to simulate the random behavior of both loads and resources within a power system. The Capacity Model calculates the expected days per year that the bulk electric system would not have adequate resources to meet or exceed those daily peak loads. Inputs to the Capacity Model are various assumptions regarding peak load and capacity resources. The Capacity Model is 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. On a weekly basis, the program compares the available capacity resources with the load forecast to determine the weekly Loss of Load Probability (“LOLP”). Summation of the weekly LOLP over the Capability Year<sup>13</sup> gives the annual system Loss of Load Expectation (“LOLE”).

The calculation process begins with the determination of the system LOLE using both existing and known resource additions to meet projected loads. 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) with both existing and known resource additions, additional resources are not required. However, if the system is less reliable than the resource adequacy criterion (i.e., the system LOLE is greater than 0.1 days per year), additional resources called proxy units are subsequently added to the model to meet the resource adequacy criterion.

In order to calculate the ICR, the system being modeled must meet the resource adequacy criterion. Under the condition where New England is forecast to be less reliable than the resource adequacy criterion, proxy resources are used within the model to meet the additional capacity needs.

Included as variables in the Westinghouse Capacity Model are:

- a) *The possibility that load forecasts may be exceeded due to weather variations.*
- b) *Immature and mature equivalent forced outage rates appropriate for generating units of various sizes and types, recognizing partial and full outages.*
- c) *Due allowance for scheduled outages and deratings.*
- d) *Seasonal adjustment of resource capability.*
- e) *Generator maintenance requirements.*
- f) *Available load relief from operating procedures.*
- g) *The reliability benefits of interconnections with neighboring systems.*

---

<sup>13</sup> Capability Year starts on June 1 of year one and ends on May 31 of the following year.

*h) Other factors as may be appropriate.*

### **Reliability Planning Model for LSR and MCL**

The General Electric Multi-Area Reliability Simulation Model (GE MARS) was used to calculate LSR and MCL. GE MARS uses a sequential Monte Carlo simulation to compute the resource adequacy of a power system which is comprised of a number of interconnected areas containing load and generation. This Monte Carlo process repeatedly simulates the year (multiple replications) to evaluate the impacts of a wide-range of possible random combinations of generator outages. The transmission system is modeled in terms of transfer limits (constraints) on the interfaces between the interconnected areas. Chronological system histories are developed by combining randomly generated operating histories of the generating units and inter-area transfer limits serving the hourly chronological loads. For each hour, the program computes the isolated area margins based on the available capacity and demand in each area. GE MARS then uses a transportation algorithm to determine the extent to which areas with negative margins can be assisted by areas having positive (excess) margins, subject to the available transfer constraints between such areas. 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; otherwise, it moves on to the next study year.

### **Installed Capacity Requirement Calculation**

The formula for calculating the New England ICR is:

**Figure 1: Formula for ICR Calculation**

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

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 12 & 13 and the modeling of the minimum 200 MW Operating Reserve limit
ALCC	= Additional Load Carrying Capability (as determined from the Westinghouse Capacity Model)
HQICCs	= Monthly Hydro-Québec Interconnection Capability Credits

The New England ICR formula is designed such that the results identify the minimum amount of capacity required to meet ISO 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 identified. For the 2011/12 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 *Additional Load Carrying Capability* (ALCC). Therefore, no adjustments of additional capacity in the form of proxy units<sup>14</sup> were added to the model. When ALCC is used within the ICR calculation, the effect is to bring the entire New England Control Area to the annual resource adequacy criterion of 1 day in 10 years.

In the ICR calculation, the HQICCs are treated differently than other resources and are not adjusted by the ALCC amount. Table 2 shows the details of the ICR calculation for the Capability Year 2011/12.

**Table 2: ICR Calculation Details (MW)**

Total Capacity	2011/2012
Internal Installed Capacity	31,467
Tie Benefits	1,800
Imports/Sales	905
Demand Resources	2,401
OP 4 - Action 12 & 13 & Min OR	407
Expansion Unit Capacity	
Modeled Capacity	36,980

ICR Calculation Details	2011/2012
Annual Peak	29,405
Modeled Capacity	36,980
Tie Benefits	1,800
HQICCs	911
OP 4 - Action 12 & 13 & Min OR	407
ALCC	2,030
Installed Capacity Requirement	<b>33,439</b>

### Local Sourcing Requirements Calculation

For this year, Market Rule 1, Section III.12.2.1 was modified to adjust the LSR calculation to eliminate the excess MW leftover from the process of adding a proxy unit greater than what was needed within the Load Zone to meet the resource adequacy criterion. As a result of this market rule change, an additional adjustment to remove any surplus capacity resulting from the addition of a proxy unit was added to the formula for calculating LSR. The new formula for calculating LSR is shown in Figure 2.

<sup>14</sup> 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.

For each import-constrained transmission Load Zone, the LSR 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 Control Area (ISO-NE CA) using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them including external Control Area support from tie benefits.
- b) Model the transmission interface constraint between the Load Zone under study and the rest of the ISO-NE CA.
- c) Add proxy units, if required, in the ISO-NE CA to meet the resource adequacy planning criterion of once in 10 years 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.
- d) Adjust the firm load within the Load Zone under study until the LOLE of the ISO-NE CA 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 CA.

LSR is then calculated using the formula:

### Figure 2: Formula for LSR Calculation

$$LSR_z = Resources_z + ProxyUnits_z - \left( \frac{ProxyUnits\ Adjustment_z}{1-FOR_z} \right) - \left( \frac{Firm\ Load\ Adjustment_z}{1-FOR_z} \right)$$

Where	$LSR_z$ $Resources_z$  $Proxy\ Units_z$ $Proxy\ Units\ Adjustment_z$  $Firm\ Load\ Adjustment_z$  $FOR_z$	= Local Sourcing Requirement for Load Zone 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. = MW of proxy unit additions in Load Zone Z. = MW of firm load added to (or unforced capacity subtracted from) Load Zone Z until the system LOLE equals 0.1 days/year. = MW of firm load added (or subtracted) within Load Zone Z to make the LOLE of the New England Control Area equal to 0.105 days per year. = 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.
-------	---	--

Table 3 shows the details of the LSR calculation for the Capability Year 2011/12.

**Table 3: LSR Calculation Details (MW)**

Zone		Connecticut	NEMA/BOSTON	RestofNewEngland (All Zones Except Maine)
Resource <sub>z</sub> * (inc. HQICCs)	[1]	8,189	3,753	32,096
Proxy Units <sub>z</sub>	[2]	0	0	0
Proxy Units Adjustment <sub>z</sub>	[3]	0	0	0
Firm Load Adjustment <sub>z</sub>	[4]	1,285	1,570	1,935
FOR <sub>z</sub>	[5]	0.0637	0.0964	0.0568
LSR <sub>z</sub>	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))]	6,817	2,016	30,044

### Maximum Capacity Limit Calculation

For each 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 CA using the GE MARS simulation model, reflecting load and resources (supply & demand-side) electrically connected to them, including external Control Area support from tie benefits.
- b) Model the transmission interface constraint between the Load Zone under study and the rest of the ISO-NE CA.
- c) Add proxy units, if required, in the ISO-NE CA 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.
- d) Adjust the firm load within the rest of the ISO-NE CA until the LOLE of the ISO-NE CA reaches 0.105 days per year LOLE. As firm load is added to (or subtracted from) the rest of ISO-NE CA, an equal amount of firm load is removed from (or added to) the Load Zone under study.

MCL is then calculated using the formula:

### Figure 3: Formula for MCL Calculation

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

Where

- MCL<sub>Y</sub> = Maximum Capacity Limit for Load Zone Y.
- ICR = MW of ICR.
- LSR<sub>Rest of New England</sub> = MW of Local Sourcing Requirement for the Rest of New England Control 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 4 shows the details of the MCL calculation for the Capability Year 2011/12.

**Table 4: MCL Calculation Details (MW)**

Zone		Maine
ICR for New England	[1]	33,439
LSR <sub>RestofNewEngland</sub>	[2]	30,044
Maximum Capacity Limit <sub>y</sub>	[3]=[1]-[2]	3,395

## Assumptions

Table 5 summarizes all of the input assumptions used for the calculation of the ICR Values, while Table 6 summarizes the numerical values of these assumptions sets. The assumptions are described in more detail following Tables 5 and 6.

**Table 5: Summary of Input Assumptions**

Load Forecast
Existing Capacity
<i>Generating Resources</i>
<i>Intermittent Power Resources</i>
<i>Demand Resources</i>
<i>Import Resources</i>
<i>Sales</i>
<i>New Capacity Resources</i>
<i>De-listed Capacity Resources</i>
Transmission Transfer Capability
<i>External Transmission Transfer Capability</i>
<i>Internal Transmission Transfer Capability</i>
Tie Benefits
<i>Individual Control Area Tie Benefits</i>
<i>HQICCs</i>
OP4 Load Relief
Operating Reserve
Resource Availability
<i>Generating Resource Forced Outages</i>
<i>Generating Resource Scheduled Outages</i>
<i>Demand Resources Availability</i>
Proxy Units

**Table 6: Value of Input Assumptions (MW)**

Type of Resource	Summer	Winter
Generating Resources	30,427.010	30,427.010
Intermittent Power Resources	1,039.644	1,217.054
Demand Resources	2,383.681	2,383.681
Adjustment for Demand Resources > 100% Performance	17.320	17.320
Import Resources	1,035.100	1,035.100
Export Delist	(100.000)	(100.000)
OP 4 Voltage Reduction	607.000	492.000
Minimum Operating Reserve	(200.000)	(200.000)
Tie Benefits (includes 911 MW of HQICCs)	1,800.000	1,800.000
<b>Total MW Modeled in ICR</b>	<b>37,009.755</b>	<b>37,072.165</b>

### **Load Forecast**

The New England and subarea load forecasts used in the calculation of ICR, LSR and MCL for 2011/12 are from the April 2008 *Forecast Report of Capacity, Energy, Loads and Transmission (CELT)*.<sup>15</sup> The peak load forecasts were developed by the ISO using economic and demographic assumptions and were reviewed by the NEPOOL Load Forecast Committee (LFC).<sup>16</sup>

### **Load Forecast as Modeled in the Westinghouse Capacity Model**

The relationship of system peak load to weather is represented by a probability distribution of New England's non-holiday weekday peak loads for each week of the year. These weekly distributions are represented in the Capacity Model with three parameters: the expected value (mean), the standard deviation, and the skewness<sup>17</sup> from the peak load forecast model. While the mean represents the most likely value of the weekly distributions, the standard deviation represents how widely spread the values in the distribution are and the skewness is a measure of the asymmetry of that distribution.

When applied to the load forecast, these three moments of the distribution are used to model the most likely peak forecast (mean), the effect of weather uncertainty (standard deviation), and the frequency of high loads not present in a normal distribution

<sup>15</sup> Located on ISO-NE's website at: <http://www.iso-ne.com/trans/celest/report/index.html>

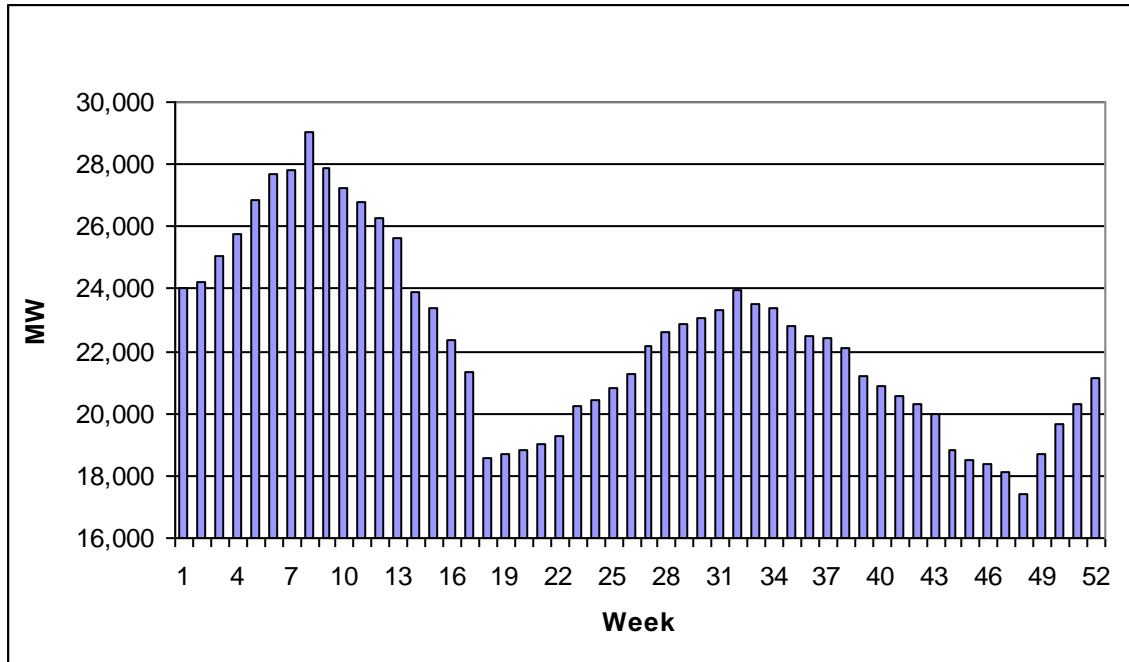
<sup>16</sup> The load forecast details, including assumptions and methodology for 2011/12 and other years covered by this study can be found at: [http://www.iso-ne.com/trans/celest/fsct\\_detail/index.html](http://www.iso-ne.com/trans/celest/fsct_detail/index.html).

<sup>17</sup> Skewness is represented in the model by the Third Cumulant which is Skewness\*Standard Deviation<sup>3</sup>.

(skewness). Monthly and seasonal peak loads are simply points on these distribution curves. For example, both the 50/50 and the 90/10 summer peak load forecast values are points on the same curve.

The chart below in Figure 4 shows the graphical representation of the weekly forecast distribution from which the summer 2011 peak load distribution shown in Table 7 is derived.

**Figure 4: 95th Percentile of the Weekly Peak Load Forecast Distribution<sup>18</sup>**



The summer 2011 forecast distribution of peak load is shown in Table 7. 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 the median value. The median is reported to facilitate comparisons, but the inherently uncertain nature of the load forecast is modeled by the forecast distributions used as inputs of the Westinghouse Capacity Model.

**Table 7: Summer 2011 Peak Load Forecast Distribution (MW)**

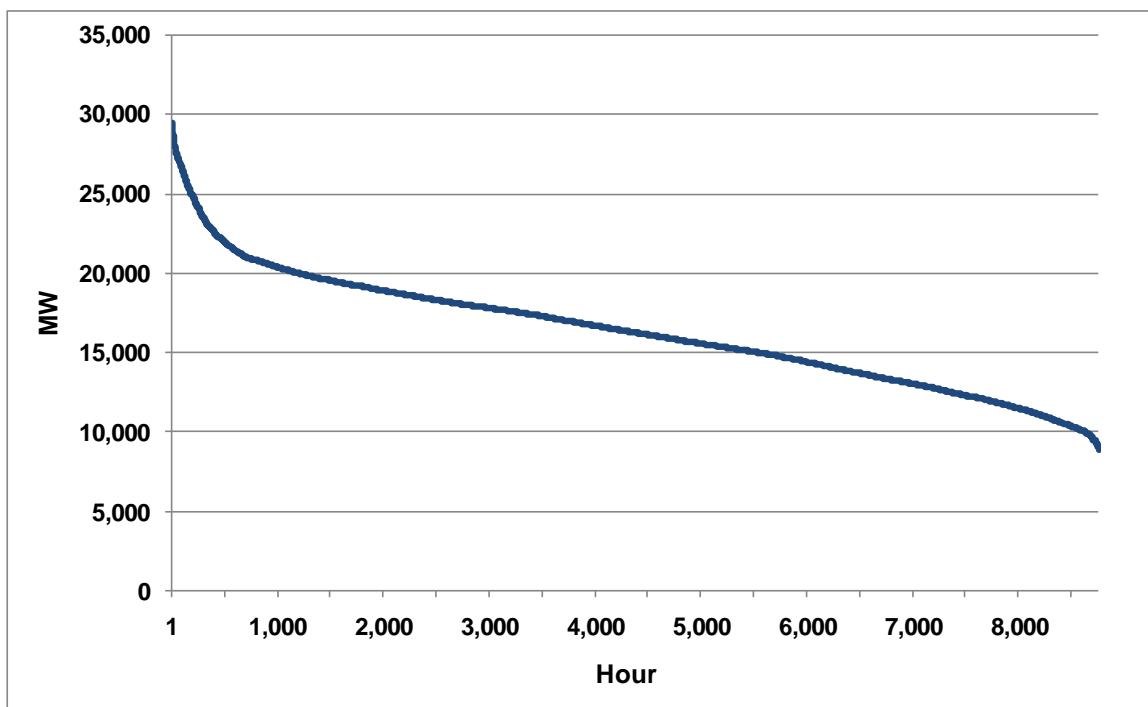
10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
28,000	28,285	28,550	28,985	29,405	29,810	30,165	30,740	31,525	32,125

<sup>18</sup> Week 1 is the first week of June 2010.

## Load Forecast as Modeled in the GE MARS Model

GE MARS models load using hourly chronological subarea loads. GE MARS can include the effects of load forecast uncertainty by calculating the Loss of Load Expectation (LOLE) for up to ten different load levels and computing a weighted-average value based on the input probabilities. Load forecast uncertainty multipliers are used to account for load uncertainty. These are the per unit multipliers used for computing the loads for which 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. The multipliers are allowed to vary by month.

**Figure 5: Forecasted New England Hourly Load Duration Curve for 2011/12**



## ***Existing Capacity***

Market Rule 1, Section III.12.7.2 details what shall be modeled in 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) Import Capacity Resources cleared in previous Forward Capacity Auctions and obligated for the relevant Capacity Commitment Period, 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 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.

Summaries of resources categorized as Existing Capacity in the ICR, LSR and MCL calculations are provided in the sections below<sup>19</sup>. It should be noted that while both summer and winter capacity values are shown, with the exception of Intermittent Power Resources (IPR), only summer capacity values are used in 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 in the ICR, LSR and MCL calculations were based on Qualified Existing Generating Resources for 2011/12 and are summarized in Table 8.

---

<sup>19</sup> For detailed data of Qualified Existing Resources used in the calculation of ICR, LSR and MCL see [http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000\\_09-09-08\\_fca\\_info\\_filing.pdf](http://www.iso-ne.com/regulatory/ferc/filings/2008/sep/er08-1513-000_09-09-08_fca_info_filing.pdf).

**Table 8: Existing Qualified Generating Capacity by Load Zone (MW)**

<b>Load Zone</b>	<b>Summer</b>
MAINE	2,995.753
NEW HAMPSHIRE	3,994.957
VERMONT	918.882
CONNECTICUT	7,022.167
RHODE ISLAND	2,323.893
SOUTH EAST MASSACHUSETTS	6,052.625
WEST CENTRAL MASSACHUSETTS	3,867.045
NORTH EAST MASSACHUSETTS & BOSTON	3,251.688
<b>Total New England</b>	<b>30,427.010</b>

### **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.

For the 2011/12 FCA, summer Qualified Capacity as modeled in the ICR calculation, will be calculated as the median of the net output during the Summer Reliability Hours, of the most recent five summer periods. The Summer Intermittent Reliability Hours, as defined in Section III.13.1.2.2.2.1(c) of the Market Rule, are the hours ending 1400 through 1800 in June through September. After June 1, 2010, Summer Reliability Hours will also include hours in which the ISO has declared a system-wide Shortage Event (if a Resource was located in an import-constrained Capacity Zone, Summer Reliability Hours will also include all Shortage Events within that Capacity Zone).

For the 2011/12 FCA, winter Qualified Capacity of an Intermittent Power Resource is the resource's net output in the Winter Intermittent Reliability Hours, as defined in Section III.13.1.2.2.2.2(c) of the Market Rule are the hours ending 1800 and 1900 in (October through May). After June 1, 2010, Winter Reliability Hours will also include hours in which the ISO has declared a system-wide Shortage Event and if the Intermittent Power Resource or Intermittent Settlement Only Resource was located in an import-constrained Capacity Zone, Winter Reliability Hours will also include all Shortage Events in that Capacity Zone.

Summer and winter capacities (by Load Zone) of existing IPR used within the ICR, LSR and MCL calculations were those which have Qualified as Existing Generating Resources, are shown in Table 9.

**Table 9: Existing IPR Resources by Load Zone (MW)**

<b>Load Zone</b>	<b>Summer</b>	<b>Winter</b>
MAINE	248.137	297.464
NEW HAMPSHIRE	119.698	146.124
VERMONT	66.403	113.522
CONNECTICUT	416.052	434.971
RHODE ISLAND	4.855	8.763
SOUTH EAST MASSACHUSETTS	80.523	86.151
WEST CENTRAL MASSACHUSETTS	36.591	59.308
NORTH EAST MASSACHUSETTS & BOSTON	67.385	70.751
<b>Total New England</b>	<b>1,039.644</b>	<b>1,217.054</b>

### **Demand Resources**

To participate in the Forward Capacity Auction as a Demand Resource, a resource must meet the definitions and requirements of Market Rule 1, Section III.13.1.4.1, which states that Existing Demand Resources shall include and are limited to (i) Demand Resources that have been in service and registered with the ISO to fulfill a Capacity Supply Obligation created by clearing in a past Forward Capacity Auction, (ii) Other Demand Resources in service and registered with the ISO during the ICAP Transition Period and before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction, or (iii) Demand Resources participating in the Real-Time Demand Response Program (30-Minute and 2-Hour) and in the Real-Time Profiled Response Program, as defined in Appendix E of Market Rule 1, before the Existing Capacity Qualification Deadline of the applicable Forward Capacity Auction.

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 in the calculation of the ICR Values shall be the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value.

The summer Qualified Capacity of a Demand Resource will be rated on the summer seasonal Demand Reduction Value calculation which is dependent upon the Demand Resource type, and includes resources in the On-Peak, Seasonal Peak, Critical Peak, Real-Time Demand Response and Real-Time Emergency Generation categories.

- On-peak Demand Resources are non-dispatchable measures that are not weather sensitive and will reduce their load during the Summer On-Peak hours of 1 p.m. to 5 p.m. for non-holiday weekdays during June, July and August and the Winter On-Peak Hours of 5 p.m. to 7 p.m. for non-holiday weekdays in December and January.

- Seasonal Peak Demand Resources are non-dispatchable, weather-sensitive measures that must reduce load during non-holiday weekdays when the Real-Time hourly system load is equal to or greater than 90% of the most recent “50/50” System Peak Load Forecast for the applicable summer or winter season.
- Critical Peak Demand Resources are measures that can be dispatched by the project owners and must reduce load across Forecasted Peak Hours when the ISO’s Hourly Day-Ahead Forecasted Load (for non-holiday weekdays) is equal to or greater than 95% of the most recent 50/50 System Peak Load Forecast for the applicable summer or winter season, and Shortage Hours when the ISO implements OP-4 Action 6 or higher.
- Real-Time Demand Response Resources are dispatchable resources with no binding air quality permitting restrictions during Critical peak hours. They must curtail electrical usage within 30 minutes of receiving a Dispatch Instruction from the ISO and continue curtailing usage until receiving a Dispatch Instruction to restore electrical usage.
- Real-Time Emergency Generation Resources (RTEG) are distributed generation whose Federal, State and/or Local air quality permit(s) limit the operation of these generators to OP-4, Action 12 – the action which implements voltage reductions of five percent (5%) of normal operating voltage that require more than 10 minutes to implement. These resources must curtail electrical usage within 30 minutes of receiving a Dispatch Instruction from the ISO and continue curtailing usage until receiving a Dispatch Instruction to restore electrical usage. The amount of Emergency Generators used to meet the ICR is limited to 600 MW.

Existing Demand Resources, by Load Zone, used within the ICR, LSR and MCL calculations are those which have Qualified as an Existing Demand Resource Capacity for the 2011/12 FCA, are shown in Table 10.

**Table 10: Existing Demand Resources by Load Zone (MW)**

Load Zone	On-Peak	Seasonal Peak	Critical Peak	RT Demand Response	RT Emergency Gen	Total
MAINE	22.81	-	105.29	163.55	35.02	326.67
NEW HAMPSHIRE	38.34	-	1.35	26.12	39.14	104.95
VERMONT	50.47	-	-	20.66	18.12	89.25
CONNECTICUT	74.52	120.45	14.47	240.42	300.20	750.06
RHODE ISLAND	39.89	-	5.35	36.72	93.08	175.03
SOUTH EAST MASSACHUSETTS	76.43	-	2.08	60.65	77.24	216.40
WEST CENTRAL MASSACHUSETTS	67.47	10.23	18.02	98.03	101.04	294.80
NORTH EAST MASSACHUSETTS & BOSTON	116.26	-	49.92	117.17	143.16	426.51
<b>Total New England</b>	<b>486.20</b>	<b>130.69</b>	<b>196.49</b>	<b>763.31</b>	<b>807.00</b>	<b>2,383.68</b>

## Import Resources

For the purposes of the FCA for 2011/12, Market Rule 1, Section III.13.1.3.3 dealing with the Qualification Process for Existing Import Capacity Resources states that to be Qualified as an Existing Capacity Import the import must have: (i) *documentation of a multi-year contract entered into before the Existing Capacity Qualification Deadline to provide capacity in the New England Control Area from outside the New England Control Area for a period including the whole Capacity Commitment Period, including documentation of the MW value of the contract; or (ii) proof of ownership or direct control over one or more External Resources that will be used to back the Existing Import Capacity Resource during the Capacity Commitment Period, together with information to establish the summer and winter ratings of the resource(s) backing the import.* In either case, the Market Participant must specify the interface over which the capacity will be imported.

The Summer Qualified Capacity of an Existing Import Capacity Resource modeled within the ICR calculation and is based on the data provided to the ISO by the Existing Capacity Qualification deadline is subject to ISO review and verification.

The rating of imports used in the calculation of the ICR Values is the summer Qualified Capacity value reduced by any reserve margin adjustment factor that is otherwise included in the summer Qualified Capacity value.

Existing Import Resources used within the ICR, LSR and MCL calculations were based on Qualified Existing Resources for 2011/12, are shown in Table 11.

**Table 11: Existing Import Resources (MW)<sup>20</sup>**

Import Resource	Transmission Interface	MW
NYPA - CMR	NY AC Ties	68.800
NYPA - VT	NY AC Ties	15.300
VJO - Highgate	Highgate	225.000
VJO - Phase I/II	Phase II	110.000
Erie Boulevard Hydropower - Import	NY AC Ties	641.000
<b>Total</b>		<b>1060.100</b>

For the 2011/12 ICR modeling assumptions, a 25 MW derate was applied to the VJO – Highgate import to reflect a 200 MW planning assumption limitation on the transfer capability of the Highgate interface. A 30 MW derate was modeled for the VJO import over the Phase II facilities to reflect the 30 MW transfer capability of the Derby Line, which is used to serve the existing Block Load which qualified as an Existing Capacity Resource at 60 MW.

<sup>20</sup> Table 11 does not reflect the 25 MW and 30 MW VJO deratings used in the models.

## ***Sales***

An Export Bid is a bid that may be submitted by certain resources in the FCA to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1. One sale of export 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.

## ***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. In addition, paragraph (b) requires all resources cleared in previous Forward Capacity Auctions or obligated for the relevant Capacity Commitment Period to also be included. Resource capacity that qualifies as a New Capacity Resource is not modeled within the ICR calculation for 2011/12.

## ***De-Listed Capacity Resources***

Market Rule 1, Section III.12.7.2 also identifies the Capacity that shall be excluded from the ICR and LSR calculations as:

- (b) Resources for which Permanent De-list Bids cleared in previous Forward Capacity Auctions.

For the 2011/12 FCA, any resource with a cleared Permanent De-list bid in the 2010/11 FCA was not included in the ICR calculation.

## ***Transmission Transfer Capability***

Market Rule 1, Section III.12.5 requires that the ISO update the transmission interface limits for each internal and external interface for the Capability Year 2011/12. While the external transmission limits are not used within ICR calculation, they are used in the determination of tie benefits, including HQICCs, and will also be used in the FCA to limit purchase of external Installed Capacity. In addition, internal transmission limits are used in the determination of the LSR and MCL.

## ***External Transmission Transfer Capability***

Table 12 shows the External Transmission Transfer Capabilities that were assumptions within the tie benefits study and as will be used by the ISO within the 2011/12 FCA.

**Table 12: External Transmission Transfer Capability Limits (MW)**

Interface	Summer Limit	Winter Limit
Hydro-Québec to New England (Highgate)	200	200
Hydro-Québec to New England (Phase II)	1,400	1,400
New Brunswick to New England	1,000	1,000
New York to New England (AC Interface)	1,525	1,600
New York to New England (Cross Sound Cable DC Interface)	330	330

### Internal Transmission Transfer Capability

For the 2011/12 FCA, the ISO has evaluated three Load Zones relating to their LSR 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 13 shows the Internal Transmission Transfer Capability Limits for the CT and NEMA/Boston Load Zones as used in the calculation of LSR and the ME Load Zone as used in the calculation of MCL.

**Table 13: Internal Transmission Transfer Capability Limits (MW)**

Interface	Limit
CT Import	2,500
NEMA/Boston Import	4,900
ME/NH	1,575

### Tie Benefits

New England’s Commission-approved method for establishing the ICR requires that assumptions be made regarding the tie benefits value to be used as an input in the formula. Tie benefits from neighboring control areas reduce the ICR and the need to buy capacity to meet the New England resource adequacy criterion. The tie benefits from neighboring Control Areas reflect the amount of emergency assistance that New England could rely on, without jeopardizing reliability in New England or its neighboring control areas, in the event of a capacity shortage in New England.

The ICR for the 2011/12 Capability Year reflects total tie benefits calculated in accordance with a new methodology proposed in revisions to the ISO Tariff, submitted in the July 31st Filing to comply with the Commission’s directives in its 2010/2011 ICR Order. The new methodology is pending before the Commission in Docket ER08-41-002, and the ISO and NEPOOL’s July 31, 2008 joint filing in that proceeding explains the methodology and demonstrates the justness and reasonableness of that methodology.

Several comments and a protest challenging that methodology have been filed and are also pending.

Under the proposed modifications, HQICC values are established using the results of a probabilistic calculation of tie benefits rather than using a deterministic calculation methodology. The ISO continues using the existing methodology for calculating total tie benefits from the Québec, Maritimes and New York Control Areas using a probabilistic multi-area reliability model. In addition, as explained further below, these neighboring Control Areas will continue to be modeled using “At Criteria” modeling assumptions. However, under the approach proposed in the July 31st Filing, implemented herein, tie benefits from individual Control Areas are determined based on the results of individual probabilistic calculations performed for each of the three neighboring Control Areas, obviating the need for a deterministic calculation of HQICCs that arbitrarily reduces the tie benefit values from the Maritimes and New York Control Areas.

Under the proposed allocation methodology, tie benefits from each Control Area are calculated using the same GE MARS program with “At Criteria” modeling assumptions.<sup>21</sup> Using the “At Criteria” modeling assumption is consistent with applicable Commission-approved tariff provisions (namely, section III.12.9 of Market Rule 1) and with Commission precedent.<sup>22</sup>

In other words, the allocation methodology for calculating Individually-Calculated Capacity Equivalents for Maritimes and New York is applied for determining the tie benefits from Québec as well. If the sum of the Individually-Calculated Capacity Equivalents from each of the three neighboring Control Areas does not equal the total tie benefits calculated using the multi-area reliability model, tie benefits from each Control Area are adjusted in a pro rata manner based on a ratio of the tie benefits from each individual Control Area to the sum of the tie benefits from all Control Areas. Thus, the proposed approach does away with the use of the deterministic method for calculating HQICCs and employs the same method for calculating tie benefits from all three directly connected Control Areas.

---

<sup>21</sup> From Market Rule 1, Section III.12.9: The ISO shall calculate tie benefits using “at-criteria” assumptions for purposes of modeling the adjacent Control Areas, except that when calculating the Installed Capacity Requirement, the Local Sourcing Requirements and Maximum Capacity Limits for use in the annual reconfiguration auction closest to the relevant Capacity Commitment Period, the ISO shall calculate tie benefits using “as-is” data for the purposes of modeling the adjacent Control Areas.

<sup>22</sup> In the 2010/2011 ICR Order, the Commission determined:

The Filing Parties’ “at criteria” assumption reflecting a Loss of Load Expectation included in the instant filing is just and reasonable because it models potential transmission constraints on neighboring control areas. The Filing Parties’ approach recognizes that the exact system conditions of neighboring control areas are unknown three years in advance and therefore builds a conservative margin of safety into its calculation of tie benefits available. We find this to be a reasonable approach.

2010/2011 ICR Order at P 73.

## **Total Tie Benefits**

Tie benefits from neighboring Control Areas are used as an input assumption in the calculations of ICR, and LSR for the 2011/12 Capability Year. Market Rule 1, Section III.12.9 requires that total tie benefits be calculated using the results of a probabilistic calculation that determines the LOLE of the New England system on an isolated basis (that is, excluding connections with other directly connected Control Areas) and an interconnected basis (that is, including all existing connections with directly connected Control Areas). The difference in the two calculations is then translated into a capacity-equivalent MW value to determine the overall capacity benefit of the interconnection. This is the existing methodology and no changes were proposed within the FERC Filing referencing tie benefits to the calculation methodology for the determination of the total tie benefits.

For Control Areas directly connected to New England, the load and resource assumptions are modeled such that the area is “At-Criterion.” This means the Control Area under study only has available those resources required to exactly meet the Northeast Power Coordinating Council (NPCC) Resource Adequacy Planning Criterion, as measured by having an LOLE of 0.1 days/year. The directly-connected Control Areas are modeled in this manner because the actual amount of resources that may be available in the future study year is unknown. Nonetheless, by adhering to such reliability standards, these Control Areas can reasonably be expected to have enough resources available to meet the LOLE criterion and, therefore, can be planned in a manner consistent with this requirement. Using this methodology, the ISO has determined that total tie benefits for the 2011/12 Capability Year are 1,800 MW.

## **Individual Control Area Tie Benefits**

Proposed changes to Market Rule 1, Section III.12.9.1 document the new methodology for determining individual Control Area tie benefits. *These shall be determined based on the LOLE calculated before and after removing the direct interconnections between New England and the target external Control Area used to calculate the total amount of tie benefits. The tie benefits from the target Control Area, if any, shall be the amount of firm capacity equivalents needed in the New England Control Area to bring the New England Control Area LOLE, without the New England interconnections with the target Control Area included in the interconnected system, equal to the New England Control Area LOLE with the interconnections with the target Control Area included in the interconnected system.*

Specifically, for the 2011/12 Capability Year, the individual tie benefits were developed by first determining the value of the firm capacity equivalents of 160 MW for New York (NY), 660 MW for the Maritimes (MT) and 840 MW for Québec (Q). The sum of these individual tie benefits is 1,660 MW; therefore an adjustment calculation is made to bring these values up to their individual contributions to the 1,800 MW of total tie benefits determined with the methodology described above. This ratio calculation is shown for each of the individual Control Areas below:

- Adjusted Québec Tie Benefit Contribution:  

$$TB_{Tie\_Q} = 1,800 * 840 / ( 840 + 660 + 160 ) = 911 \text{ MW}$$
- Adjusted Maritimes Tie Benefit Contribution:  

$$TB_{Tie\_MT} = 1,800 * 660 / ( 840 + 660 + 160 ) = 716 \text{ MW}$$
- Adjusted New York Tie Benefit Contribution:  

$$TB_{Tie\_NY} = 1,800 * 160 / ( 840 + 660 + 160 ) = 173 \text{ MW}$$

Therefore, the final individual tie benefits for the 2011/12 Capability Year are 911 MW from Québec, 716 MW from New Brunswick and 173 MW from New York, as determined by the ratio calculation based on the probabilistic simulations.

### **Hydro-Québec Interconnection Capability Credits<sup>23</sup>**

In the proposed changes to Market Rule 1, Section III.12.9.2, the ISO states that the MW value of the tie benefits over the Hydro-Québec (HQ) Interconnection and the associated HQICCs will be the results of the probabilistic tie benefits methodology as described in the section above. Using this methodology, the ISO has determined that HQICCs will be 911 MW for all the months of the 2011/12 Capability Year. At its August 1, 2008 meeting, the PC voted to support these values, with one opposition and 13 abstentions noted.

### ***OP 4 Load Relief***

Market Rule 1, Section III.12.7.4 requires that load and capacity relief available from Operating Procedure No. 4 - Action During a Capacity Deficiency (OP 4) should be modeled within the ICR and LSR calculations. OP 4 - Action 12 provides for implementation of a 5% voltage reduction requiring more than 10 minutes to respond, while OP 4 - Action 13 provides for a 5% voltage reduction achievable in 10 minutes or less. Load relief assumptions are based on actual results from seasonal system-wide voltage reduction tests which are documented in Appendix A of OP 4<sup>24</sup>.

During the stakeholder process for determining the amount of OP 4 Voltage Reduction to be modeled within the ICR calculation for the 2011/12 Capability Year, it was decided to average the results of the latest available spring and fall system-wide voltage reduction tests. These test results are shown in Table 14 below.

---

<sup>23</sup> The 2011/12 Capability Year HQICCs values were filed with the FERC in the 2011/12 ICR filing ER08-1531-000..

<sup>24</sup> OP 4 Appendix A is available at:

[http://www.iso-ne.com/rules\\_proceeds/operating/isone/op4/op4a\\_rto\\_final.pdf](http://www.iso-ne.com/rules_proceeds/operating/isone/op4/op4a_rto_final.pdf)

**Table 14: Spring and Fall 2007 OP 4 Voltage Reduction Test Results (%)**

Test Date	Action 12 >10 Min	Action 13 ≤ 10 Min	Total OP 4 Voltage Reduction
Spring 2007	0.90%	1.28%	2.18%
Fall 2007	1.00%	0.95%	1.95%
<b>Average of Spring and Fall Tests</b>	0.95%	1.12%	2.07%

Table 14 documents the most recent voltage reduction test results which show an average of 0.95 % of total system load was curtailed within the greater than 10-minute period utilized in Action 12, while an average of 1.12% of total system load was curtailed for the 10-minute or less category of Action 13. The percentage values in Table 14 are converted into percent of a peak load MW equivalent and used as multipliers on the summer and winter peak load to obtain the OP 4 load relief assumptions for the ICR and LSR for the 2011/12 Capability Year.

Table 15 shows the MW amount of voltage reduction modeled as OP 4 load relief of Actions 12 & 13 for each of the months of the 2011/12 Capability Year within the ICR calculations.

**Table 15: OP 4 Action 12 & 13 Modeled (MW)**

Month	Peak Load	Action 12 5% Voltage Reduction > 10min	Action 13 5% Voltage Reduction < =10min	Total 5% Voltage Reduction from OP4
June – September	29,405	279	328	607
October – May	23,830	226	266	492

### ***Operating Reserve***

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

### ***Availability***

#### **Generating Resource Forced Outages**

A 5-year, historical average of unit-specific forced outage assumptions is determined for each generating unit qualified as an Existing Generating Capacity Resource using its

individual unit data of monthly Equivalent Forced Outage Rate - Demand (EFORd)<sup>25</sup> values from NERC's Generating Availability Data System (GADS). NERC GADS data submitted by generators to ISO-NE for the months of March 2003 through February 2008 is used to create an EFORd value for each unit that submits such data. NERC Class Average data is used as a substitute for immature units and units that are not required to submit GADS data.

Table 16 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 Capacity Model and GE MARS, the calculated EFORd for each generating resource is used as an input.

The capacity-weighted EFORd is not associated with the weighted Seasonal EFORd, which will be calculated for each generating resource and weights unavailability higher during Seasonal Peak Hours and Shortage Hours. This weighted EFORd will be phased in according to the schedule defined in Market Rule 1, Section III.8.8.1.2.

### **Generating Resource Scheduled Outages**

A weekly representation of a generator's scheduled outages is another input into the Capacity Model. Included in the scheduled outages are annual maintenance outages and unit outages scheduled more than 14 days in advance. A single value is calculated for each unit, based on a 5-year historical average. In addition to the EFORd data, Table 16 illustrates the average maintenance weeks assumed for each type of unit category, weighted by the summer capability. NERC Class Average data was used to calculate the average maintenance weeks for new capacity additions and immature units.

---

<sup>25</sup> The calculation methodology of EFORd can be found in ISO-NE Manual 20 at [http://www.iso-ne.com/rules\\_proceeds/isone\\_mnls/M20/index.html](http://www.iso-ne.com/rules_proceeds/isone_mnls/M20/index.html).

**Table 16: Generating Resource EFORD and Maintenance Weeks by Category**

<b>Resource Category</b>	<b>Summer MW</b>	<b>Assumed Capacity Weighted EFORD</b>	<b>Assumed Maintenance Weeks</b>
Combined Cycle	11,021	5.17	5
Fossil	9,547	7.56	5
Nuclear	4,668	1.56	3
Hydro (Includes Pumped Storage)	3,015	1.65	3
Combustion Turbine	1,885	6.55	2
Diesel	223	6.51	1
Miscellaneous	68	5.18	0
<b>Total System</b>	<b>30,427</b>	<b>5.11</b>	<b>4</b>

### **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 5 years for the second FCA and subsequent auctions. Since this method takes into account the resources' historic availability into their ratings, these resources are assumed 100% available in the models.

### **Demand Resources Availability**

#### **Passive Demand Resources**

Demand Resources in the On-Peak and Seasonal Peak categories of Demand Resources are considered as 100% available in the models. These two categories consist of passive resources such as energy efficiency, which are considered always “*in service*” and as such, are assumed 100% available.

**Table 17: Passive Resource – Summer MW and Performance %**

Load Zone	On-Peak		Seasonal Peak	
	MW	%	MW	%
MAINE	22.81	100	-	-
NEW HAMPSHIRE	38.34	100	-	-
VERMONT	50.47	100	-	-
CONNECTICUT	74.52	100	120.45	100
RHODE ISLAND	39.89	100	-	-
SOUTH EAST MASSACHUSETTS	76.43	100	-	-
WEST CENTRAL MASSACHUSETTS	67.47	100	10.23	100
NORTH EAST MASSACHUSETTS & BOSTON	116.26	100	-	-
<b>Total New England</b>	<b>486.20</b>	<b>100</b>	<b>130.69</b>	<b>100</b>

**Demand Response Resources**

Performance of Demand Resources within the Real-Time Demand Response and Critical Peak categories are measured by actual response during all historical events, including audits and OP 4 events, for all years of the current Demand Response programs (2003-2007). To calculate the percent historical performance, the actual load curtailed or generation provided during each such event is divided by the enrolled MW of resources within the program at the time of the event.

These values were reviewed during the stakeholder process by the PSPC and changes to the process of calculating the historical averages were incorporated. These changes exclude resources that had reported a static baseline during the August 15, 2007 event audit, which caused them to have an over-reported response and also to factor in other pertinent exclusions.

Also discussed during the stakeholder review process was a proposal to cap the performance of resources at 100% for those resources that perform better than 100% of their registered MW value. It was decided not to cap these resources’ performance rates which then resulted in both Maine and Vermont Load Zones recording performance rates above 100% in certain resource categories. These are modeled within both the Capacity Model and GE MARS model as additional capacity (17.23 MW) above the Qualified Demand Resource capacity (excluding Reserve Margin gross-up).

Performance ratings of Demand Resources in future FCAs may include performance measured during Shortage Hours (OP 4 Action 6 and higher) and/or Forecast Peak Hours, depending on the type of Demand Response resource.

The results of this review and the performance rates modeled for each of the Load Zones is shown in Table 18.

**Table 18: Demand Response Resources Summer MW and Performance %**

Load Zone	Critical Peak		RT Demand	
	MW	%	MW	%
MAINE	105.29	106	163.55	106
NEW HAMPSHIRE	1.35	66	26.12	66
VERMONT	-	-	20.66	105
CONNECTICUT	14.47	69	240.42	69
RHODE ISLAND	5.35	69	36.72	69
SOUTH EAST MASSACHUSETTS	2.08	54	60.65	54
WEST CENTRAL MASSACHUSETTS	18.02	75	98.03	75
NORTH EAST MASSACHUSETTS & BOSTON	49.92	76	117.17	76
<b>Total New England</b>	<b>196.49</b>	<b>76</b>	<b>763.31</b>	<b>76</b>

**Emergency Generator Demand Resources**

Demand Resources in the Real-Time Emergency Generator category have an assumed availability rate of 79%. This assumption is based on the average of the 2003-2007 audit and OP 4 event responses for all Real-Time Emergency Generators enrolled as OP 4 - Action 12 Emergency Generating Resources. Table 19 shows the Summer MW value of the Real-Time Emergency Generators and their performance rating by Load Zone as used in the models.

**Table 19: Real-Time Emergency Generators - Summer MW and Performance %**

Load Zone	RT Emergency Gen	
	MW	%
MAINE	35.02	79
NEW HAMPSHIRE	39.14	79
VERMONT	18.12	79
CONNECTICUT	300.20	79
RHODE ISLAND	93.08	79
SOUTH EAST MASSACHUSETTS	77.24	79
WEST CENTRAL MASSACHUSETTS	101.04	79
NORTH EAST MASSACHUSETTS & BOSTON	143.16	79
<b>Total New England</b>	<b>807.00</b>	<b>79</b>

***Proxy Units***

Section III.12.7.1 of Market Rule 1 states that when the available resources are insufficient for the unconstrained New England Control Area to meet the resource adequacy planning criterion, proxy units<sup>26</sup> shall be used as additional capacity to determine ICR and the LSR. The proxy units shall reflect resource capacity and outage characteristics such that when the proxy units are used in place of all other resources in

<sup>26</sup> Proxy unit size and characteristics were based on a recommendation made by ISO-NE to the Installed Capacity Stakeholder Process Working Group (ICWG) at their April 13, 2006 meeting. For a copy of this presentation, please see: [http://www.iso-ne.com/committees/comm\\_wkgrps/otr/icsp/mtrls/2006/apr132006/expansion\\_units.pdf](http://www.iso-ne.com/committees/comm_wkgrps/otr/icsp/mtrls/2006/apr132006/expansion_units.pdf)

the New England Control Area, the reliability, or LOLE, of the New England Control Area does not change. The characteristics of the proxy unit are:

- Size = 350 MW
- EFORd = 5.54%
- Annual Maintenance Requirement = 5 weeks

When modeling transmission constraints for the determination of Local Sourcing Requirements, the same proxy units may be added to the import-constrained Load Zone or elsewhere in the rest of the New England Control Area, depending on where system capacity is needed to meet the resource adequacy criterion.

For the 2011/12 Capability Year ICR calculation, no proxy units were required within the analysis.

## **Difference from 2010/11 ICR Values**

### **Change in ICR**

In an effort to quantify the effects that each input assumption has on the determination of ICR, the ISO began with the input assumptions associated with the 2010/11 Capability Year ICR and incrementally substituted each assumption with the corresponding 2011/12 Capability Year assumption. The net of these changes in 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.

Note that the effect of Load Forecast also incorporates a change in the Load Forecast methodology, which produced a different style of weekly peak load distribution from the distributions associated with the 2007 CELT Load Forecast. Using the 2008 CELT Load Forecast for both the 2010/11 and 2011/12 Capability Years, would have resulted in an increase of 587 MW for the ICR for 2011/12 over the 2010/11 ICR. However, the load forecast distribution incorporates the old methodology for the 2010/11 calculation and the new methodology for the 2011/12 calculation, therefore the change in ICR due to the load forecast is 280 MW.

**Table 20: Summary of ICR Input Assumptions for 2011/12 and 2010/11**

Assumption	2010/2011 Capability Year		2011/2012 Capability Year		Effect on ICR
<b>Tie Benefits</b>	<b>MW</b>		<b>MW</b>		<b>MW</b>
HQICCs	1400		911		-451
Maritimes	360		716		
New York	100		173		
<b>Total</b>	<b>1860</b>		<b>1800</b>		
<b>Capacity</b>	<b>MW</b>	<b>Weighted Forced Outage</b>	<b>MW</b>	<b>Weighted Forced Outage</b>	<b>MW</b>
Demand Resources	748	14.79%	2,384	14.75%	88
Generation - Regular	30,148	5.33%	30,427	5.11%	-100
Generation - IPR	1,058	0%	1,040	0%	
Imports & Sales	291	-	905	-	-72
	<b>MW</b>		<b>MW</b>		<b>MW</b>
50/50 Load Forecast	29,035 (2007 CELT)		29,405 (2008 CELT)		280
OP4 5% VR	633		607		34
<b>Final ICR</b>	<b>33,705</b>		<b>33,439</b>		<b>266</b>

As shown in Table 20, the assumption with the greatest effect on ICR is the tie benefits assumption. This is primarily due to the change in value for the HQICCs from the deterministically calculated value of 1,400 MW to the probabilistically calculated value of 911 MW. Since the ICR formula adds the HQICCs back into the ICR value as an unadjusted amount, the net change in HQICCs of -489 MW from 2010/11 to 2011/12 accounts for the bulk of the difference between the ICR values for the two years.

When all resource assumptions are updated, including the load forecast, OP 4 and resource rating and availability assumptions, the ICR for the 2011/12 Capability Year is 266 MW or 0.8% lower than the ICR value for the 2010/11 Capability Year, driven primarily by the change in the methodology for calculating HQICCs.

### **Change in LSR**

Table 21 shows the difference in the assumptions and results of the 2011/12 LSR calculation, as compared to the 2010/11 LSR calculation for the CT load zone.

**Table 21: Summary of Differences in 2011/12 & 2010/11 LSR for CT (MW)**

Assumption	Formula Reference	2011/12	2010/11
Load (50/50)		7,750	7,697
resource <sub>z</sub> *	[1]	8,189	7,538
Proxy Units <sub>z</sub>	[2]	0	0
Proxy Units Adjustment <sub>z</sub>	[3]	0	0
Firm Load Adjustment <sub>z</sub>	[4]	1,285	490
FOR <sub>z</sub>	[5]	0.0637	0.0588
LSR <sub>z</sub>	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	6,817	7,017

Table 22 shows the difference in the assumptions and results of the 2011/12 LSR calculation, as compared to the 2010/11 LSR calculation for the NEMA/Boston load zone.

**Table 22: Summary of Differences in 2011/12 & 2010/11 LSR for NEMA/Boston (MW)**

Assumption	Formula Reference	2011/12	2010/11
Load (50/50)		5,815	5,767
resource <sub>z</sub> *	[1]	3,753	3,740
Proxy Units <sub>z</sub>	[2]	0	0
Proxy Units Adjustment <sub>z</sub>	[3]	0	0
Firm Load Adjustment <sub>z</sub>	[4]	1,570	1,375
FOR <sub>z</sub>	[5]	0.0964	0.0798
LSR <sub>z</sub>	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	2,016	2,246

### **Change in MCL**

Table 23 shows the difference in the assumptions and results of the 2011/12 LSR calculation, as compared to the 2010/11 LSR calculation for the Rest-of-New England area (used in the determination of MCL for the ME load zone).

**Table 23: Summary of Differences in 2011/12 & 2010/11 LSR for Rest-of-New England (MW) (Used in ME MCL Calculation)**

Assumption	Formula Reference	2011/12	2010/11
Load (50/50)		27,200	26,889
resource <sub>z</sub> *	[1]	32,096	30,260
Proxy Units <sub>z</sub>	[2]	0	350
Proxy Units Adjustment <sub>z</sub>	[3]	0	0
Firm Load Adjustment <sub>z</sub>	[4]	1,935	720
FOR <sub>z</sub>	[5]	0.0568	0.0531
LSR <sub>z</sub>	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	30,044	29,850

Table 24 shows the difference in the assumptions and results of the 2011/12 MCL calculation, as compared to the 2010/11 MCL calculation for the ME Load Zone

**Table 24: Summary of Differences in 2011/12 and 2010/11 MCL for ME**

Assumption	Formula Reference	2011/12	2010/11
Load (50/50)		2,205	2,146
ICR for New England	[1]	33,439	33,705
LSR <sub>RestofNewEngland</sub>	[2]	30,044	29,850
Maximum Capacity Limit <sub>γ</sub>	[3]=[1]-[2]	3,395	3,855

## Conclusions

The publication of this report documents New England's ICR, LSR and MCL (collectively the "ICR Values") for the 2011/12 Capability Year corresponding to the second Forward Capacity Auction. While these ICR Values failed to receive majority support at both the RC and PC Committee levels of the NEPOOL governance structure, the underlying assumptions and methodology nonetheless received extensive review at the technical committee level of the PSpC and is the result of stakeholder input and compromise. Therefore, the ISO believes that with the near majority support and the intensive stakeholder review and input, these ICR Values accurately reflect the capacity requirements for the 2011/12 Capability Year based on the available assumptions and has subsequently filed these values with the FERC. Under the FCM, the ICR will be used by the ISO as the basis to purchase sufficient capacity to meet the resource adequacy criterion during the 2011/12 Capability Year.

The FCM for the second Capability Year will commence on June 1, 2011, and the FCM auction to purchase the ICR for that year is scheduled for December 8, 2008. Based on the amount of capacity that cleared the first FCA for the 2010/11 Capability Year and with new resource development through the FCM and the number of generators in the ISO Generator Interconnection Queue, New England most likely will meet its long-term resource adequacy requirements through established planning and market mechanisms.

For the 2011/12 Capability Year, a record number of Demand Resources have been qualified as resources to participate in the second FCA. This has created both operational and modeling challenges for the ISO and stakeholders. New England is leading the nation in the both the amount and the treatment of Demand Resources that are allowed to participate within the FCM. The Market Rules are continuously under consideration for fine-tuning and revision, with respect to how the Demand Resources will be called upon in the 2011/12 Capability Years and beyond.

The FCM also has a locational component, the LSR, which represents the minimum amount of capacity that must be electrically located within an import-constrained Load Zone to meet resource adequacy requirements, but does not reflect operating security requirements under specific high load and operating contingency conditions. Based on the LSR values documented in this report for the CT and NEMA/Boston Load Zones, the ISO will secure enough resources located within these two zones during the FCA to meet the localized resource adequacy criterion. An MCL was calculated for the export-constrained ME Load Zone which represents the maximum amount of capacity that can be procured from the ME Load Zone to contribute to the ICR.

{ End of Report }