Proposed Values for the Installed Capacity Requirement (ICR) & Related Values for the 2018/19 Forward Capacity Auction (FCA9)

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Objective of this Presentation

- Review the ICR development and FERC filing schedules

- Review the proposed ICR Values for calculating:
  - Installed Capacity Requirement (ICR),
  - Transmission Security Analysis (TSA),
  - Local Resource Adequacy Requirement (LRA),
  - Local Sourcing Requirement (LSR), and
  - Maximum Capacity Limit (MCL)**
  - Capacity requirement values for the System-Wide Capacity Demand Curve (Demand Curve)

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

**At the 8/28/2014 PSPC Meeting ISO-NE presented an analysis showing that Maine will not be a Capacity Zone for FCA9

ICR Review and FERC Filing Schedule

- ICR for 2018/19 Forward Capacity Auction (FCA9)
  - PSPC to review Capacity Zone determinations – **Jun 30, 2014**
  - PSPC final review of all assumptions – **Jul 24, 2014**
  - PSPC review of ISO recommendation of ICR Values – **Aug 28, 2014**
  - RC review/vote of ISO recommendation of ICR Values – **Sep 16, 2014**
  - PC review/vote of ISO recommendation of ICR Values – **Oct 3, 2014**
  - File with the FERC – by **Nov 5, 2014**
  - FCA9 begins – **Feb 2, 2015**

PROPOSED ICR VALUES FOR THE 2018/19 FCA

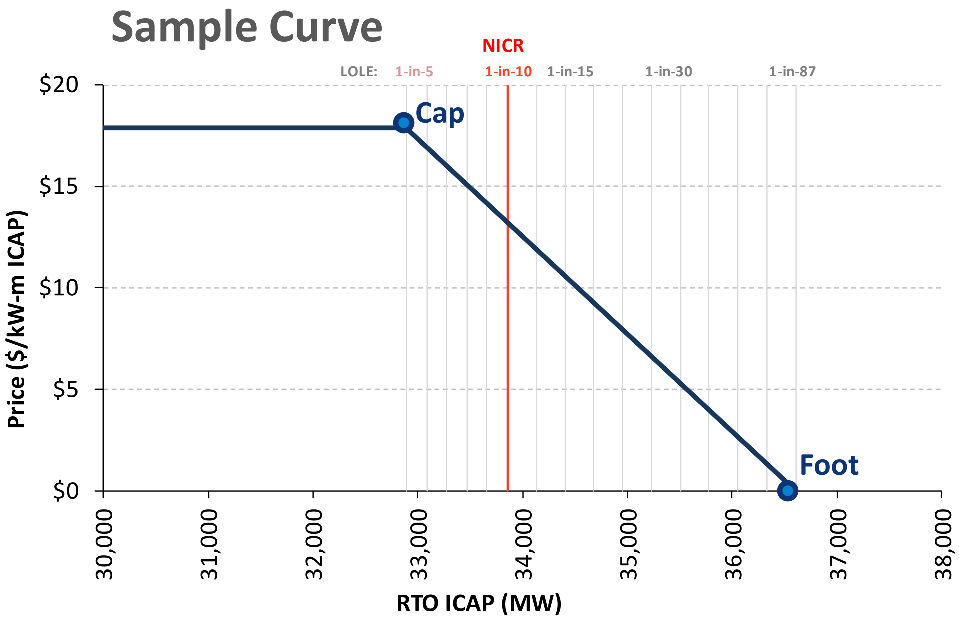
System-Wide Capacity Demand Curve

- Beginning in FCA9, ISO will calculate the quantity parameters (Net ICR) associated with the System-Wide Capacity Demand Curve

Curve Price-Quantity Parameters :

Cap [Net ICR at 1-in-5 LOLE, Max (1.6 x Net CONE, Gross CONE)]

Foot [Net ICR at 1-in-87 LOLE, $0]



Net ICR is ICR net of Hydro-Quebec Interconnection Capability Credits (HQICCs)

Net ICR is calculated at the 1-in-5 LOLE and 1-in-87 LOLE (the capacity requirement values for the System-Wide Capacity Demand Curve) in addition to Net ICR at the 1-in-10 LOLE

ISO Proposed ICR Values for the 2018/19 FCA (MW)

2018/19 FCA	New England	Connecticut	NEMA/ Boston	SEMA/RI
Peak Load (50/50)	30,005	7,725	6,350	5,910
Existing Capacity Resources*	32,842	9,239	3,868	6,984
Installed Capacity Requirement	35,142			
NET ICR (ICR Minus 953 MW HQICCs)	34,189			
Net ICR at 1-in-5 LOLE	33,132			
Net ICR at 1-in-87 LOLE	37,027			
Local Sourcing Requirements		7,331	3,572	7,479

*Existing Capacity Resources consists of capacity resources used in the ICR Values calculation and excludes HQICCs for New England.

*In addition to the Existing Capacity Resources shown, proxy units are required in the following amounts:

- ICR Calculation = 1,600 MW
- 1-in-5 LOLE Demand Curve capacity value calculation = 400 MW
- 1-in-87 LOLE Demand Curve capacity value calculation = 4,400 MW
- SEMA/RI LRA Calculation = 800 MW

Comparison of ICR Values (MW) - 2018/19 Vs 2017/18 FCA

	New England		Connecticut		NEMA/Boston		SEMA/RI	
	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA	2018/19 FCA	2017/18 FCA
Peak Load (50/50)	30,005	29,790	7,725	7,650	6,350	6,260	5,910	-
Existing Capacity Resources*	32,842	35,443	9,239	9,768	3,868	3,685	6,984	-
Installed Capacity Requirement	35,142	34,923						
NET ICR (ICR Minus HQICCs)	34,189	33,855						
NET ICR at 1-in-5 LOLE	33,132	-						
NET ICR at 1-in-87 LOLE	37,027	-						
Local Resource Adequacy Requirement			7,268	7,319	3,129	2,968	7,479	-
Transmission Security Requirement			7,331	7,273	3,572	3,428	7,116	-
Local Sourcing Requirement			7,331	7,319	3,572	3,428	7,479	-

*Existing Capacity Resources consists of capacity resources used in the ICR Values calculation and excludes HQICCs for New England.

*In addition to the Existing Capacity Resources shown for the 2018/19 FCA, proxy units are required in the following amounts:

- ICR Calculation = 1,600 MW
- 1-in-5 LOLE Demand Curve capacity value calculation = 400 MW
- 1-in-87 LOLE Demand Curve capacity value calculation = 4,400 MW
- SEMA/RI LRA Calculation = 800 MW

ICR Calculation Details

Total Capacity Breakdown	1-in-5	2018/19 FCA ICR	1-in-87
Generating Resources	29,829	29,829	29,829
Tie Benefits	1,970	1,970	1,970
Imports/Sales	(41)	(41)	(41)
Demand Resources	3,054	3,054	3,054
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
Proxy Unit Capacity	400	1,600	4,400
Total Capacity	**35,453**	**36,653**	**39,453**

Installed Capacity Requirement Calculation Details	1-in-5	2018/19 FCA ICR	1-in-87
Annual Peak	30,005	30,005	30,005
Total Capacity	35,453	36,653	39,453
Tie Benefits	1,970	1,970	1,970
HQICCs	953	953	953
OP4 - Action 6 & 8 (Voltage Reduction)	441	441	441
Minimum Reserve Requirement	(200)	(200)	(200)
ALCC	99	222	175
Installed Capacity Requirements	**34,085**	**35,142**	**37,980**
Net ICR	**33,132**	**34,189**	**37,027**
Reserve Margin with HQICCs	13.6%	17.1%	26.6%
Reserve Margin without HQICCs	10.4%	13.9%	23.4%

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

- 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.

Effect of Updated Assumptions on ICR

Assumption	2018/2019 FCA		2017/2018 FCA		Effect on ICR (MW)
Tie Benefits & Updated External Interface Outage Assumptions	346 MW New York		227 MW New York		-213
	523 MW Maritimes		492 MW Maritimes		
	953 MW Quebec (HQICCs)		1068 MW Quebec (HQICCs)		
	148 MW Quebec via Highgate		83 MW Quebec via Highgate		
Total	1,970 MW		1,870 MW		
	MW	Weighted Forced Outage	MW	Weighted Forced Outage	
Generation & IPR	29,699	6.5%	32,098	5.8%	178
Demand Resources	3,054	4.0%	3,416	5.8%	-85
Imports	89	0.0%	89	0.0%	0
	MW		MW		
Load Forecast	30,005		29,790		348
	MW	%	MW	%	
OP 4 5% VR	441	1.50%	432	1.50%	-9
	MW		MW		
ICR	35,142		34,923		219

- Methodology: Begin with model for the 2017/18 FCA ICR calculation. Change one assumption at a time and note the change in ICR caused by each change in assumption.

LRA - Connecticut

Local Resource Adequacy Requirement - Connecticut			
Connecticut Zone		**2018/19 FCA**	**2017/18 FCA**
$Resource_z$	[1]	9,239	9,768
$Proxy\ Units_z$	[2]	0	0
$Firm\ Load\ Adjustment_z$	[4]	1,825	2,282
FOR_z	[5]	0.074	0.068
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**7,268**	**7,319**
Rest of New England Zone			
Resource	[7]	23,603	25,675
Proxy Units	[8]	1,600	0
Firm Load Adjustment	[10] = -[4]	-1,825	-2,282
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,442	35,443

- All values in the table are in MW except the FORz
- Resources for Rest of New England excludes HQICCs

LRA – NEMA/Boston

Local Resource Adequacy Requirement - NEMA/BOSTON			
NEMA/BOSTON Zone		**2018/19 FCA**	**2017/18 FCA**
$Resource_z$	[1]	3,939	3,685
Proxy $Units_z$	[2]	0	0
Firm Load $Adjustment_z$	[4]	775	685
FOR_z	[5]	0.042	0.044
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**3,129**	**2,968**
Rest of New England Zone			
Resource	[7]	28,903	31,758
Proxy Units	[8]	1,600	0
Firm Load Adjustment	[10] = -[4]	-775	-685
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,442	35,443

- All values in the table are in MW except the FORz
- Resources for Rest of New England excludes HQICCs

LRA – SEMA/RI

Local Resource Adequacy Requirement - SEMA/RI			
NEMA/BOSTON Zone		**2018/19 FCA**	**2017/18 FCA**
Resource$_z$	[1]	6,984	-
Proxy Units$_z$	[2]	800	-
Firm Load Adjustment$_z$	[4]	278	-
FOR$_z$	[5]	0.090	-
LRA$_z$	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**7,479**	**-**
Rest of New England Zone			
Resource	[7]	25,857	-
Proxy Units	[8]	800	-
Firm Load Adjustment	[10] = -[4]	-278	-
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,442	-

- All values in the table are in MW except the FORz
- Resources for Rest of New England excludes HQICCs

MCL - Maine

Local RA Requirement - RestofNewEngland (for Maine MCL calculation)			
Rest of New England Zone		**2018/19 FCA**	**2017/18 FCA**
Resource_z	[1]	29,289	31,850
Proxy Units_z	[2]	1,600	0
$\text{Surplus Capacity Adjustment}_z$	[3]	250	1,570
$\text{Firm Load Adjustment}_z$	[4]	323	268
FOR_z	[5]	0.067	0.060
LRA_z	[6]=[1]+[2]-([3]/(1-[5]))-([4]/(1-[5]))	**30,275**	**29,894**
Maine Zone			
Resource	[7]	3,552	3,593
Proxy Units	[8]	0	0
Proxy Units Adjustment	[9]	-250	-1,570
Firm Load Adjustment	[10] = -[4]	-323	-268
Total System Resource	[11]=[1]+[2]-[3]-[4]+[7]+[8]-[9]-[10]	34,442	35,443

Maximum Capacity Limit - Maine			
Commitment Period		**2018/19 FCA**	**2017/18 FCA**
ICR for New England	[1]	34,189	33,855
$\text{LRA}_{\text{RestofNewEngland}}$	[2]	30,275	29,894
$\text{Maximum Capacity Limit}_Y$	[3]=[1]-[2]	**3,913**	**3,960**

- At the 8/28/2014 PSPC Meeting ISO-NE presented an analysis showing that Maine will not be a Capacity Zone for FCA9
- Maine-New Hampshire transmission transfer capability export limit used in the analysis is 1,900 MW
- All values in the table are in MW except the FORz
- Resources for Rest of New England excludes HQICCs

Assumptions for the 2018/19 FCA ICR Values Calculation

Modeling the New England Control Area

The New England ICR is calculated using the GE MARS model

- 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 LSR and MCL
- For FCA9, LSR is calculated for the Connecticut, NEMA/Boston Load Zones and SEMA/RI combined Load Zones. MCL will be calculated for the Maine Load Zone as a final step in the review of capacity zone determination for Maine, however, currently Maine is not expected to be export constrained

Assumptions for the ICR Calculations

- *Load Forecast*
  - Load Forecast distribution
- *Resource Data Based on Existing Qualified Capacity Resources for FCA9*
  - Generating Capacity Resources
  - Intermittent Power Capacity Resources
  - 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

Resources with Higher Summer than Winter Qualified Capacity

- Market Rule III.13.1.2.2.5.2. relating to requirements for an Existing Generating, Demand or Import Capacity Resource which has a Higher Summer Qualified Capacity than Winter Qualified Capacity must either: (i) offer its summer Qualified Capacity as part of an offer composed of separate resources, as discussed in Section III.13.1.5; or *(ii) have its FCA Qualified Capacity administratively set by the ISO to the lesser of its summer Qualified Capacity and winter Qualified Capacity*

- Resources in this situation can submit a composite offer in late September or they will have their Qualified Capacity decreased according the MR quoted above on October 20th. ISO-NE will not know the exact MWs of the reduced capacity in time to remove them from the model for the FCA9 ICR calculation.

- Table below summarizes the MWs of Qualified Capacity that may potentially be removed from the FCA9 Existing Qualified Capacity but will be included in the ICR model

Demand Resources		265.211
	Passive	207.536
	RTDR	47.507
	RTEG	10.168
Generators		53.452
	Non-Intermittent	53.452
	Intermittent	-
Imports		0
Total MWs		318.663

Load Forecast Data

- **Load forecast assumption from the 2014 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.

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
2018/19	26,860	30,005	30,005	24,805	19,090	20,840	23,195	23,195	22,080	20,575	18,460	21,355

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
2018/19	29,045	29,275	29,510	29,935	30,005	30,310	30,860	31,310	32,430	33,120

Resource Data – Generating Capacity Resources (MW)

Load Zone	Non-Intermittent Generation		Intermittent Generation		Total	
	Summer	Winter	Summer	Winter	Summer	Winter
MAINE	2,888.145	3,054.733	267.626	392.759	267.626	392.759
NEW HAMPSHIRE	4,070.494	4,273.306	167.628	222.733	167.628	222.733
VERMONT	255.102	294.141	79.038	121.579	79.038	121.579
CONNECTICUT	8,255.015	8,722.159	186.092	202.197	186.092	202.197
RHODE ISLAND	1,861.432	2,070.641	4.684	6.435	4.684	6.435
SOUTH EAST MASSACHUSETTS	4,471.042	4,934.675	75.866	77.907	75.866	77.907
WEST CENTRAL MASSACHUSETTS	3,880.929	4,128.907	59.642	93.077	59.642	93.077
NORTH EAST MASSACHUSETTS & BOSTON	3,235.563	3,642.555	70.231	72.023	70.231	72.023
Total New England	**28,917.722**	**31,121.117**	**910.807**	**1,188.710**	**29,828.529**	**32,309.827**

- Existing Qualified generating capacity resources for FCA9
- Intermittent resources have both summer and winter values modeled; non-Intermittent winter values provided for informational purpose
- A 30 MW derating is applied to Citizens Block Load (modeled as a generator) to reflect the value of the Vermont Joint Owners (VJO) contract

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 FCA9
- A 30 MW derating is applied to Citizens Block Load (modeled as a generator) to reflect the value of the VJO contract
- System-backed imports modeled as 100% available

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	176.925	164.463	0.000	0.000	207.892	225.787	11.802	9.299	396.619	399.549
NEW HAMPSHIRE	94.951	75.500	0.000	0.000	18.707	17.987	14.022	12.045	127.680	105.532
VERMONT	125.420	118.277	0.000	0.000	37.007	44.940	2.866	2.866	165.293	166.083
CONNECTICUT	80.728	58.930	324.316	279.113	254.510	227.087	138.338	137.824	797.892	702.954
RHODE ISLAND	172.704	166.857	0.000	0.000	57.595	54.064	33.540	29.149	263.839	250.070
SOUTH EAST MASSACHUSETTS	252.710	229.658	0.000	0.000	38.785	36.911	15.962	15.962	307.457	282.531
WEST CENTRAL MASSACHUSETTS	260.352	239.112	52.968	40.916	91.799	85.422	27.798	27.244	432.917	392.694
NORTH EAST MASSACHUSETTS & BOSTON	486.312	461.435	0.000	0.000	50.189	46.711	26.099	25.871	562.600	534.017
Total New England	1,650.102	1,514.232	377.284	320.029	756.484	738.909	270.427	260.260	3,054.297	2,833.430

- Existing Qualified Demand Resource capacity for FCA9
- Includes the Transmission and Distribution (T&D) Loss Adjustment (Gross-up) of 8%.

Sub-area Resource and Load Assumptions Used in LRA and MCL Calculations (MW)

Type of Resource	New England	Connecticut	NEMA/Boston	SEMA/RI
Generating Resources	28,787.722	8,255.015	3,235.563	6,332.474
Intermittent Power Resources	910.807	186.092	70.231	80.550
Passive Demand Resources	2,027.386	405.044	486.312	425.414
Active Demand Resources	1,026.911	392.848	76.288	145.882
Import Resources	88.800	-	-	-
Total MW Modeled	**32,841.626**	**9,238.999**	**3,868.394**	**6,984.320**
Load Forecast 50/50	**30,005**	**7,725**	**6,350**	**5,910**

- Resources for New England excludes HQICCs
- Load and generating resource assumptions are for the corresponding RSP area used as a proxy for the load zone. DR values are the load zone values.
- New England needs an additional 1,600 MW of proxy units to perform the ICR calculation
- SEMA/RI needs an additional 800 MW of proxy units to perform the LRA analysis

LRA & TSA Internal Transmission Transfer Capability Assumptions (MW)

- Transfer Limits – 2014 Regional System Plan (RSP) for 2018/19
  - Internal Transmission Transfer Capability
    - Connecticut Import
      - N-1 Limit: 2,950 MW
      - N-1-1 Limit: 1,750 MW
    - Boston Import
      - N-1 Limit: 4,850 MW
      - N-1-1 Limit: 4,175 MW
    - SEMA/RI Import
      - N-1 Limit: 786 MW
      - N-1-1 Limit: 473 MW

- Boston Import includes the impact of the Salem Harbor station retirement and the inclusion of the advanced NEMA/Boston upgrades. The effect of the addition of the Footprint generation project on the Boston import capability will be evaluated at a future date and will not be reflected in the LSR calculations for FCA9.
- The New England East-West Solution (NEEWS) is expected to be in-service by 12/2015 and has been certified and accepted by ISO-NE to be included in FCA9 analyses.

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 2009 – Dec 2013) 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 2009 – Dec 2013) 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	12,523	3.6	5.8
Fossil	6,254	14.9	5.2
Nuclear	4,024	3.1	3.9
Hydro (Includes Pumped Storage)	2,931	4.6	6.5
Combustion Turbine	2,908	9.5	2.3
Diesel	193	6.5	1.0
Miscellaneous	86	14.2	1.8
Total System	28,918	6.7	5.1

- 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	176.925	100%	-	-	207.892	99%	11.802	93%	396.619	99%
NEW HAMPSHIRE	94.951	100%	-	-	18.707	88%	14.022	99%	127.680	98%
VERMONT	125.420	100%	-	-	37.007	92%	2.866	82%	165.293	98%
CONNECTICUT	80.728	100%	324.316	100%	254.510	82%	138.338	85%	797.892	92%
RHODE ISLAND	172.704	100%	-	-	57.595	85%	33.540	90%	263.839	95%
SOUTH EAST MASSACHUSETTS	252.710	100%	-	-	38.785	84%	15.962	84%	307.457	97%
WEST CENTRAL MASSACHUSETTS	260.352	100%	52.968	100%	91.799	89%	27.798	89%	432.917	97%
NORTH EAST MASSACHUSETTS & BOSTON	486.312	100%	-	-	50.189	81%	26.099	89%	562.600	98%
Total New England	1,650.102	100%	377.284	100%	756.484	88%	270.427	88%	3,054.297	96%

- Uses historical DR performance from summer & winter 2010 – 2013. See presentation at: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/pwrsuppln_comm/mtrls/2014/jun302014/2014_dr_availability.pdf for more information.
- Modeled by zone and type of DR with outage factor calculated as 1- performance/100

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 2018 - Sep 2018	32,430	2,027	756	270	441
Oct 2018 - May 2019	23,940	1,834	739	260	317

- Use the 90-10 Peak Load Forecast minus all Passive DR & Active DR with RTEG limited to 600 MW, if necessary
- Multiplied by the 1.5% value used by ISO Operations in estimating relief obtained from OP4 voltage reduction

OP 4 Assumptions
- Tie Benefits (MW)

- The results of the 2018/19 Tie Benefits Study

Control Area	2018/19 FCA9	2017/18 FCA8
Québec via Phase II	953	1,068
Québec via Highgate	148	83
Maritimes	523	492
New York	346	227
Total Tie Benefits	1,970	1,870

- 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	2018/19 FCA
Generating Resources	28,917.722
Intermittent Power Resources	910.807
Demand Resources	3,054.297
Import Resources	88.800
Export Delist	(100.000)
Import Deratings	(30.000)
OP 4 Voltage Reduction	441.000
Minimum Operating Reserve	(200.000)
Tie Benefits (Includes 953 MW of HQICCs)	1,970.000
Proxy Units	1,600.000
Total MW Modeled in ICR	**36,652.626**

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