

Agenda Item 2.5

PSPC Meeting 271

January 14, 2010

Assumptions for the Installed Capacity Requirement (ICR) for the 2013/14 Forward Capacity Auction (FCA4)

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Objective of this Presentation

- Review available load, capacity and transmission assumptions used to simulate the New England bulk power supply system for calculating the Installed Capacity Requirement (ICR) for the 2013/14 Capacity Commitment Period Forward Capacity Auction (FCA4)

2013/14 ICR Tentative Schedule

- PSPC review of assumptions – Feb **11, 2010**
- PSPC review of ISO recommendation of ICR values – **Mar 11, 2010**
- RC review/vote of ISO recommendation of ICR values – **Mar 17, 2010**
- PC review/vote of ISO recommendation of ICR values – **Apr 9, 2010**
- File with the FERC – by **May 2, 2010**
- FCA4 – **Aug 2, 2010**

Assumptions for the ICR Calculation for the 2013/14 FCA

Modeling the New England Control Area

The New England ICR is calculated using a single area LOLE model (Westinghouse Capacity Model Program).

- Internal transmission constraints are not modeled. All loads and resources are assumed to be connected to a single electric bus.
- Internal transmission constraints are addressed through Local Sourcing Requirements and Maximum Capacity Limits.

Assumptions for the 2013/14 ICR

- *Load Forecast*
 - Load Forecast distribution
- *Resource Data*
 - Existing Qualified Generating Capacity Resources
 - Existing Qualified Intermittent Power Capacity Resources
 - Existing Qualified Import Capacity Resources and Known Sales
 - Existing Qualified Demand Resources (DR)
- *Resource Availability*
 - Generating Resources Availability
 - Intermittent Power Resources Availability
 - Demand Resources Availability
- *Load Relief from OP 4 Actions*
 - Tie Reliability Benefits
 - HQICCs
 - Maritimes
 - New York
 - 5% Voltage Reduction

Load Forecast Data

- **Load forecast assumption from the 2010 CELT Report Load Forecast**
- **The load forecast weather related uncertainty is represented by a weekly distribution of daily peak loads for calculating system resource adequacy.**
 - Weekly distributions of daily peak loads represented by the expected value (mean), the standard deviation and the skewness.

Load Forecast Data – New England System Load Forecast

Monthly Peak Load (MW) – 50/50 Forecast

Under Development

There is a distribution associated with each monthly peak. The distribution associated with the Summer Seasonal Peak (July & August) is show below:

Probability Distribution of Annual Peak Load (MW)

Under Development

Resource Data – Existing Qualified Generating Capacity Resources (MW)

Load Zone	Generation		Intermittent		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	3,011.753	3,223.452	236.537	291.579	3,248.290	3,515.031
NEW HAMPSHIRE	4,019.376	4,176.631	158.405	200.229	4,177.781	4,376.860
VERMONT	885.040	947.349	76.293	117.328	961.333	1,064.677
CONNECTICUT	7,965.798	8,347.667	413.891	429.739	8,379.689	8,777.406
RHODE ISLAND	2,603.912	2,949.199	5.889	8.746	2,609.801	2,957.945
SOUTH EAST MASSACHUSETTS	6,010.406	6,484.794	79.115	83.869	6,089.521	6,568.663
WEST CENTRAL MASSACHUSETTS	3,860.992	4,134.103	48.174	68.443	3,909.166	4,202.546
NORTH EAST MASSACHUSETTS & BOSTON	3,271.875	3,704.645	67.753	71.274	3,339.628	3,775.919
Total New England	31,629.152	33,967.840	1,086.057	1,271.207	32,715.209	35,239.047

- Winter Generation values shown for informational purposes, only summer values are modeled.
- Intermittent Resources have both summer and winter values modeled.

Resource Data – Existing Qualified Import Capacity Resources

Resource Name	Interface	Summer Qualified Capacity (MW)	Import Capacity Modeled in ICR (MW)	EFORd (%)
NYPA - CMR	NY AC Ties	68.800	68.800	-
NYPA - VT	NY AC Ties	15.300	15.300	-
VJO - Highgate	HQ Highgate	225.000	194.000	1.00
VJO - Phase I/II	Phase I/II	110.000	39.000	3.00
Lievre River Project - Import	Phase I/II	240.000	240.000	6.43
Erie Boulevard Hydropower - Import	NY AC Ties	697.000	546.439	3.54
Total Imports		1,356.100	1,103.539	3.43

- Resource-backed imports modeled with EFORd based on NERC class average data for large Hydro.
- Total EFORd is the weighted average using the Summer Capacity.
- The VJO contracts will be modeled with delist bids to reflect the value of the firm contract.

Resource Data – Known Sales (MW)

Export	Summer	Winter
LIPA over Cross Sound Cable	100.000	100.000

- Modeled as removed capacity from the resource supplying the export.

Resource Data – Existing Qualified Demand Resources (MW)

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		RT Emergency Gen		Total	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	58.483	55.884	-	-	279.165	297.060	35.023	32.519	372.671	385.463
NEW HAMPSHIRE	61.842	61.225	-	-	45.409	44.613	39.135	37.191	146.386	143.029
VERMONT	71.766	70.988	-	-	33.443	43.409	18.124	17.152	123.333	131.549
CONNECTICUT	115.672	110.337	250.727	250.727	291.940	256.061	298.901	282.985	957.240	900.110
RHODE ISLAND	68.612	67.609	1.727	1.727	51.417	43.277	93.078	81.681	214.834	194.294
SOUTH EAST MASSACHUSETTS	112.545	110.288	1.727	1.727	153.524	137.281	78.961	66.857	346.757	316.153
WEST CENTRAL MASSACHUSETTS	94.516	92.013	19.188	19.188	142.505	119.715	100.221	86.314	356.430	317.230
NORTH EAST MASSACHUSETTS & BOSTON	208.904	205.942	-	-	254.596	224.063	148.989	128.791	612.489	558.796
Total New England	792.340	774.286	273.369	273.369	1251.999	1165.479	812.432	733.490	3130.140	2946.624

- The DR capacity modeled in the ICR is the Summer Existing Qualified DR Capacity by Load Zone for FCA4.
- The Qualified Capacity rating of DR includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%.

Availability Assumptions - Generating Resources

- **Forced Outages Assumption**

- Each generating unit's Equivalent Forced Outage Rate on Demand (non-weighted EFORd) modeled
- Based on a 5-year average (December 2004 – November 2009) of generator submitted Generation Availability Data System (GADS) data
- NERC GADS Class average data will be used for immature units

- **Scheduled Outage Assumption**

- Each generating unit weeks of Maintenance modeled
- Based on a 5-year average (January 2005 – December 2009) of each generator's actual historical average of planned and maintenance outages scheduled at least 14 days in advance
- NERC GADS Class average data will be used for immature units

Availability Assumptions - Generating Resources

Resource Category	Summer MW	Assumed Average EFORd Weighted by Summer Ratings	Assumed Average Maintenance Weeks Weighted by Summer Ratings
Combined Cycle	11,385	4.6	5.8
Fossil	9,333	7.2	4.3
Nuclear	4,629	1.4	3.1
Hydro (Includes Pumped Storage)	3,027	1.9	2.6
Combustion Turbine	2,914	6.7	2.0
Diesel	226	5.7	1.0
Miscellaneous	115	7.5	5.0
Total System	31,629	4.9	4.3

- Assumed summer MW weighted EFORd and Maintenance Weeks are shown by resource category for informational purposes. In the LOLE simulations, individual unit values are modeled.

Availability Assumptions - Intermittent Power Resources

- Intermittent Power Resources are modeled as 100% available since their outages have been incorporated in their 5-year historical output used in their ratings determination.

Availability Assumptions - Demand Resources

Under Development

OP 4 Assumptions - Tie Reliability Benefits (MW)

- Results of the 2010 Tie Benefits study for 2013/14
- Modeled with Forced Outage assumptions of 3% for Québec, 1% for Maritimes, and 0% for New York due to tie line availability.

OP 4 Assumptions - Action 6 and 8 Voltage Reduction (%)

See previous presentation on OP 4 Voltage Reduction



Questions?