ISO New England Installed Capacity Requirements for the 2008-2009 Capability Year

ISO New England Inc.
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Executive Summary

This report documents New England's monthly Installed Capacity Requirements (IC Requirements) values for the Capability Year beginning June 1, 2008 through May 31, 2009 (2008-2009 Capability Year), as calculated by ISO New England (ISO-NE). ISO-NE's recommended input assumptions, modeling methodology and IC Requirements results were reviewed by the NEPOOL Power Supply Planning Committee (PSPC) and the NEPOOL Reliability Committee (RC) in early 2008. The final values were subsequently approved by the NEPOOL Participants Committee (PC) on March 7, 2008. ISO-NE filed IC Requirements values with the Federal Energy Regulatory Commission (FERC) for approval on March 21, 2008.

The 2008-2009 IC Requirements shown in Table 1 were calculated in accordance with ISO New England Manual 20[1] and ISO New England Market Rule 1[2]. The 2008-2009 IC Requirements values will not be used for establishing the amount of Installed Capacity (ICAP) to be purchased, as in prior years. These IC Requirements values will be used to calculate the annual and monthly ICAP Reserve Margins for use in determining the Unforced Capacity (UCAP) ratings of Demand Resources, Other Demand Resources (ODR) and New York Power Authority (NYPA) contracts. The 2008-2009 IC Requirements will also serve to inform the stakeholders as to the status of New England's resource adequacy in 2008-2009.

This report documents the supporting input assumptions, details of the IC Requirements calculations, and the results and findings for the 2008-2009 Capability Year.

[1] Located on ISO-NE's web site at: http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.
[2] Located on ISO-NE's web site at: http://www.iso-ne.com/regulatory/tariff/sect_3/index.html.

Table 1: 2008-2009 Monthly Peak Load Forecast and IC Requirements (MW)[3]

Month	Monthly Peak Load	IC Requirements
Jun-08	24,700	32,175
Jul-08	27,970	32,158
Aug-08	27,970	32,160
Sep-08	22,060	32,147
Oct-08	19,050	35,735
Nov-08	20,450	35,739
Dec-08	23,030	34,536
Jan-09	23,030	34,527
Feb-09	21,530	34,514
Mar-09	20,560	35,691
Apr-09	17,980	35,646
May-09	20,250	35,679
Annual Resulting Reserves	With HQICCs 15.0%	
	Without HQICCs 10.7%	

[3] Annual Resulting Reserves are shown calculated both with and without reflecting the Hydro-Québec Interconnection Capability Credits (HQICCs).

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Introduction

The Installed Capacity Requirements (IC Requirements) are an ISO projected measure of the installed generating capability that is necessary to satisfy the ISO New England Control Area's total forecasted load requirements and to maintain sufficient reserve capacity to meet reliability standards. More specifically, the IC Requirements are the amount of generating capacity needed to meet the reliability requirements defined for the New England Control Area of disconnecting non-interruptible customers (a loss of load expectation or "LOLE") no more than once in every ten years (an LOLE of 0.1).

This criterion takes into account: the possible levels of peak loads due to weather variations, the impact of assumed capacity resource performance, and the possible load and capacity relief obtainable through the use of ISO-NE Operating Procedure No. 4, *Actions During a Capacity Deficiency* (OP 4).

The IC Requirements are currently established by ISO New England on an annual basis. The IC Requirements for the 2008-2009 Capability Year were developed in conjunction with Stakeholder input. All of the load and resource assumptions needed for input by the Westinghouse/ABB Capacity Model Program (Westinghouse Capacity Model) were reviewed by the NEPOOL Power Supply Planning Committee (PSPC), a technical committee that is a subcommittee of the Reliability Committee (RC), and the ISO. The PSPC and the ISO were able to agree on all assumptions, inputs and projections for calculating the 2008-2009 Capability Year IC Requirements. The IC Requirements and the underlying assumptions used to develop them were reviewed by the Reliability Committee (RC). The RC voted (with none opposed) to recommend that the Participants Committee (PC) support establishing the 2008-2009 Capability Year IC Requirements using the ISO New England's recommended values. The PC considered these IC Requirements and voted to support them. The IC Requirements for the 2008-2009 Capability Year was filed with the Federal Energy Regulatory Commission (FERC) on March 21, 2008.[4]

2008-2009 Installed Capacity Requirements

Table 2 shows the ISO New England calculated Installed Capacity Requirements for the 2008-2009 Capability Year. These IC Requirements values are developed based on load and resource assumptions reviewed and supported by the PSPC.

[4] A copy of the filing is available at http://www.iso-ne.com/regulatory/ferc/filings/2008/index.html.

Table 2: Monthly IC Requirements (MW) for the 2008-2009 Capability Year[5]

Month	Monthly Peak Load	IC Requirements
Jun-08	24,700	32,175
Jul-08	27,970	32,158
Aug-08	27,970	32,160
Sep-08	22,060	32,147
Oct-08	19,050	35,735
Nov-08	20,450	35,739
Dec-08	23,030	34,536
Jan-09	23,030	34,527
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May-09	20,250	35,679
Annual Resulting Reserves	With HQICCs 15.0%	
	Without HQICCs 10.7%	

The Commission-approved Settlement Agreement establishing a Forward Capacity Market (FCM) in New England in Docket No. ER03-563, *et al.*[6] provides a transition period (beginning December 1, 2006, and ending May 31, 2010) during which fixed payments will be made to all installed capacity (ICAP) resources based on their unforced capacity (UCAP) ratings as calculated according to ISO New England Manual 20, Attachment F. Therefore, the 2008-2009 IC Requirements values will not be used for establishing the amount of ICAP to be purchased, as was the case in prior years. However, the IC Requirements values will be used to calculate the Annual and Monthly ICAP Reserve Margins for use in determining the UCAP ratings of Demand Resources, Other Demand Resources (ODR) and New York Power Authority (NYPA) contracts. The 2008-2009 IC Requirements will also serve to inform the stakeholders as to the status of New England's resource adequacy in 2008-2009.

[5] Annual Resulting Reserves are shown calculated both with and without reflecting the Hydro-Québec Interconnection Capability Credits (HQICCs).

[6] *Devon Power, LLC*, 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006). *See also* FCM Settlement Agreement at § VIII.B.

Methodology

Reliability Planning Model

The Westinghouse Capacity Model Program (Westinghouse Capacity Model) developed by Westinghouse Electric Corporation was used to calculate IC Requirements. The program compares, on a weekly basis, the available capacity resources with the load forecast to determine the Loss of Load Probability (LOLP). Summation of the LOLP over the Capability Year (June 2008 – May 2009) gives the Loss of Load Expectation (LOLE). When the LOLE is at 1 day in 10 years on an annual basis, the power system is considered to be at the ISO New England resource planning reliability criterion.

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 operating procedures.
g) The reliability benefits of interconnections with neighboring systems.
a) Other factors as may be appropriate.

IC Requirements Calculation

The New England IC Requirements is calculated using the formula:

Figure 1: IC Requirements Formula

$$Installed\ Capacity\ Requirements\ (ICR) = \left(\frac{Total\ Capacity - Tie\ Benefits - OP4\ VR}{1 + \frac{ALCC}{Ann\ Pk}} \right) + HQICCs - NYPA + Hydro\ Adj$$

Where
- Annual Peak = Annual Peak Load Forecast for Summer 2008
- Total Capacity = Total Monthly Capacity (Sum of all supply resources)
- Tie Benefits = Monthly Tie Reliability Benefits
- OP4 VR = Load Relief from OP 4 Voltage Reduction of Actions 12 & 13
- ALCC = Additional Load Carrying Capability (as determined from the Westinghouse Capacity Model)
- HQICCs = Monthly Hydro-Québec Interconnection Capability Credits
- NYPA = Grandfathered New York Power Authority (NYPA) Contracts
- Hydro Adj = Difference between Daily Cycle Hydro Ratings at 20% and 50% stream flow ratings

The New England IC Requirements formula is designed such that the resulting value is the minimum amount of capacity required to meet ISO New England's reliability criterion of interrupting non-interruptible load, on average, once every ten years. If the actual system, as modeled, is more reliable than the ISO-NE reliability criterion of 1 day in 10 years, an adjustment in the amount of capacity needed or additional load required to attain the reliability criterion is modeled. For the 2008-2009 IC Requirements, the New England system is expected to be more reliable than the reliability criterion necessitates. To adjust for this, the peak load is increased by an amount called the *Additional Load Carrying Capability* (ALCC). When ALCC is used in the IC Requirements calculation, the effect is to bring the entire ISO-NE control area to the annual reliability criterion of 1 day in 10 years.

In the IC Requirements calculation, the Hydro-Québec Interconnection Capability Credits (HQICCs) and New York Power Authority (NYPA) contracts are considered special resources and are not adjusted by the ALCC amount. The Hydro Adjustment takes into account the amount of capacity difference in the ratings between Daily Cycle Hydro (DCH) units at 50% versus 20% stream flow ratings. Table 3 details the monthly calculation details for the IC Requirements.

Table 3: IC Requirements Calculation Details (MW)

	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09
Annual Peak	27,970	27,970	27,970	27,970	27,970	27,970	27,970	27,970	27,970	27,970	27,970	27,970
Total Capacity	35,389	35,389	35,389	35,389	39,108	39,108	37,908	37,908	37,908	39,108	39,108	39,108
Tie Benefits	2,000	2,000	2,000	2,000	2,000	2,000	800	800	800	2,000	2,000	2,000
HQICCs	1,200	1,200	1,200	1,200	1,200	1,200	-	-	-	1,200	1,200	1,200
OP 4 - Action 12 & 13	410	410	410	410	296	296	296	296	296	296	296	296
ALCC	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854	1,854
NYPA Purchase	91	91	91	91	91	91	91	91	91	91	91	91
50% Hydro Rating Adjustment	137	121	122	109	102	106	103	95	82	58	13	47
Installed Capacity Requirements	**32,175**	**32,158**	**32,160**	**32,147**	**35,735**	**35,739**	**34,536**	**34,527**	**34,514**	**35,691**	**35,646**	**35,679**

Assumptions

Table 4 summarizes all of the input assumptions used for the calculation of the IC Requirements. These assumptions are described in detail below.

Table 4: Summary of Input Assumptions

Load Forecast
Existing Capacity
Generating Resources
Demand Response
Other Demand Resources
Capacity Additions
Capacity Attritions
Daily Cycle Hydro Ratings Adjustment
Net of Purchases and Sales
Tie Benefits
Individual Control Area Tie Benefits
HQICCs
OP 4 Load Relief
Operating Reserve
Resource Availability
Generating Resource Forced Outages
Generating Resource Scheduled Outages
Demand Resources Availability

Load Forecast

The New England load forecast used in the Westinghouse Capacity Model is from the April 2008 *Forecast Report of Capacity, Energy, Loads and Transmission (CELT).*[7] The peak load forecasts were developed by ISO-NE using economic and demographic assumptions as reviewed and approved by the NEPOOL Load Forecast Committee (LFC).

The relationship of system peak load to weather is represented by a probability distribution of non-holiday weekday daily peak loads for each week of the year. These weekly distributions are represented in the Westinghouse Capacity Model with three parameters: the expected value (mean), the standard deviation, and the skewness[8] 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 the distribution.

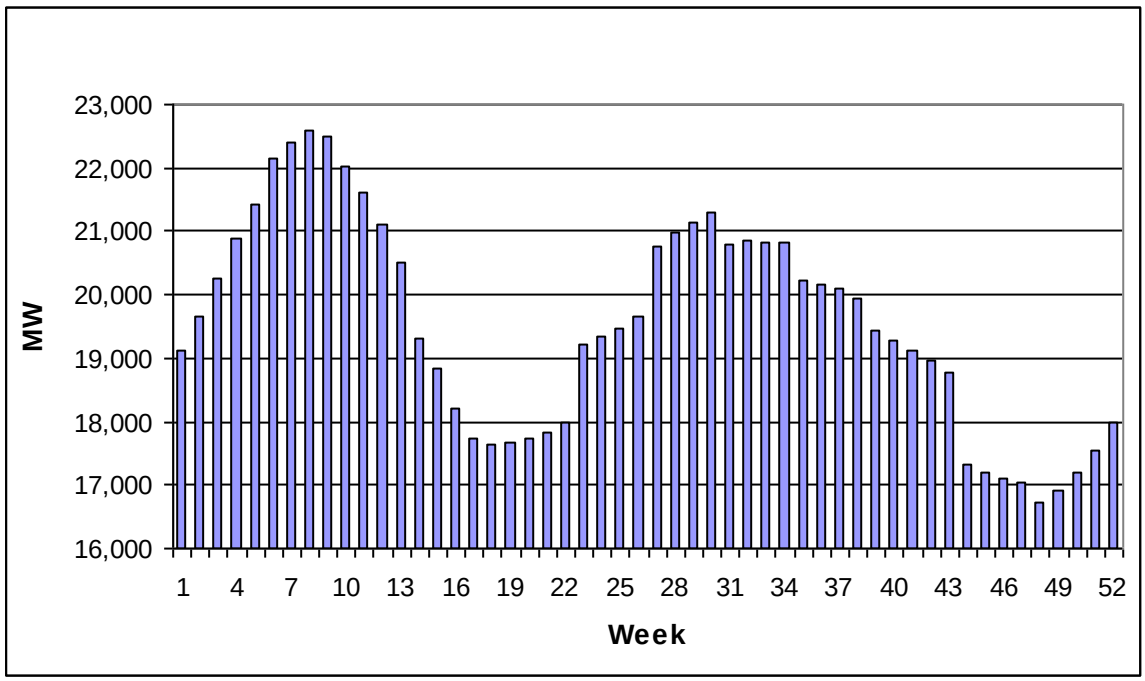
When applied to the load forecast, these three moments of the distribution are used to model the most likely peak forecast (mean), the effect of weather uncertainty (standard deviation), and the frequency of high loads not present in a normal distribution (skewness). Monthly and seasonal peak loads are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

[7] Located on ISO-NE's website at: http://www.iso-ne.com/trans/celt/report/index.html
[8] Skewness is represented in the model by the Third Cumulant which is Skewness*Standard Deviation^3.

curves. For example, both the 50/50 and the 90/10 summer peak load forecast values are points on the curve.

The three charts below show the graphical representation of the weekly mean, standard deviation and skewness of the load forecast distributions. They show that the greatest variation in the forecast distribution occurs during the summer weeks.

Figure 2: Mean of Weekly Forecast Distributions[9]



[9] Week 1 is the first week of June, 2008

Figure 3: Standard Deviation of Weekly Forecast Distributions[10]

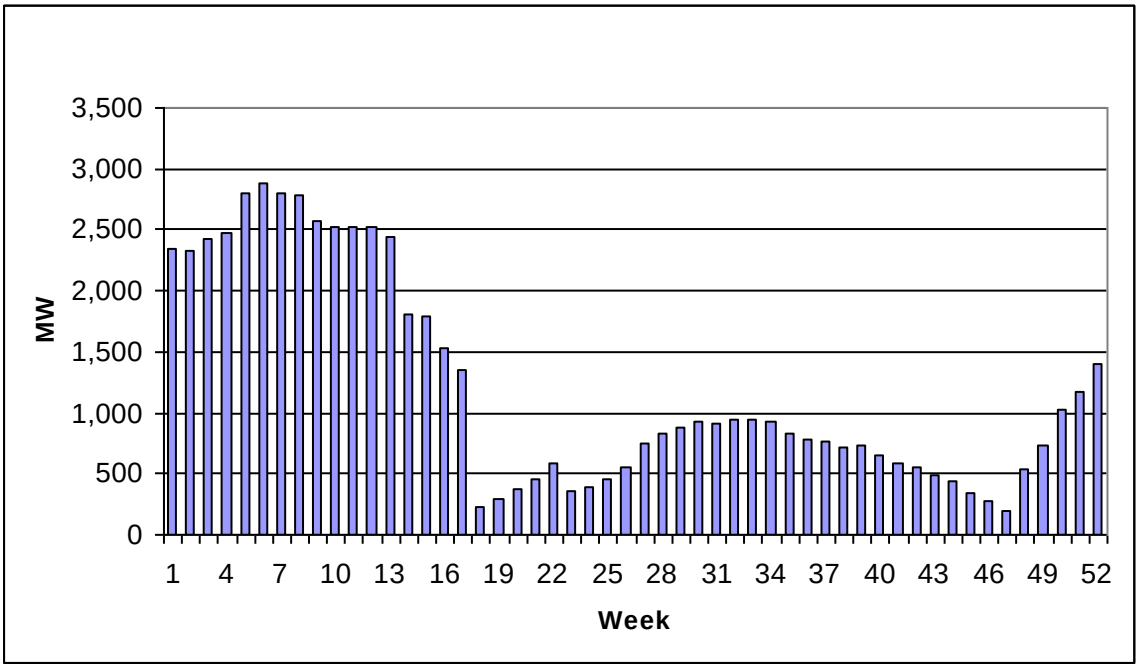
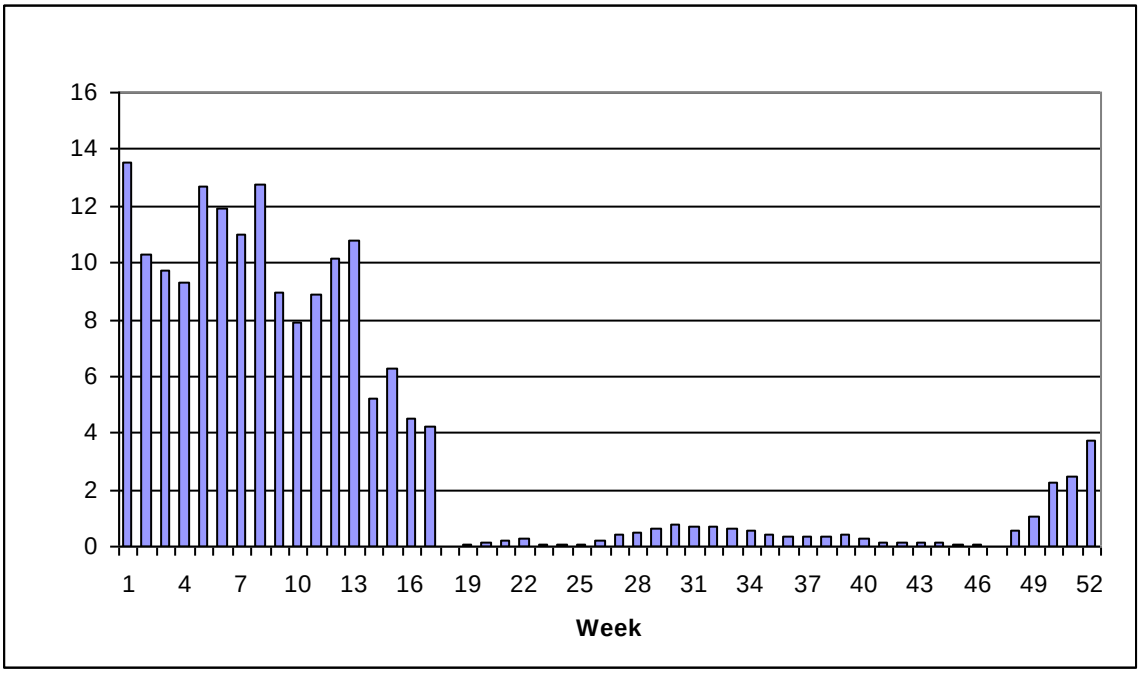


Figure 4: Third Cumulant of Weekly Forecast Distributions[9,11]



[10] Week 1 is the first week of June, 2008

[11]The Third Cumulant is calculated as (Skewness*the cube of the Standard Deviation). Skewness is a unit less measure of a distribution's variation from the mean with positive values indicating variation away from the mean at the high end of the distribution and negative values indicating variation at the low end.

The summer 2008 forecast distribution of peak load is shown in Table 5. The values range from the 10th percentile, representing peak loads with a 10% chance of being exceeded, to the 95th percentile peak load, which has only a 5% chance of being exceeded.

Table 5: Summer 2008 Peak Load Forecast Distribution (MW)

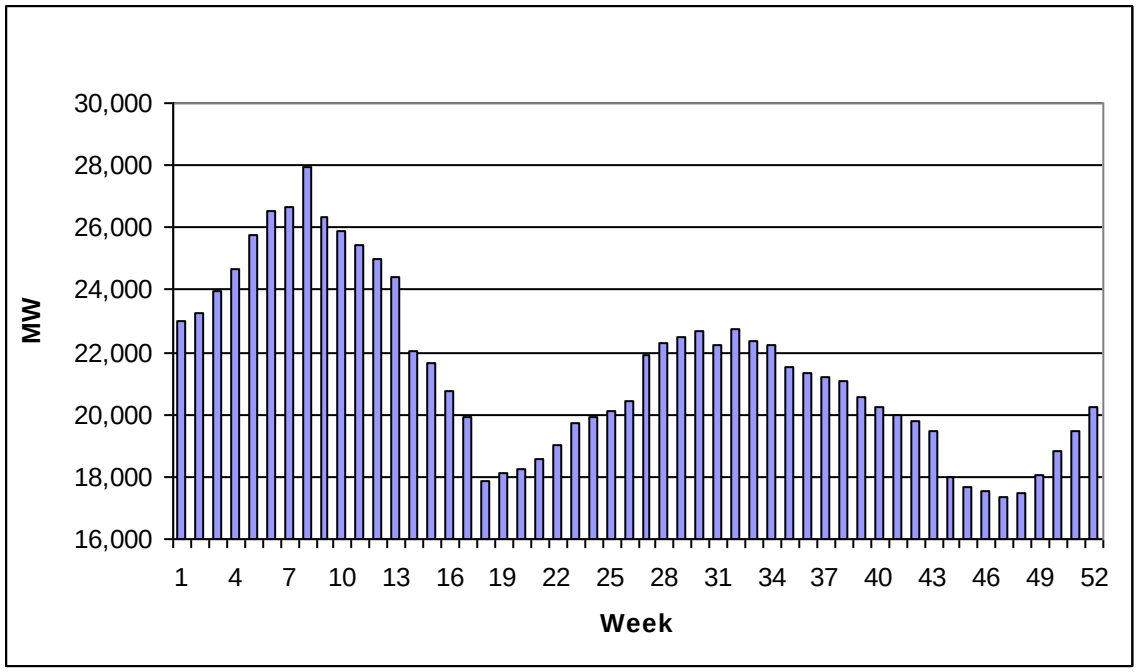
10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
26,650	26,920	27,170	27,580	27,970	28,350	28,680	29,220	29,900	30,450

The monthly peak load forecast for the 2008-2009 Capability Year is shown in Table 6. These values represent the expected value or reference (50/50) case as derived from the 95th percentile of the weekly forecast distributions (reference Figure 5). The median of the forecast distribution is termed the expected value because the realized level is equally likely to fall either above or below the median.[12] The medians are reported to facilitate comparisons, but the inherently uncertain nature of the forecast is modeled by the forecast distributions used as inputs of the Westinghouse Capacity Model.

Table 6: Monthly Peak Load Forecast for the 2008-2009 Capability Year (MW)

Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09
24,700	27,970	27,970	22,060	19,050	20,450	23,030	23,030	21,530	20,560	17,980	20,250

Figure 5: 95th Percentile of the Weekly Peak Load Forecast Distribution[13]



[12] More details on the ISO-NE load forecast assumptions and methodology can be found at: http://www.iso-ne.com/trans/celt/fsct_detail/index.html.

[13] Week 1 is the first week of June, 2008

Existing Capacity

Existing capacity used in the Westinghouse Capacity Model was based on the November 2007 ISO New England *Seasonal Claimed Capability Report* (SCC)[14] and the November 2007 Settlement Markets System Report (SMS)[15]. Table 7 shows the summer and winter capability of generating units summed by categories.

Table 7: Summer & Winter Capability by Generator Category (MW)

Generator Category	Summer	Winter
Combined Cycle	11,044	12,722
Fossil	9,777	10,048
Nuclear	4,548	4,588
Hydro (Includes Pumped Storage)	3,368	3,483
Combustion Turbine	1,951	2,487
Diesel	212	219
Miscellaneous	65	65
Total System	**30,965**	**33,612**

Demand Response

Modeled in the IC Requirements calculation are Demand Response resources in the Reliability Program category. These resources provide real time peak load relief within 30-minutes or 2-hours of a request by ISO New England, during or in anticipation of expected operable capacity shortage conditions, to implement ISO-NE Operating Procedure No. 4, *Actions During a Capacity Deficiency* (OP4). Also included are the profiled resources, which provide relief in under 2-hours but do not have interval meters installed. Demand Resources enrolled in these programs as of November 1, 2007 were used as the starting value to project enrollment of summer 2008 and winter 2008-2009 capacity.

Demand Response performance was measured by actual response during 2007 event response audits which occurred on August 14, 2007 and September 15, 2007. To calculate the percent historical performance, the actual load curtailed or generation provided during such events was divided by the MW of resources enrolled within the program.

The Demand Response resources and their performance ratings modeled in the IC Requirements calculation are shown in Table 8.

[14] This report can be found at: http://www.iso-ne.com/genrtion_resrcs/snl_clmd_cap/index.html.
[15] Available to Market Participants; contact ISO-NE Customer Service at mailto:custserv@iso-ne.com.

Table 8: Demand Response and Historical Performance

	RT 30-min			RT 2-Hr			Profiled			Total	
Zone:	Summer MW	Winter MW	Performance (%)	Summer MW	Winter MW	Performance (%)	Summer MW	Winter MW	Performance (%)	Summer MW	Winter MW
CT	780.7	855.8	54	1.1	1.2	0	0.0	0.0	NA	781.8	857.0
SWCT*	397.9	436.2	49	0.9	1.0	32	0.0	0.0	NA	398.9	437.2
ME	360.7	395.4	100	80.4	88.1	100	12.7	13.9	0	453.8	497.4
NEMA	119.4	130.9	57	0.0	0.0	0	0.0	0.0	NA	119.4	130.9
NH	30.3	33.2	63	2.0	2.2	67	0.0	0.0	NA	32.3	35.4
RI	62.7	68.7	68	5.7	6.3	44	0.0	0.0	NA	68.4	75.0
SEMA	53.7	58.8	47	4.2	4.6	56	0.0	0.0	NA	57.9	63.4
VT	22.5	24.7	74	1.5	1.6	0	6.8	7.5	100	30.8	33.8
WCMA	86.5	94.8	75	22.1	24.3	63	0.0	0.0	NA	108.6	119.1
Total*	1516.4	1662.3		117.0	128.3		19.5	21.4		1653.0	1811.9

* SWCT Resources are also included in the CT values.

Other Demand Resources

Other Demand Resources (ODR) are a Demand Resource group primarily consisting of Energy Efficiency programs. Any realized ODR reductions in the historical period are added back into the historical loads and from these estimated load levels, the forecast of future peak loads are projected. Therefore, the ODR are modeled as a resource in the ICR calculation. The ODR shown in Table 9 were based on historical values from 2007 that were added back into the historical loads (including an 8% transmission and distribution losses adjustment). These ODR are modeled as 100% available.

Table 9: Other Demand Resources (MW)

Load Zone	Summer	Winter
CT	67.47	147.85
ME	14.76	30.45
NEMA	24.44	47.70
NH	10.70	10.05
RI	10.43	13.54
SEMA	14.34	31.32
VT	8.84	14.34
WCMA	16.25	30.94
Total	167.23	326.19

Capacity Additions

IC Requirements assumptions for 2008-2009 include capacity additions based on those generating units with I.3.9 Application approval and under construction as of November 1, 2007. Capacity additions expected to be in-service by the 2008-2009 Capability Year (as indicated by their System Impact Study (SIS) Queue expected in-service date) will be included within the resource capacity mix as shown in the Table 10.

Table 10: Capacity Additions

Project Name	Summer MW	Unit Type	Fuel Type	State	SIS Queue Projected Commercial Operation Date
GMP Essex Diesel	8	IC	Oil	VT	10/31/2007
Covanta Haverhill	1.6	IC	Landfill Gas	MA	11/1/2007
Indeck Alexandria	16.6	ST	Biomass/Wood waste	MA	2/1/2008
Cos Cob Redevelopment	36	GT	Oil	CT	2/1/2008
L'Energia	74	CC	Natural Gas/Oil	MA	6/15/2008
Total	136.2				

Capacity Attritions

There were no capacity attritions assumed for the 2008-2009 Capability Year.

Daily Cycle Hydro Ratings

Daily Cycle Hydro (DCH) units are rated in accordance with ISO New England Manual 20, Attachment D, Supplement B. The DCH capability calculations utilize daily mean river/stream flow rate data over a 20-year historical period. Updated DCH ratings using 20% exceedance flows, i.e. the amount of water flow that is surpassed 20% of the time during the month, went into effect on June 1, 2006. These values were modified for any ratings difference derived from the November 1, 2007 SCC Report which include DCH unit ratings based on 20% exceedance stream flows.

An adjustment from the DCH 20% exceedance flow ratings to 50% flow ratings has historically been made to the IC Requirements to provide an allowance for the expected amount of capacity that is potentially unavailable due to low hydraulic conditions. Table 11 shows the monthly adjustments to the 2008-2009 IC Requirements for the DCH rating difference between the 20% and 50% stream flows.

Table 11: DCH Ratings Adjustment (MW)

	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09
20% Flow Values	951	839	804	796	910	989	986	954	962	1016	1021	1016
50% Flow Values	815	719	682	687	808	883	882	860	881	958	1008	969
Difference	137	121	122	109	102	106	103	95	82	58	13	47

Purchases and Sales

Purchase and Sales for the 2008-2009 IC Requirements calculation were taken from the 2007 CELT Report. The CELT Report includes two purchases from the Hydro-Québec and New York Control Areas for a total of 401 MW in the summer and 1,269 MW in the winter. There were no modeled purchases from the Maritimes Control Area. In addition to the purchases, a 343 MW sale to Long Island Power Authority (LIPA) over the Cross Sound Cable was also modeled. Table 12 reflects the net purchases and sales of 58 MW in the summer and 926 MW in the winter.

Table 12: Purchases and Sales Modeled in the 2008-2009 IC Requirements (MW)

Control Area	Summer	Winter
Hydro Quebec	310	623
Maritimes	0	0
New York	91	646
New York (*via Cross Sound Cable)*	-343	-343
Net Purchases & Sales	58	926

Tie Benefits

The amount of tie benefits used in calculating the 2008-2009 IC Requirements was 2,000 MW for the summer and winter months. This value is based on the 2003 Tie Benefits Study[16] and latest Northeast Power Coordinating Council (NPCC) Resource Adequacy Assessment.[17] The 2,000 MW tie benefit assumption is comprised of 1,200 MW of the Hydro-Québec Interconnection Capability Credits (HQICCs), 600 MW of tie benefits from New York and 200 MW of tie benefits from the Maritimes.

The HQICCs are the values made in an informational filing to FERC on October 31, 2006 and are shown in Table 13.

Table 13: Hydro-Québec Interconnection Capability Credits (MW)

2008/09	HQICCs
June	1,200
July	1,200
August	1,200
September	1,200
October	1,200
November	1,200
December	0
January	0
February	0
March	1,200
April	1,200
May	1,200

In the winter months, tie benefits for New York and the Maritimes were included in the IC Requirements modeling for the 2008-2009 Capability Year. This is a change from last year's IC Requirements calculation assumptions where no tie benefits from New York and the Maritimes in the winter months were assumed.

OP 4 Load Relief

Load relief from ISO-NE Operating Procedure No. 4, *Actions During a Capacity Deficiency* (OP 4), Actions 12 and 13 is also modeled within the IC Requirements

[16] See http://www.iso-ne.com/genrtion_resrcs/reports/nepool_oc_review/2003/index.htm for this report.
[17] See http://www.npcc-cbre.org/documents/reports/Seasonal.aspx for this report.

calculation. 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 5% voltage reduction achievable in 10-minutes or less. Load Relief assumptions are based on results from a system-wide test which are documented in the OP 4 Appendix A, Revision 13, updated on May 21, 2007[18] providing test results as 0.90 % of total system load was able to curtail within the greater than 10-minute period of OP 4 Action 12, while 1.28% of total system load was able to be curtailed for the 10-minute or less category of OP 4 Action 13. The values in Appendix A of OP 4 are converted into percent of peak load and used as multipliers to obtain the 2008-2009 Capability Year OP 4 load relief assumptions.

Table 14 shows the MW amount of voltage reduction modeled from OP 4 Actions 12 & 13.

Table 14: OP 4 Action 12 & 13 Modeled in the 2008-2009 IC Requirements (MW)

	Peak Load	Action 12 5% Voltage Reduction > 10min	Action 13 5% Voltage Reduction < =10min	Total 5% Voltage Reduction from OP4
June – September	27,970	252	358	610
October – May	23,030	205	291	496

Operating Reserve

It is assumed that during peak load conditions with extremely tight capacity situations, ISO-NE System Operation will hold a minimum of 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 IC Requirements calculation by withholding this amount from serving load.

Unit Availability

Forced Outages

A 5-year, historical average of unit-specific forced outage assumptions are determined for each generating unit using a combination of the North American Reliability Council's (NERC) Class Average Equivalent Demand Forced Outage Rate (EFORd) data[19] and New England specific data for EFORd[20] values from NERC's Generating Availability Data System (GADS).

Since NERC GADS data is not available for the earlier portion of the 5-year time period, the NERC Class Average EFORd data is used for the period of December 2002 through

[18] OP 4 Appendix A is available at http://www.iso-ne.com/rules_proceds/operating/isone/op4/op4a_rto_final.pdf.
[19] NERC Class Average Data can be located on the NERC web site at: http://www.nerc.com/.
[20] The calculation methodology of EFORd can be found in ISO-NE Manual 20 at http://www.iso-ne.com/rules_proceds/isone_mnls/index.html.

February 2003. Generator submitted (to ISO-NE) NERC GADS data is used for the period of March 2003 through November 2007.

The New England nuclear generating units, which as a whole have higher availability than the NERC Class Average data for nuclear units, use a different methodology for calculating their 5-year average availability. Instead of using the NERC class average data for nuclear generators, existing Equivalent Forced Outage Rate (EFOR) data as calculated from data submitted to ISO System Operations from New England's nuclear generators is used. This EFOR data differs from the EFORd data by not including generator start-up failures and generator reserve shut-downs as applicable inputs. Nuclear units EFOR and EFORd are similar, since in general, these units are not affected by the differences mentioned above.

Table 15 shows the summer capacity weighted average EFORd values resulting from summing the individual generator data by category and weighting by individual capacity ratings. In the Westinghouse Capacity Model, the calculated EFORd for each individual generator is used as an input.

Table 15: Weighted EFORd by Generator Category

Generator Category	Summer MW	Weighted EFORd
Combined Cycle	11,044	5.2
Fossil	9,777	7.4
Nuclear	4,548	1.3
Hydro (Includes Pumped Storage)	3,368	2.2
Combustion Turbine	1,951	7.7
Diesel	212	4.2
Miscellaneous	65	2.7
Total System	**30,965**	**5.2**

Scheduled Outages

A weekly representation of a generator's scheduled outages is another input into the Westinghouse 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. The table below 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. Table 16 summarizes the maintenance outage assumptions by generator category.

Table 16: Maintenance Outages by Generator Category

Generator Category	Summer MW	Weighted Maintenance Weeks
Combined Cycle	11,044	5.1
Fossil	9,777	4.7
Nuclear	4,548	3.2
Hydro (Includes Pumped Storage)	3,368	2.6
Combustion Turbine	1,951	1.6
Diesel	212	1.0
Miscellaneous	65	0.1
Total System	**30,965**	4.2

Comparison with the 2007-2008 Capability Year IC Requirements

Monthly IC Requirements Values

For the 2008-2009 Capability Year, the IC Requirements increased to 32,160 MW from last year's value of 31,270 MW. This is an increase of 890 MW or approximately 2.8%. The tables shown below document the monthly peak load forecast and IC Requirements for the Capability Years 2008-2009 (Table 17) and 2007-2008 (Table 18). In addition, Figure 6 plots monthly IC Requirements values for both Capability Years.

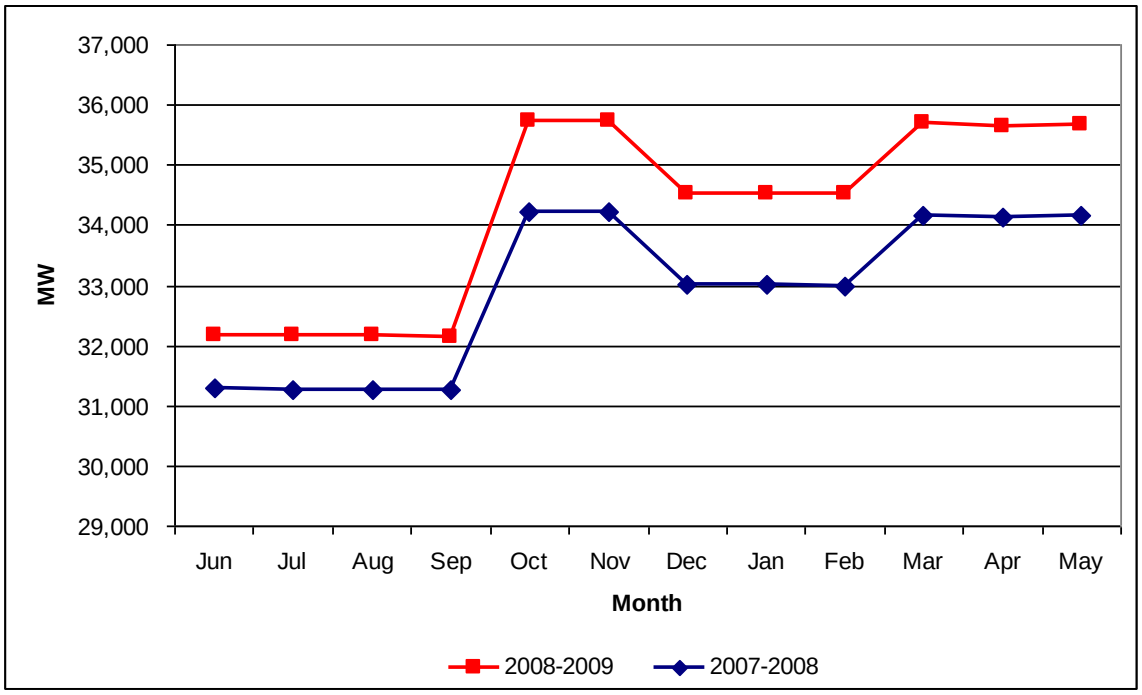
Table 17: Monthly Peak Load Forecast and IC Requirements (MW) for the 2008-2009 Capability Year

Month	Monthly Peak Load	IC Requirements
Jun-08	24,700	32,175
Jul-08	27,970	32,158
Aug-08	27,970	32,160
Sep-08	22,060	32,147
Oct-08	19,050	35,735
Nov-08	20,450	35,739
Dec-08	22,770	34,536
Jan-09	22,370	34,527
Feb-09	21,530	34,514
Mar-09	20,560	35,691
Apr-09	17,980	35,646
May-09	20,250	35,679
Annual Resulting Reserves	With HQICCs 15.0%	
	Without HQICCs 10.7%	

Table 18: Monthly Peak Load Forecast and IC Requirements (MW) for the 2007-2008 Capability Year

Month	Monthly Peak Load	IC Requirements
Jun-07	24,350	31,287
Jul-07	27,360	31,270
Aug-07	27,360	31,272
Sep-07	22,545	31,259
Oct-07	18,660	34,216
Nov-07	20,520	34,217
Dec-07	22,280	33,016
Jan-08	23,070	33,006
Feb-08	21,925	32,996
Mar-08	20,440	34,173
Apr-08	18,075	34,133
May-08	20,375	34,166
Annual Resulting Reserves	With HQICCs 14.3%	
	Without HQICCs 9.9%	

Figure 6: Monthly IC Requirements (MW) for 2007-2008 and 2008-2009



Assumption Comparison

Modeled Assumptions

Table 19 outlines the change in assumptions used in the IC Requirements calculations for this Capability Year with last year's.

Table 19: Assumptions for the 2007-2008 IC Requirements versus 2008-2009 IC Requirements

Assumption	2007–2008 Capability Year		2008–2009 Capability Year	
	Summer	Winter	Summer	Winter
Load Forecast	27,360 MW	23,070 MW	27,970 MW	22,770 MW
Existing Capacity	30,526 MW	33,543 MW	30,965 MW	33,612 MW
Demand Response	580 MW	580 MW	1653 MW	1812 MW
ODR	0 MW		167 MW	326 MW
Capacity Additions	0 MW		136 MW	
Capacity Attrition	0 MW		0 MW	
Purchases & Sales	55 MW	105 MW	58 MW	926 MW
Weighted Equivalent Forced Outage Rates	5.18%		5.17%	
Weighted Average Maintenance Weeks	4.5 Weeks		4.2 Weeks	
Tie Reliability Benefits	600 MW New York	0 MW New York	600 MW New York	600 MW New York
	200 MW Maritimes	0 MW Maritimes	200 MW Maritimes	200 MW Maritimes
HQICCs				
Jun	1200 MW		1200 MW	
Jul	1200 MW		1200 MW	
Aug	1200 MW		1200 MW	
Sep	1200 MW		1200 MW	
Oct	1200 MW		1200 MW	
Nov	1200 MW		1200 MW	
Dec	0 MW		0 MW	
Jan	0 MW		0 MW	
Feb	0 MW		0 MW	
Mar	1200 MW		1200 MW	
Apr	1200 MW		1200 MW	
May	1200 MW		1200 MW	
OP4 Load Relief	509 MW	429 MW	610 MW	496 MW

Daily Cycle Hydro Adjustment

In addition to the assumptions used in the Westinghouse Capacity Model, the DCH hydro adjustment for the 2008-2009 Capability Year has also changed from that used in the previous year's IC Requirements calculation. This is due to the change in DCH generator ratings. Table 20 shows the DCH adjustment for 2007-2008 and 2008-2009 Capability Years.

Table 20: DCH Ratings Adjustment Comparison (MW)

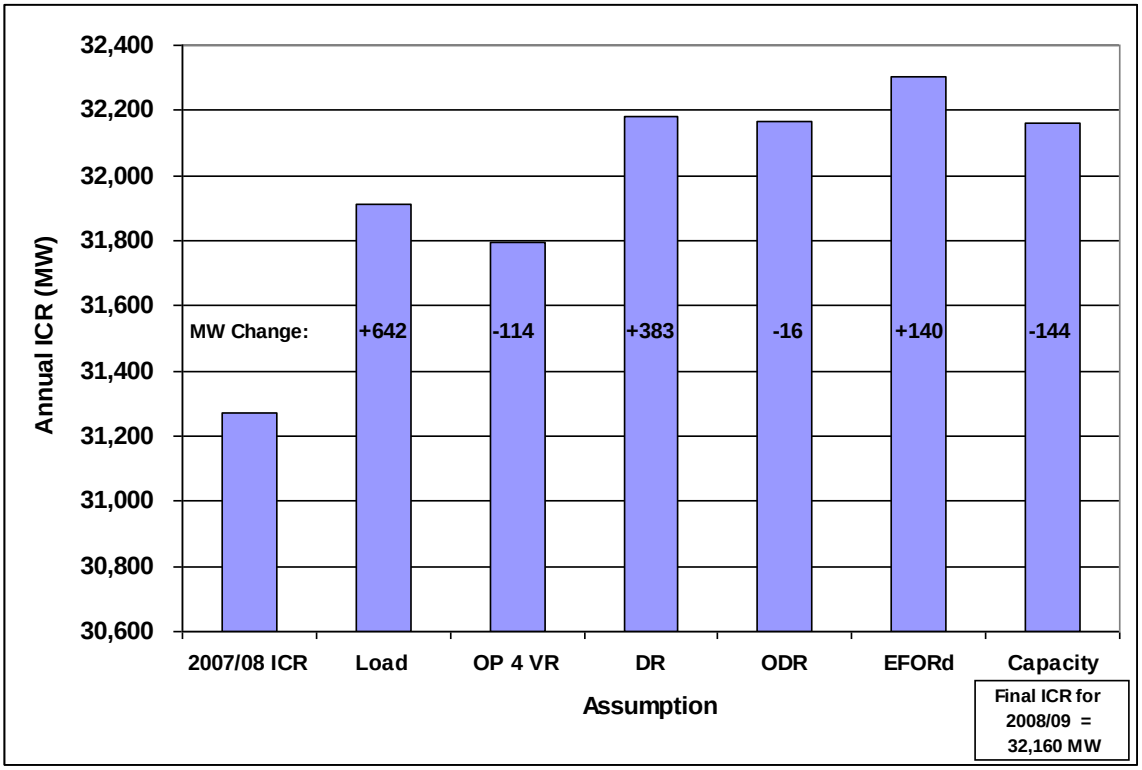
	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
2007-2008	126	109	111	98	98	99	98	88	78	55	15	48
2008-2009	137	121	122	109	102	106	103	95	82	58	13	47

Effect of Assumption Changes

In an effort to quantify the effects that each input assumption has on the IC Requirements, ISO-NE began with the input assumptions associated with the 2007-2008 Capability Year IC Requirements and incrementally updated each (changed) assumption for the 2008-2009 Capability Year. The net of these changes in IC Requirements modeling, as a result from each individual input assumption change was then considered as the overall effect of the changed assumption set.

As shown in Figure 7, the higher forecasted peak load raises the 2008-2009 IC Requirements by 642 MW over the 2007-2008 IC Requirements value. The effect of the OP 4 voltage reduction assumption is -114 MW due to the change in the voltage reduction percentage assumption and also by the effect of applying this assumption to a higher peak load forecast. The Demand Response assumption increases IC Requirements by 383 MW. This is due to the increased amount of these resources which have an assumed availability lower than the system average. Other Demand Resources lower the IC Requirements by 16 MW since these are modeled as 100% available. The combined effect of the EFORd assumption and change in capacity ratings is negligible. When all resource assumptions are updated including the load forecast, OP 4, Demand Response and ODR, EFORd and capacity ratings, and the DCH ratings adjustment, the annual 2008-2009 IC Requirements is 890 MW or 2.8% higher than the IC Requirements value for 2007-2008.

Figure 7: Effect of Assumption Changes on the IC Requirements



{ End of Report }