Proposed Installed Capacity Requirement (ICR) Values for the 2019/20 Forward Capacity Auction (FCA10)

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Objective of this Presentation

- Review the ICR development and FERC filing schedules
- Review the proposed ICR Values* including:
  - Installed Capacity Requirement (ICR),
  - *For the Southeast New England (SENE) Capacity Zone*
    - Transmission Security Analysis (TSA),
    - Local Resource Adequacy Requirement (LRA),
    - Local Sourcing Requirement (LSR)
  - Indicative Maximum Capacity Limit (MCL) for Northern New England (NNE)**
  - Capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve)

*The ICR, LSR, MCL and the Demand Curve capacity requirements are collectively the ICR Values

**At the 8/14/2015 PSPC Meeting ISO-NE presented an analysis showing that NNE will not be a Capacity Zone for FCA10. The indicative MCL for NNE used in the analysis will be presented today.

ICR Review and Revised FERC Filing Schedule

- ICR for 2019/20 Forward Capacity Auction (FCA10)
  - PSPC to review Capacity Zone determinations – **Jun 30 and Aug 14, 2015**
  - PSPC final review of all assumptions – **Jul 23, 2015**
  - PSPC review of ISO recommendation of ICR Values – **Aug 27, 2015**
  - RC review/vote of ISO recommendation of ICR Values – **Sep 15, 2015**
  - PC review/vote of ISO recommendation of ICR Values – **Oct 2, 2015**
  - File with the FERC – by **Nov 10, 2015**
  - FCA10 begins – **Feb 8, 2016**

PROPOSED ICR VALUES FOR THE 2019/20 FCA

ISO Proposed ICR Values for the 2019/20 FCA (MW)

2019/20 FCA	New England	Southeast New England
Peak Load (50/50)	29,861	12,282
Existing Capacity Resources*	33,484	11,194
Installed Capacity Requirement	35,126	
NET ICR (ICR Minus 975 MW HQICCs)	34,151	
1-in-5 LOLE Demand Curve capacity value	33,076	
1-in-87 LOLE Demand Curve capacity value	37,053	
Local Sourcing Requirements		10,028

- Existing Capacity Resources consists of capacity resources used in the ICR Values calculation.
- In addition to the Existing Capacity Resources shown, 800 MW of proxy units are required for the ICR calculation and 3,600 MW for the 1-in-87 LOLE Demand Curve capacity requirement value calculation.

Comparison of ICR Values (MW) - 2019/20 Vs 2018/19 FCA

	New England		Southeast New England	
	2019/20 FCA	2018/19 FCA	2019/20 FCA	2018/19 FCA
Peak Load (50/50)	29,861	30,005	12,282	-
Existing Capacity Resources*	33,484	32,842	11,194	-
Installed Capacity Requirement	35,126	35,142		
NET ICR (ICR Minus HQICCs)	34,151	34,189		
1-in-5 LOLE Demand Curve capacity value	33,076	33,132		
1-in-87 LOLE Demand Curve capacity value	37,053	37,027		
Local Resource Adequacy Requirement			9,584	-
Transmission Security Analysis Requirement			10,028	-
Local Sourcing Requirement			10,028	-

- Existing Capacity Resources consists of capacity resources used in the ICR Values calculation.
- In addition to the Existing Capacity Resources shown, 800 MW of proxy units are required for the ICR calculation and 3,600 MW for the 1-in-87 LOLE Demand Curve capacity requirement value calculation.

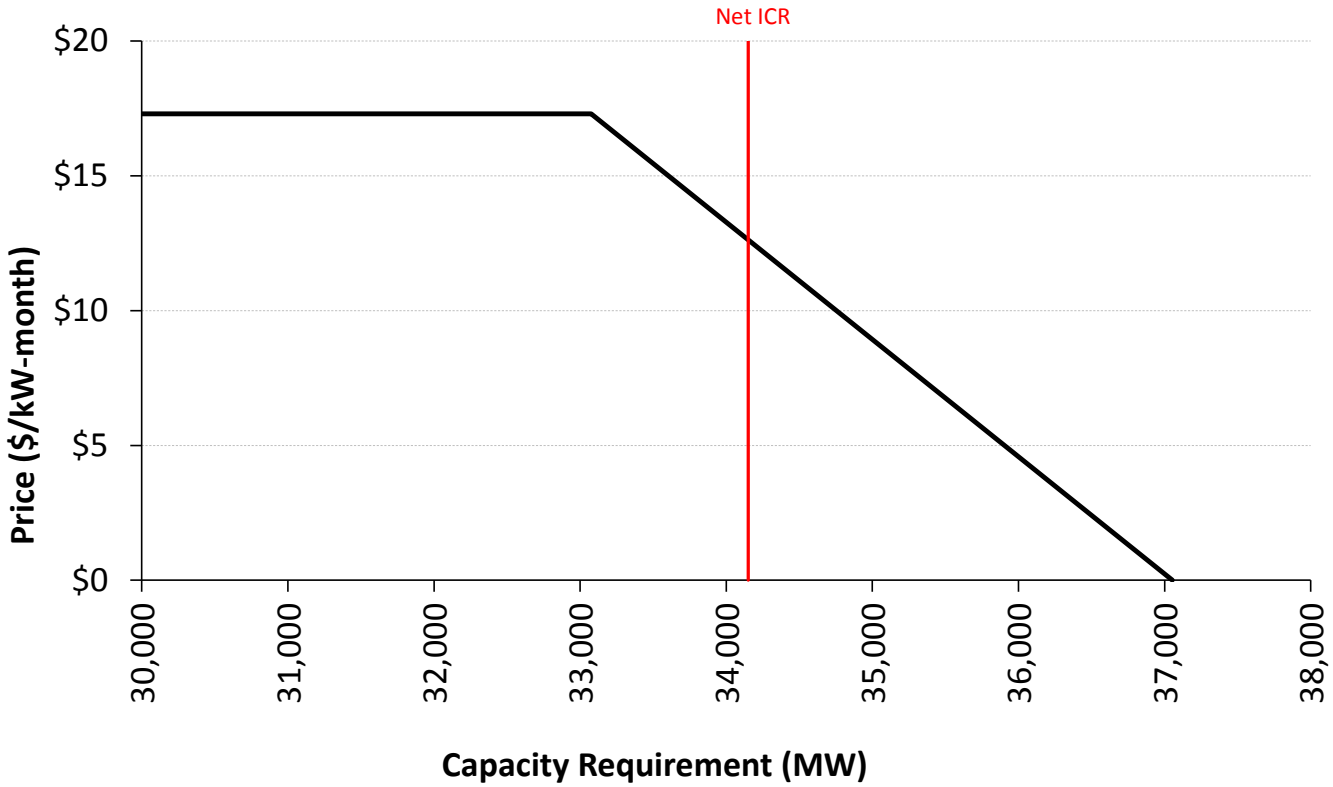
ICR Calculation Details

Total Capacity Breakdown	1-in-5	2019/20 FCA ICR	1-in-87
Generating Resources	30,654	30,654	30,654
Tie Benefits	1,990	1,990	1,990
Imports/Sales	(41)	(41)	(41)
Demand Resources	2,871	2,871	2,871
OP4 - Action 6 & 8 (Voltage Reduction)	442	442	442
Minimum Reserve Requirement	(200)	(200)	(200)
Proxy Unit Capacity	-	800	3,600
Total Capacity	**35,716**	**36,516**	**39,316**
Installed Capacity Requirement Calculation Details	**1-in-5**	**2019/20 FCA ICR**	**1-in-87**
Annual Peak	29,861	29,861	29,861
Total Capacity	35,716	36,516	39,316
Tie Benefits	1,990	1,990	1,990
HQICCs	975	975	975
OP4 - Action 6 & 8 (Voltage Reduction)	442	442	442
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	368	116	25
Installed Capacity Requirements	**34,051**	**35,126**	**38,028**
Net ICR	**33,076**	**34,151**	**37,053**
Reserve Margin with HQICCs	14.0%	17.6%	27.3%
Reserve Margin without HQICCs	10.8%	14.4%	24.1%

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

- All values in the table are in MW except the Reserve Margin shown in percent.
- ALCC is the “Additional Load Carrying Capability” used to bring the system to the target Reliability Criterion.

System-Wide Capacity Demand Curve for FCA10



Cap [1-in-5 LOLE Demand Curve capacity value = 33,076 MW, $17.296]

Foot [1-in-87 LOLE Demand Curve capacity value = 37,053 MW, $0]

Effect of Updated Assumptions on ICR

Assumption	2019/2020 FCA		2018/2019 FCA		Effect on ICR (MW)
Tie Benefits	354 MW New York		346 MW New York		8
	519 MW Maritimes		523 MW Maritimes		
	975 MW Quebec (HQICCs)		953 MW Quebec (HQICCs)		
	142 MW Quebec via Highgate		148 MW Quebec via Highgate		
Total	1,990 MW*		1,970 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	30,524	6.7%	29,699	6.5%	136
Demand Resources	2,871	2.5%	3,054	4.0%	-42
Imports	89	0.0%	89	0.0%	-
	MW		MW		
Load Forecast - Reference	29,861		30,005		-56
	MW	%	MW	%	
OP 4 5%VR	442	1.50%	441	1.50%	-
	MW		MW		
ICR	35,126		35,142		-16

- Methodology: Begin with model for the 2018/19 FCA ICR calculation. Change one assumption at a time and note the change in ICR caused by each change in assumption.

* The difference in Net ICR (ICR minus HQICCS) due to the change in tie benefits is -14 MW.

Load Forecast Assumption Comparisons (MW)

	2015 CELT Load Forecast for 2019/2020	2014 CELT Load Forecast for 2018/2019	Effect on ICR (MW)
Load Forecast - Gross	30,230	30,005	323

	2015 CELT Load Forecast for 2018/2019	2014 CELT Load Forecast for 2018/2019	Effect on ICR (MW)
Load Forecast - Gross	29,825	30,005	-132

	2018/19 with 2015 CELT Load Forecast Uncertainty	2018/19 with 2014 CELT Load Forecast Uncertainty	Effect on ICR (MW)
Load Forecast - Gross	30,005	30,005	154

	2019/20 Reference Load Forecast (Net of BTMNEL PV)	2019/20 Gross Load Forecast	Effect on ICR (MW)
Net BTMNEL LF Vs. Gross LF	29,861	30,230	-392

- Methodology: Begin with model for the 2018/19 FCA ICR model. Change the load forecast assumptions and note the change in ICR.
- These comparisons attempt to gauge the change in ICR attributed to the load forecast: such as year over year change, level change in the load forecast, load forecast uncertainty and the effect of incorporating the reduction in the load forecast for Photovoltaic resources.
- The 50/50 peak load forecasts shown here are to aid in comparisons; the models see a distribution of weekly peak loads and corresponding load forecast uncertainty for each CELT load forecast.

LRA – SENE

Local Resource Adequacy Requirement - SENE			
Southeast New England Capacity Zone		**2019/20 FCA**	**2018/19 FCA**
$Resource_z$	[1]	11,194	-
$Proxy\ Units_z$	[2]	0	-
$Firm\ Load\ Adjustment_z$	[3]	1,482	-
FOR_z	[4]	0.079	-
LRA_z	[5]=[1]+[2]-([3]/(1-[4]))	**9,584**	**-**
Rest of New England Zone			
Resource	[6]	22,290	-
Proxy Units	[7]	800	-
Firm Load Adjustment	[8] = -[3]	-1,482	-
Total System Resource	[9]=[1]+[2]-[3]+[6]+[7]-[8]	34,284	-

- All values in the table are in MW except the FORz

Indicative MCL - NNE

Local RA Requirement - RestofNewEngland (for NNE MCL calculation)			
Rest of New England Zone		**2019/20 FCA**	**2018/19 FCA**
$Resource_z$	[1]	25,220	-
$Proxy\ Units_z$	[2]	800	-
$Surplus\ Capacity\ Adjustment_z$	[3]	106	-
$Firm\ Load\ Adjustment_z$	[4]	521	-
FOR_z	[5]	0.071	-
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**25,345**	**-**
NNE Zone			
Resource	[7]	8,264	-
Proxy Units	[8]	0	-
$Surplus\ Capacity\ Adjustment_z$	[9]	-106	-
Firm Load Adjustment	[10] = -[4]	-521	-
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,284	-

Maximum Capacity Limit - NNE			
Commitment Period		**2019/20 FCA**	**2018/19 FCA**
NICR for New England*	[1]	34,175	-
$LRA_{RestofNewEngland}$	[2]	25,345	-
$Maximum\ Capacity\ Limit_Y$	[3]=[1]-[2]	**8,830**	**-**

- At the 8/14/2015 PSPC Meeting ISO-NE presented an analysis showing that NNE will not be a Capacity Zone for FCA10. See: http://www.iso-ne.com/static-assets/documents/2015/08/pspc_081415_a3.0_fca10_zone_formation2.pdf.
- *The Net ICR value shown is calculated with tie benefits assuming NNE as an export-constrained zone.
- The North-South transmission transfer capability export limit used in the analysis is 2,675 MW
- All values in the table are in MW except the FORz

Cost of New Entry (CONE)

- for the System-Wide Capacity Demand Curve

- CONE for the Cap of the System-Wide Capacity Demand Curve for FCA10 has been calculated as:
  - Gross CONE = $14.29/kW-month
  - Net CONE = $10.81/kW-month
- Price cap of the Demand Curve is determined as:

  Max (1.6 x Net CONE, Gross CONE)
- Price at the Demand Curve Cap = $17.296/kW-month

Questions

ASSUMPTIONS FOR CALCULATING THE ICR VALUES FOR THE 2019/20 FCA

Modeling the New England Control Area

The GE MARS model is used to calculate the ICR and Related Values

- Internal transmission constraints are not modeled in the ICR calculation. All loads and resources are assumed to be connected to a single electric bus.
- Internal transmission constraints are addressed through LSR and MCL
- LSR was calculated for the combined Load Zones of NEMA/Boston, SEMA and RI (Southeast New England (SENE) Capacity Zone).
- An indicative MCL was calculated for the combined Maine, New Hampshire and Vermont Load Zones (Northern New England (NNE)) as a final step in the review of Capacity Zone determination. The NNE combined zones will not be modeled as a Capacity Zone for FCA10 because NNE did not meet the export-constrained Capacity Zone Objective Criteria.
- The Demand Curve capacity values are the capacity requirement values net of Hydro-Quebec Interconnection Capability Credits (HQICCs) at the cap and foot of the System-Wide Capacity Demand Curve and are calculated at 1-in-5 Loss of Load Expectation (LOLE) and 1-in-87 LOLE, respectively.

Assumptions for the ICR Calculations

- *Load Forecast*
  - Load Forecast distribution
  - Net of Behind the Meter not Embedded in the Load Forecast (BTMNEL) Photovoltaic (PV) resource forecast
- *Resource Data Based on Existing Qualified Capacity Resources for FC10 (reflects terminations which occurred in June 2015)*
  - Generating Capacity Resources
  - Intermittent Power Capacity Resources (IPR)
  - Import Capacity Resources
  - Demand Resources (DR)
- *Resource Availability*
  - Generating Resources Availability
  - Intermittent Power Resources Availability
  - Demand Resources Availability
- *Load Relief from OP 4 Actions*
  - Tie Reliability Benefits
    - Quebec
    - Maritimes
    - New York
  - 5% Voltage Reduction

Load Forecast Data

- **Load forecast assumption from the 2015 CELT Report Load Forecast**

- **The load forecast weather related uncertainty is represented by specifying a series of multipliers on the peak load and the associated probabilities of each load level occurring**
  - derived from the 52 weekly peak load distributions described by the expected value (mean), the standard deviation and the skewness.

Modeling of PV in ICR (MW)

Month	2019/2020
Jun	367.1
Jul	369.2
Aug	371.4
Sep	373.8
Oct	0
Nov	0
Dec	0
Jan	0
Feb	0
Mar	0
Apr	0
May	389.3

- Table shows the monthly sum of Seasonal Claimed Capability (SCC) of BTMNEL PV resources modeled in ICR (includes 8% Transmission & Distribution Gross-up)
- Developed using 40%* of PV nameplate forecast from the Distributed Generation Forecast Working Group (DGFWG)
- Modeled as a load modifier in GE MARS by Regional System Plan (RSP) 13-subarea representation for hours ending 14:00 – 18:00

* 40% value based on 3 years of historical PV resource ratings during reliability hours

Load Forecast Data – New England System Load Forecast

Monthly Peak Load (MW) – 50/50 Forecast

Year	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May
2019/20	26,508	29,861	29,861	24,276	19,190	20,955	23,430	23,430	22,160	20,370	18,410	21,021

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)

Year	10/90	20/80	30/70	40/60	50/50	60/40	70/30	80/20	90/10	95/5
2019/20	28,686	28,951	28,996	29,406	29,861	30,341	30,831	31,541	32,341	33,051

- Corresponds to the reference forecast labeled"*1.2 REFERENCE - With reduction for BTM PV"* from section 1.1 of the 2015 CELT Report

Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generation		Intermittent Generation		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	2,863.774	3,018.330	292.832	401.878	3,156.606	3,420.208
NEW HAMPSHIRE	4,043.605	4,267.015	157.295	215.912	4,200.900	4,482.927
VERMONT	222.098	262.716	71.780	124.302	293.878	387.018
CONNECTICUT	9,063.732	9,543.325	172.684	188.939	9,236.416	9,732.264
RHODE ISLAND	1,867.339	2,069.400	3.372	5.220	1,870.711	2,074.620
SOUTH EAST MASSACHUSETTS	4,683.952	5,110.589	83.314	78.057	4,767.266	5,188.646
WEST CENTRAL MASSACHUSETTS	3,732.636	3,986.982	66.670	97.066	3,799.306	4,084.048
NORTH EAST MASSACHUSETTS & BOSTON	3,227.714	3,649.635	71.172	72.260	3,298.886	3,721.895
Total New England	**29,704.850**	**31,907.992**	**919.119**	**1,183.634**	**30,623.969**	**33,091.626**

- Existing Qualified generating capacity resources for FCA10
- Intermittent resources have both summer and winter values modeled; non-Intermittent winter values provided for informational purpose
- Reflects the terminations of resources in early June and a 30 MW derating to reflect the firm contract value of the Vermont Joint Owners (VJO) capacity import

Resource Data – Import Capacity Resources (MW)

Import Resource	Qualified Summer MW	External Interface
VJO - Highgate	6.000	Hydro-Quebec Highgate
NYPA - CMR	68.800	New York AC Ties
NYPA - VT	14.000	New York AC Ties
Total MW	88.800	

- Existing Qualified Import capacity resources for FCA10
- A 30 MW derating is applied to Citizens Block Load (modeled as a generator) to reflect the value of the VJO contract
- All are system-backed imports modeled with 100% resource availability

Resource Data – Export Delist (MW)

Export	Summer MW
LIPA via CSC	100.000

- Based on Administrative Delist Bid
- Modeled as removed capacity from the resource supplying the export

Resource Data – 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	164.811	162.115	-	-	149.386	167.281	7.482	5.198	321.679	334.594
NEW HAMPSHIRE	101.215	80.645	-	-	12.798	12.078	14.022	12.045	128.035	104.768
VERMONT	120.090	111.095	-	-	31.900	39.833	4.918	4.357	156.908	155.285
CONNECTICUT	78.815	56.637	371.437	341.026	77.374	75.541	52.941	52.427	580.567	525.631
RHODE ISLAND	197.599	187.599	-	-	60.362	56.831	15.720	11.329	273.681	255.759
SOUTH EAST MASSACHUSETTS	292.685	259.806	-	-	51.987	50.112	12.722	12.722	357.394	322.640
WEST CENTRAL MASSACHUSETTS	293.340	266.117	49.645	33.939	58.684	53.826	25.098	24.544	426.767	378.426
NORTH EAST MASSACHUSETTS & BOSTON	548.466	506.968	-	-	67.329	67.329	10.439	10.211	626.234	584.508
Total New England	1,797.021	1,630.982	421.082	374.965	509.820	522.831	143.342	132.833	2,871.265	2,661.611

- Existing Qualified Demand Resource capacity for FCA10
- Includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%
- Reflects terminations of resources in early June

LRA, TSA & MCL Internal Transmission Transfer Capability Assumptions (MW)

- Transfer Limits – 2015 Regional System Plan (RSP) for 2019/20
  - Internal Transmission Transfer Capability
    - Southeast New England Import
      - N-1 Limit: 5,700 MW
      - N-1-1 Limit: 4,600 MW
    - North-South interface (for NNE export)*
      - N-1 Limit: 2,675 MW

Includes:

- the New England East West Solution (NEEWS) Interstate Reliability Program – the certification of this project to be in service by December 2015 has been accepted by ISO New England
- the Greater Boston Upgrades - the certification of this project to be in service by June 2019 has been accepted by ISO New England
- upgrades to Rhode Island facilities which are certified for FCA10 in response to the Brayton Point retirement

* Used to calculate indicative MCL for the Capacity Zone Trigger Analysis for NNE

Sub-area Resource and 50/50 Peak Load Forecast Assumptions Used in LRA and MCL Calculations (MW)

Resource Type	Southeast New England (SENE)	Northern New England (NNE) for Indicative MCL	Total New England
Generator	9,779.005	7,129.477	29,604.850
Intermittent Generator	157.858	521.907	919.119
Import		6.000	88.800
On-Peak DR	1,038.750	386.116	1,797.021
Seasonal-Peak DR	-	-	421.082
Real-Time DR	179.678	194.084	509.820
Real-Time Emergency Gen DR	38.881	26.422	143.342
Total	11,194.172	8,264.006	33,484.034

	SENE	NNE	New England
50/50 Load Forecast Net BTMNEL PV	12,282	5,872	29,861

- Generating resource assumptions are based on the RSP sub-areas, used as a proxy for the Load Zones as the transmission transfer capability is determined using the RSP 13 sub-areas. DR values are the Load Zone values.
- Generating resources for New England reflects the 100 MW export and 30 MW derating to reflect the value of the firm VJO contract
- For the SENE Capacity Zone and the indicative MCL analysis for NNE, the sum of the Load Zone resources equals the corresponding RSP sub-areas. The 50/50 load forecast value shown is the sum of the corresponding RSP sub-areas.

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 (Jan 2010 – Dec 2014) of generator submitted Generation Availability Data System (GADS) data
  - NERC GADS Class average data is used for immature units

- **Scheduled Outage Assumption**
  - Each generating unit weeks of Maintenance modeled
  - Based on a 5-year average (Jan 2010 – Dec 2014) of each generator's actual historical average of planned and maintenance outages scheduled at least 14 days in advance
  - NERC GADS Class average data is 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	13,279	4.0	5.4
Fossil	6,087	15.9	5.1
Nuclear	4,024	2.5	4.5
Hydro (Includes Pumped Storage)	2,903	4.9	4.4
Combustion Turbine	3,171	9.4	2.5
Diesel	190	7.3	1.0
Miscellaneous	51	16.1	3.8
Total System	29,705	6.9	4.8

- 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.

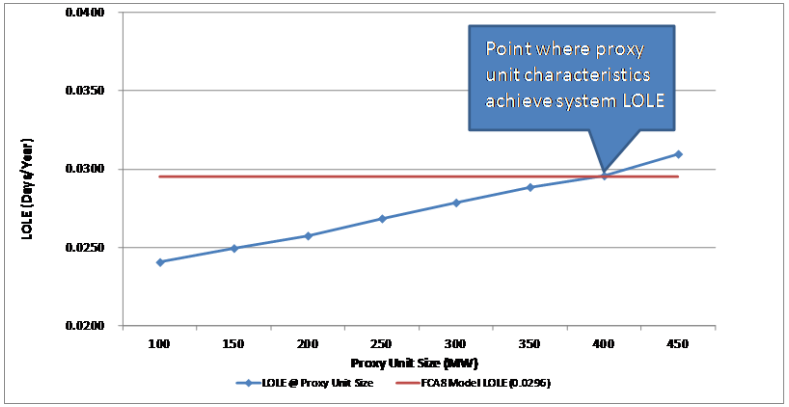
Demand Resource Availability

Load Zone	On-Peak		Seasonal Peak		RT Demand Response		RT Emergency Gen		Total	
	Summer (MW)	Perform-ance	Summer (MW)	Perform-ance	Summer (MW)	Perform-ance	Summer (MW)	Perform-ance	Summer	Perform-ance
MAINE	164.811	100%	-	-	149.386	99%	7.482	92%	321.679	99%
NEW HAMPSHIRE	101.215	100%	-	-	12.798	88%	14.022	97%	128.035	98%
VERMONT	120.090	100%	-	-	31.900	97%	4.918	82%	156.908	99%
CONNECTICUT	78.815	100%	371.437	100%	77.374	83%	52.941	87%	580.567	97%
RHODE ISLAND	197.599	100%	-	-	60.362	83%	15.720	91%	273.681	96%
SOUTH EAST MASSACHUSETTS	292.685	100%	-	-	51.987	78%	12.722	83%	357.394	96%
WEST CENTRAL MASSACHUSETTS	293.340	100%	49.645	100%	58.684	90%	25.098	89%	426.767	98%
NORTH EAST MASSACHUSETTS & BOSTON	548.466	100%	-	-	67.329	83%	10.439	90%	626.234	98%
Total New England	1797.021	100%	421.082	100%	509.820	89%	143.342	89%	2,871.265	97%

- Uses historical DR performance from summer & winter 2010 – 2014. See presentation at: http://www.iso-ne.com/static-assets/documents/2015/05/2015_DR_availability.pdffor more information.
- Modeled by zones and type of DR with outage factor calculated as 1- performance/100

Proxy Unit Characteristics

- Proxy unit characteristics based on a study conducted in 2014 using the 2017/18 FCA8 ICR Model
- Current proxy unit characteristics:
  - Proxy unit size equal to 400 MW
  - EFORd of proxy unit = 5.47%
  - Maintenance requirement = 4 weeks



- Proxy unit characteristics are determined using the average system availability and a series of LOLE calculations. By replacing all system capacity with the correct sized proxy units, the system LOLE and resulting capacity requirement unchanged.

  - The 2014 Proxy Unit Study was reviewed at the May 22, 2014 PSPC Meeting and is available at: http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/may222014/proxy_unit_2014_study.pdf

OP 4 Assumptions
- Action 6 & 8 - 5% Voltage Reduction (MW)

	90-10 Peak Load	Passive DR	RTDR	RTEG	Action 6 & 8 5% Voltage Reduction
Jun 2019 - Sep 2019	32,341	2,218	510	143	442
Oct 2019 - May 2020	24,085	2,006	523	133	321

- Uses the 90-10 Peak Load Forecast minus BTMNEL PV and all Passive & Active DR
- Multiplied by the 1.5% value used by ISO Operations in estimating relief obtained from OP4 voltage reduction

OP 4 Assumptions - Tie Benefits (MW)

- Based on the results of the 2019/20 Tie Benefits Study (with NNE not a zone)

Control Area	2019/20 FCA10
Québec via Phase II	975
Québec via Highgate	142
Maritimes	519
New York	354
Total Tie Benefits	1,990

- Modeled in the ICR calculations with the tie line availability assumptions shown below:

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

OP 4 Assumptions
- Minimum Operating Reserve Requirement(MW)

- Minimum Operating Reserve is the 10-Minute minimum Operating Reserve requirement for ISO Operations

- Modeled at 200 MW in the ICR calculation

Summary of all MW Modeled in the ICR Calculations (MW)

Type of Resource/OP 4	2019/20 FCA
Generating Resources	29,734.850
Intermittent Power Resources	919.119
Demand Resources	2,871.265
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(30.000)
OP 4 Voltage Reduction	442.000
Minimum Operating Reserve	(200.000)
Tie Benefits (with 975 MW of HQICCs)	1,990.000
Proxy Units	800.000
Total MW Modeled in ICR	**36,516.034**

Notes:

- Intermittent Power Resources have both the summer and winter capacity values modeled
- Import deratings reflect the value of the firm VJO contract
- OP 4 Voltage Reduction includes both Action 6 and Action 8 MW assumptions.
- Minimum Operating Reserve is the 10-Minute minimum Operating Reserve requirement for ISO Operations

Questions