To: AESC 2015 Update client group

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Subject AESC 2015 Update results and assumptions

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This memo presents the results from the AESC 2015 Update and the underlying assumptions.

Background to AESC 2015 Update

In August 2015, the efficiency program administrators ("PAs) in Maine, New Hampshire, Rhode Island and Vermont retained the Tabors Caramanis Rudkevich (TCR) team who prepared AESC 2015 to prepare a limited update of that study, i.e., then AESC 2015 Update.

The AESC 2015 Update provides limited updates of Appendix B (Avoided Electricity Costs), Appendix C (Avoided Natural Gas Costs), and Appendix D (Avoided Costs of Petroleum and Other Fuels). The updates are limited as follows:

- Updates of only six input assumptions - crude oil / fuel oil prices, natural gas commodity costs, electric generating capacity retirements, additions and Forward Capacity Market (FCM) results, and a new ISO-NE zone;
- calculations based on the methodologies and models the TCR team used to prepare AESC 2015;
- no updates of renewable energy compliance costs or DRIPE;
- update results reported for Maine, New Hampshire, Rhode Island and Vermont in constant 2017$, starting in 2017.

The memo is organized as follows:

1 Updated Input Assumptions

2 Avoided Electricity Costs (AESC 2015 Update Appendix B)

3 *A*voided Natural Gas Costs by End Use (AESC 2015 Update Appendix C)

4 Avoided fuel costs to retail customers (AESC 2015 Update Appendix D)

Attachments

1. updated fuel price assumptions - crude oil / fuel oil and natural gas
2. updated electric model input assumptions
3. updated financial parameters

Appendices

B. Avoided Electricity Costs
C. Avoided Natural Gas Costs
D. Avoided Costs of Petroleum and Other Fuels

1 Updated Input Assumptions

This section summarizes the updated input assumptions. Attachments 1, 2 and 3 provide the details of the updated input assumptions. Attachment 1 provides updated fuel price assumptions for crude oil / fuel oil and natural gas. These assumptions cover fuels for electric generation. Attachment 2 provides the updated electric model input assumptions. Attachment 3 provides the updated financial parameters used in the AESC 2015 Update.

The key differences between the AESC 2015 Update fuel price assumptions and those used in AESC 2015 are as follows:

- a slightly lower forecast for crude oil prices. For example, on a 15 year levelized basis, for 2017 – 2031, the AESC 2015 Updated projection of West Texas Intermediate (WTI) crude prices is 0.9% less than the corresponding 15 year levelized AESC 2015 projection for 2016 – 2030.
- a lower forecast for Henry Hub prices. For example, the 15 year levelized cost is approximately 15% less than the AESC 2015 Base case.
- a higher forecast of basis between Henry Hub and New England. For example, the 15 year levelized basis projection that is about 18% higher than the AESC 2015 Base Case. This higher forecast reflects the updated assumption that less new pipeline capacity will be added to serve New England than assumed in AESC 2015 (i.e. approximately 550 MMcf/day versus 1,000 MMcf/day).
- a lower forecast for natural gas spot prices in New England. For example, on a 15 year levelized basis, the AESC 2015 Update projection of the avoided cost of spot gas in New England is about 11% less than the AESC 2015 Base case. This projection reflects the combined impact of a lower avoided cost of gas at the Henry Hub and a higher basis projection.

The lower forecast for natural gas spot prices in New England affects the projection of avoided electricity costs but not the projection of avoided natural gas costs to end use customers. The lower forecast for natural gas spot prices in New England affects the projection of the projection of avoided electric energy costs because it affects the projected costs to gas-fired power plants. The lower forecast for natural gas spot prices in New England does not affect avoided gas costs to residential and commercial end users, because those end users are supplied by gas utilities who hold adequate firm pipeline capacity for which they pay cost base rates. Thus, the AESC 2015 Update assumptions regarding pipeline expansions to New England affect the projection of avoided electricity costs but not the projection of avoided natural gas costs to end use customers.

The key differences between the AESC 2015 Update electric model input assumptions and those used in AESC 2015 are as follows:

- a somewhat lower forecast for peak demand and annual energy, in the order of 5 %. This is due to the combined effect of a lower ISO-NE gross load forecast and to a higher quantity of passive demand reductions (PDR).
- ISO-NE approved retirements of Pilgrim nuclear plant in 2019;
- ISO-NE approved additions of 2,800 MW of gas-fired combined cycle (CC) units, 333 MW of oil fired CC, 408 MW of gas turbines, 339 MW of wind units and 378 MW of renewable capacity from various sources. The scheduled online dates of these additions range between 2016 and 2019;

- projected additions of 9,450 GWH of imported hydro and 1,600 MW of offshore wind between 2021 and 2023 to comply with Massachusetts clean power procurement legislation of July 2016.

The key differences between the AESC 2015 Update financial input assumptions and those used in AESC 2015 are the inflation rate of 2.00%, versus 1.88% in AESC 2015, and the long term real discount rate of 1.43% versus 2.43% in AESC 2015. (As in prior AESC studies, the AESC 2015 Update uses that discount rate to calculate illustrative levelized costs for 10 years (2017-2026), 15 years (2017 – 2031) and 30 years (2017-2046). The AESC 2015 Update provides illustrative comparisons of 15 year levelized costs with the corresponding AESC 2015 results. The impact of the difference in discount rates between the two studies for 15 year levelized costs is minimal, for example about 0.5% of the differences between avoided retail electric energy cost results relative to the total differences which range from 65 to 16%.)

2 Avoided Electricity Costs (AESC 2015 Update Appendix B)

The AESC 2015 Update Appendix B results reflect updated assumptions for fuel costs (i.e., natural gas, distillate and residual), forecast electric load, electric generating capacity retirements, additions and Forward Capacity Market (FCM) results and the new ISO-NE zone. Attachment 2 describes those updated input assumptions. Other than those updated inputs, AESC 2015 Update uses the same inputs and methodologies as AESC 2015.

The AESC 2015 Update developed updated avoided costs of wholesale electric capacity and wholesale electric energy.

- The AESC 2015 Update projection of avoided wholesale electric capacity costs are lower than the AESC 2015 projections. For example, 15 year levelized power year (June – May) costs are approximately 15% lower. This change is primarily due to assumed procurement of nearly 1500 MW of incremental firm supply of hydro power from Canada, 1600 MW of offshore wind and RPS driven renewable additions. These additions create a multi-year capacity surplus in excess of New England Installed Capacity Requirements.
- The AESC 2015 Update projection of avoided wholesale electric energy are generally lower than those in AESC 2015. For example, 15 year levelized costs in 2017-2031 period for the New England Hub (using WCMA Zone as a proxy for the hub) are approximately 12% lower. The levelized annual wholesale electric energy costs are lower primarily due to lower projections of natural gas prices to gas-fired power plants in New England. The other driving factor are the significant additions of low energy cost supplies such as hydro based imports from Canada, off-shore wind and other renewables added to meet RPS requirements.

The AESC 2015 Update did not develop updated avoided costs of renewable portfolio compliance costs, non-embedded CO_2 costs or electricity DRIPE. The Appendix B values reported for those components are the ASEC 2015 Appendix B values, expressed in 2017$.

A. Avoided Wholesale Capacity Costs

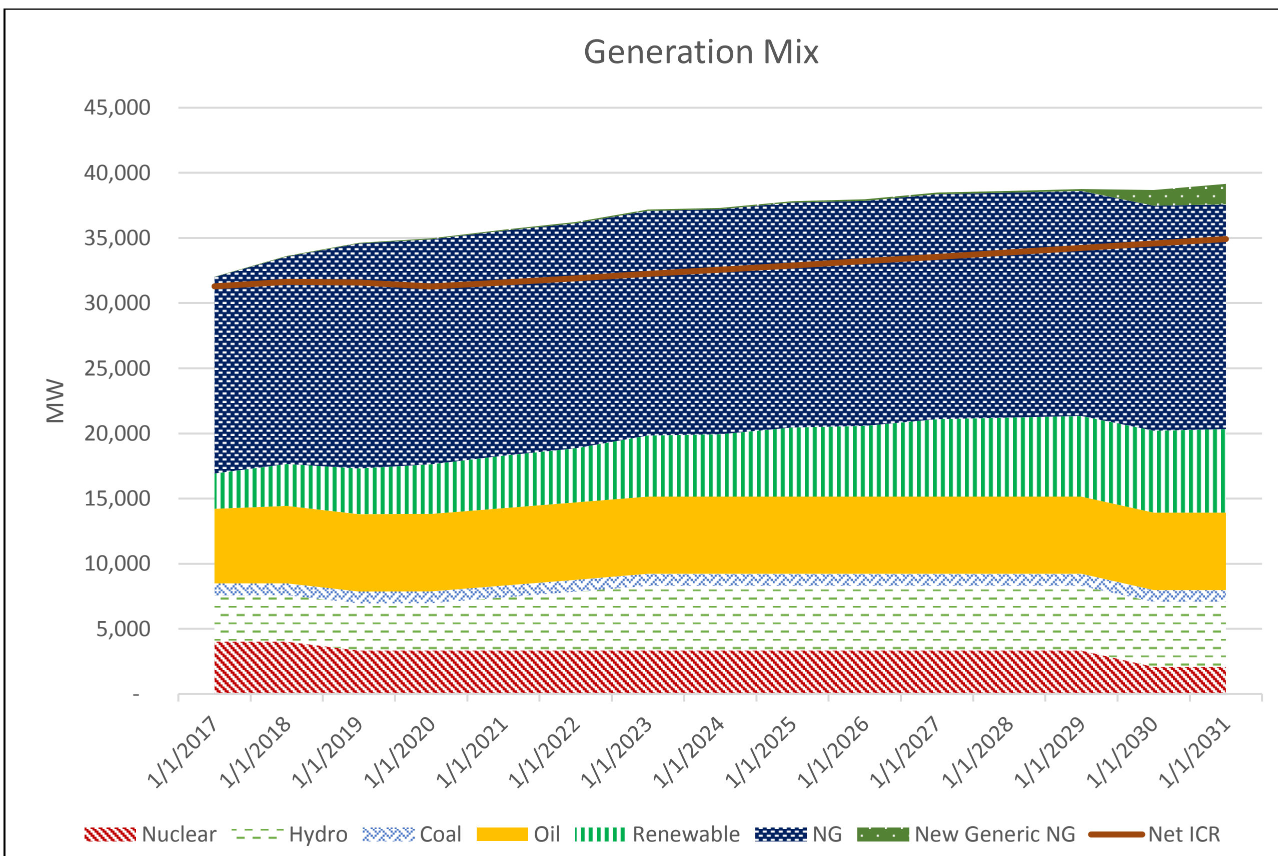
The major drivers of the avoided wholesale capacity price are installed capacity requirements (ICR, the capacity resources available to meet those requirements and the ISO-NE rules governing the Forward Capacity Auctions (FCA) for capacity to meet those requirements. The ICR is a function of projected system peak demand and reserve margin. The AESC 2015 Update projects net ICR requirements, which is ICR minus the existing import capacity from Hydro Quebec. The ISO-NE FCA rules specify which resources are allowed to bid in the auction, how the resources' capacity values are computed, and what range of prices each resource category is allowed to bid.

The AESC 2015 Update determined the projected load-resource balance based on projections of load growth, retirements of existing capacity, capacity acquired through FCAs, capacity to comply with RPS and clean energy requirements, imports and exports. As indicated in

Figure 1, the AESC 2015 Update projects the following capacity additions:

- 4,200 MW of new generating units that have cleared in FCA's conducted to date which are scheduled to come online in the 2017/18, 2018/19 and 2019/20 power years (The ISO-NE power year is June through May).
- nearly 1,500 MW of Canadian imports, 1,600 MW of offshore wind and annual RPS additions driven by clean energy and renewable policy requirements.
- three generic CCGTs (1050 MW in total) and 350 MW of generic GT capacity in 2030 driven by the scheduled retirement of the Seabrook nuclear unit.

Figure 1. AESC 2015 Update Capacity Requirements vs. Resources (MW)



The AESC 2015 Update projection of avoided wholesale electric capacity costs is lower than the AESC 2015 projections. For example, 15 year levelized power year costs are approximately 15% lower, calendar year costs are 12% lower. This change is primarily due to assumed procurement of nearly 1500 MW of incremental firm supply of hydro power from Canada, 1600 MW of offshore wind and renewable additions which create a multi-year capacity surplus in excess of New England Installed Capacity Requirements. Table 1 provides the AESC 2015 Update avoided wholesale capacity costs by power year and calendar year respectively.

Table 1 AESC 2015 Update Avoided Wholesale Capacity Costs by Power Year and Calendar Year

Power Year (June - May)				Calendar Year			
FCA and Power Year	AESC 2015 (1)		AESC 2015 Update	Year	AESC 2015 (2)		AESC 2015 Update (2)
	2015$ / kW-month	2017$ / kW-month	2017$ / kW-month		2015$ / kW-year	2017$ / kW-year	2017$ / kW-year
FCA 6, 2015/16	*$ 3.38*	*$ 3.48*		2015			
FCA 7, 2016/17	*$ 3.15*	*$ 3.24*	*$ 3.21*	2016	*$ 38.16*	*$ 39.30*	*$ -*
FCA 8, 2017/18	*$ 14.19*	*$ 14.62*	*$ 15.00*	2017	*$ 114.53*	*$ 117.96*	*$ 121.03*
FCA 9, 2018/19	$ 12.96	$ 13.35	*$ 9.38*	2018	$ 132.93	$ 136.91	*$ 140.65*
FCA 10, 2019/20	$ 11.29	$ 11.63	*$ 6.78*	2019	$ 123.29	$ 126.99	*$ 94.33*
2020/21	$ 11.33	$ 11.67	$ 8.94	2020	$ 135.75	$ 139.83	$ 96.49
2021/22	$ 11.71	$ 12.06	$ 8.34	2021	$ 138.60	$ 142.76	$ 103.09
2022/23	$ 11.62	$ 11.97	$ 7.92	2022	$ 139.90	$ 144.10	$ 97.14
2023/24	$ 11.37	$ 11.71	$ 7.38	2023	$ 137.73	$ 141.86	$ 91.28
2024/25	$ 11.96	$ 12.32	$ 8.31	2024	$ 140.57	$ 144.79	$ 95.06
2025/26	$ 11.96	$ 12.32	$ 9.03	2025	$ 143.50	$ 147.80	$ 104.77
2026/27	$ 12.04	$ 12.40	$ 9.93	2026	$ 144.08	$ 148.41	$ 114.70
2027/28	$ 11.79	$ 12.14	$ 10.66	2027	$ 142.75	$ 147.03	$ 124.25
2028/29	$ 12.46	$ 12.83	$ 11.54	2028	$ 146.18	$ 150.56	$ 134.04
2029/30	$ 12.79	$ 13.18	$ 12.41	2029	$ 151.86	$ 156.42	$ 144.55
2030/31			$ 13.81	2030	$ 153.53	$ 158.14	$ 158.75
			$ 13.71	2031			$ 165.07
15 yr Levelized Values							
15/16 to 29/30		$11.08		2016 - 2030		$134.14	
16/17 to 30/31			$9.43	2017 - 2031			$118.16
AESC 2015 Update vs AESC 2015			-15%				-12%
Notes							
Inflator 2015$ to 2017$	1.03						
Discount Rates							
AESC 2015	2.43%						
AESC 2015 Update	1.43%						

Values reported in shaded italics are actual FCA results in nominal $ which AESC 2015 converted to 2015$ and AESC 2015 Update converts to 2017$. Minimal differences in 16/17 and 17/18 due to differnces in conversion factors between AESC and AESC 20915 Update.

Source 1	Exhibit 5-32, AESC 2015, corrected levelization value
Source 2	Appendix B, AESC 2015 and AESC 2015 Update

B. Avoided Wholesale Energy Costs

The AESC 2015 Update projects generation from natural gas to be the dominant source of electric energy over the study period. Renewable generation is projected to increase over time in compliance with RPS requirements. Generation from nuclear is projected to decline in 2019 due to Pilgrim retirement, remain flat until year 2029 and then decline again based on the assumption of Seabrook retiring in March 2030. Coal generation is projected to decline substantially by 2020 as existing coal units retire. Figure 2 presents the projected mix of generation underlying our projection of wholesale electric energy prices.

Figure 2. AESC 2015 Update Generation Mix (GWh)

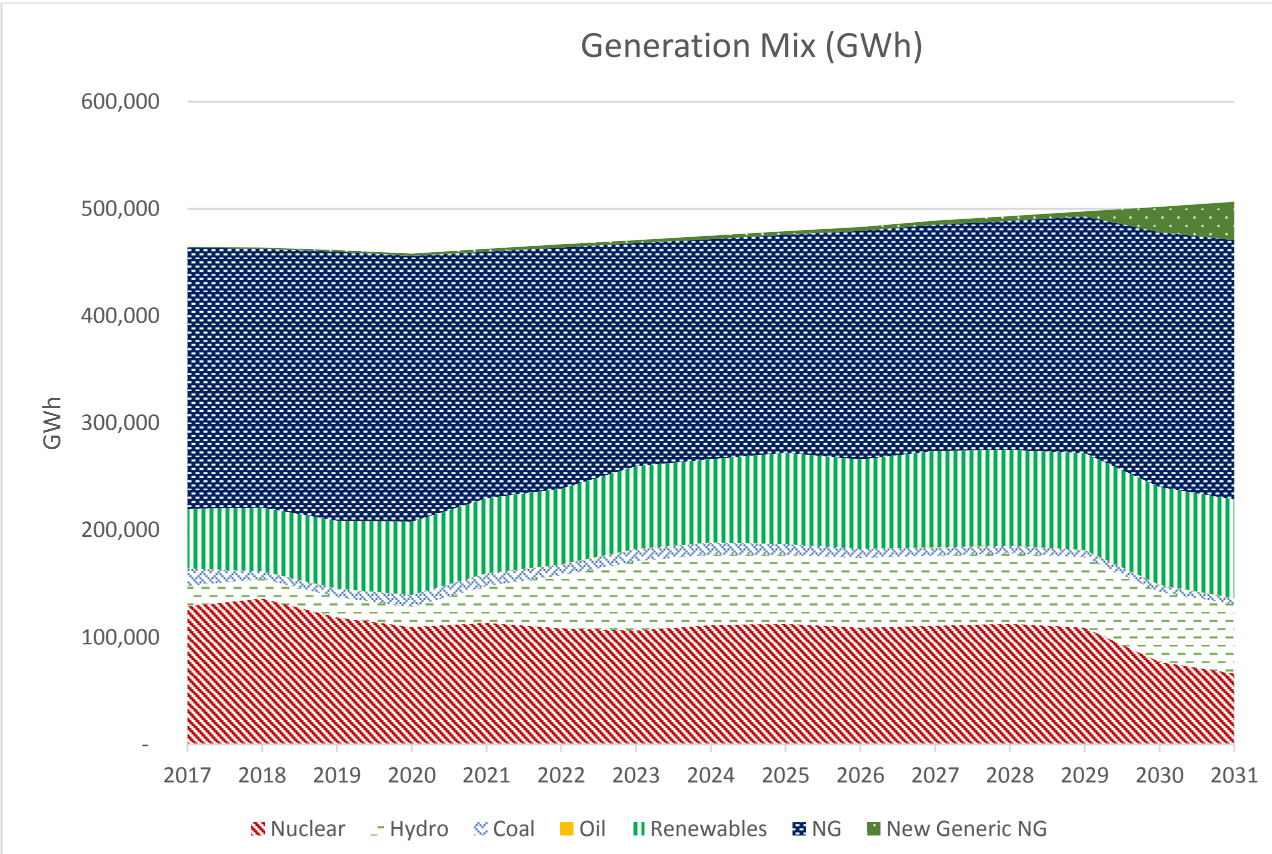


Table 2 presents AESC 2015 Update statewide wholesale electric energy prices for ME, NH, RI and VT on a 15 year levelized basis (2017-2031). It also provides the corresponding levelized wholesale energy prices for 2016 to 2030 from AESC 2015, and the changes relative to those values. The AESC 2015 Update values are 6% to 16 % lower than the corresponding AESC 2015 values, depending on time period and state. These reductions are primarily due to the lower projection of gas prices to gas-fired power plants in New England. The AESC 2015 Update 15 year levelized city-gate prices of natural gas are 11% lower than AESC 2015 Projection. The other driving factor are the significant additions of low energy cost supplies such as hydro based imports from Canada, off-shore wind and other renewables added to meet RPS requirements.

Table 2. AESC 2015 Update vs. AESC 2015 Wholesale Electric energy Prices by period. (2017$/kWh)

Avoided Wholesale Electric Energy Costs, AESC 2015 Update versus AESC 2015 (15 year levelized 2017$)				
	Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
AESC 2015 Update (2017 - 2031) [1]	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
Maine (ME)	0.0591	0.0513	0.0508	0.0390
New Hampshire (NH)	0.0591	0.0513	0.0509	0.0390
Rhode Island (RI)	0.0592	0.0513	0.0509	0.0391
Vermont (VT)	0.0591	0.0513	0.0509	0.0390
AESC 2015 (2016 - 2030) [2]	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
Maine (ME)	0.063	0.057	0.058	0.046
New Hampshire (NH)	0.064	0.059	0.059	0.046
Rhode Island (RI)	0.064	0.059	0.059	0.046
Vermont (VT)	0.064	0.059	0.059	0.047
Change from AESC 2015 ($/kWh)	**$/kWh**	**$/kWh**	**$/kWh**	**$/kWh**
Maine (ME)	(0.004)	(0.006)	(0.007)	(0.006)
New Hampshire (NH)	(0.004)	(0.007)	(0.008)	(0.007)
Rhode Island (RI)	(0.005)	(0.007)	(0.008)	(0.007)
Vermont (VT)	(0.005)	(0.007)	(0.008)	(0.008)
Change from AESC 2015 (%)	**%**	**%**	**%**	**%**
Maine (ME)	-6%	-11%	-13%	-14%
New Hampshire (NH)	-7%	-12%	-14%	-16%
Rhode Island (RI)	-7%	-12%	-14%	-15%
Vermont (VT)	-7%	-12%	-14%	-16%

SOURCES
1 AESC 2015 Update, Appendix B, columns v to y
2 AESC 2015 Appendix B, columns v to y, values in 2015$ inflated by 1.030 to 2017$

C. Avoided Retail Electric Energy Costs

Avoided retail electricity costs at the customer meter consist of the wholesale electric energy prices, as reported in Table 2, plus avoided renewable energy compliance costs and the wholesale risk premium.

Table 3 presents the AESC 2015 Update statewide 15-year levelized avoided retail electric energy costs for ME, NH, RI and VT. This table also provides the corresponding levelized retail energy prices for 2016 to 2030 from AESC 2015. This table corresponds to AESC 2015 Exhibit 1-6.

Table 3. Avoided Retail Electric Energy Costs, AESC 2015 update vs. AESC 2015 (15-year levelized, 2017$)

Avoided Retail Electric Energy Costs, AESC 2015 Update versus AESC 2015 (15 year levelized 2017$)					
		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
	AESC 2015 Update (2017 - 2031)	$/kWh	$/kWh	$/kWh	$/kWh
3	Maine (ME)	0.0650	0.0565	0.0560	0.0431
4	New Hampshire (NH)	0.0736	0.0651	0.0646	0.0517
5	Rhode Island (RI)	0.0703	0.0618	0.0613	0.0484
6	Vermont (VT)	0.0644	0.0559	0.0555	0.0425
	AESC 2015 (2016 - 2030)	$/kWh	$/kWh	$/kWh	$/kWh
3	Maine (ME)	0.069	0.063	0.064	0.050
4	New Hampshire (NH)	0.078	0.073	0.073	0.059
5	Rhode Island (RI)	0.075	0.070	0.070	0.056
6	Vermont (VT)	0.069	0.064	0.065	0.051

SOURCES
AESC 2015 Update, Appendix B, columns a to d
AESC 2015 Appendix B, columns a to d, values in 2015$ inflated by 1.030 to 2017$

Table 4 presents the changes between the AESC 2015 Update statewide 15-year levelized avoided retail electric energy costs and the corresponding AESC 2015 values for 2016 to 2030. This table corresponds to AESC 2015 Exhibit 1-7

Table 4. Avoided Retail Electric Energy Costs, AESC 2015 update vs. AESC 2015 (15-year levelized, Expressed as 2017$ and percentage values)

Avoided Retail Electric Energy Costs, AESC 2015 Update versus AESC 2015 (15 year levelized 2017$) AESC 2015 Update change from AESC 2015					
		Winter On Peak Energy	Winter Off-Peak Energy	Summer On Peak Energy	Summer Off-Peak Energy
	Change from AESC 2015 ($/kWh)	$/kWh	$/kWh	$/kWh	$/kWh
3	Maine (ME)	(0.004)	(0.007)	(0.008)	(0.007)
4	New Hampshire (NH)	(0.005)	(0.008)	(0.009)	(0.008)
5	Rhode Island (RI)	(0.005)	(0.008)	(0.009)	(0.008)
6	Vermont (VT)	(0.005)	(0.008)	(0.009)	(0.008)
	Change from AESC 2015 (%)	%	%	%	%
3	Maine (ME)	-5.7%	-10.7%	-12.7%	-14.2%
4	New Hampshire (NH)	-6.1%	-10.7%	-11.9%	-13.0%
5	Rhode Island (RI)	-6.7%	-11.2%	-12.7%	-13.8%
6	Vermont (VT)	-7.2%	-12.4%	-14.1%	-16.1%

D. Total Avoided Electricity Costs

Total avoided electricity costs consist of avoided retail capacity costs, avoided retail energy costs, avoided REC costs, and depending on the state avoided non-embedded carbon costs and DRIPE.

Table 5 illustrates the relative magnitude of each component of a 15 year levelized (2017 – 2031) avoided electricity cost for an efficiency measure with a 55-percent load factor implemented in the West

Central Massachusetts zone (“WCMA”) during the Summer On-Peak costing period. This table corresponds to AESC 2015 Exhibit 1-2.

- For this costing location and period, the AESC 2015 Update is projecting total avoided costs from direct reductions in energy and capacity of 9.15 cents per kWh. This amount is 1.3 cents, or approximately 13 percent, lower than the corresponding AESC 2015 total.
- The total of all components is 14.87. This total is 1.3 cents, or 8 percent, lower than the corresponding AESC 2015 total for 2016 – 2030.

Table 5. Illustration of Avoided Electricity Cost Components, AESC 2015 Update vs. AESC 2015 (WCMA Zone, Summer On-Peak, 15-Year Levelized Results, 2017$)

Illustration of Avoided Electricity Cost Components, AESC 2015 Update vs. AESC 2015[1]
Summer On-Peak, 15 Year Levelized Results, 2017$ - WCMA Zone

	AESC 2015 in 2015$	AESC 2015 in 2017$	AESC 2015 Update	AESC 2015 Update Relative to AESC 2015	
	cents/kWh	cents/kWh	cents/kWh	cents/kWh	% Difference
Avoided Retail Capacity Costs [2,3,4]	2.91	3.00	2.64	-0.35	-12%
Avoided Retail Energy Cost [5, 6, 7]	6.29	6.48	5.52	-0.96	-15%
Avoided Renewable Energy Credit [5, 6]	0.96	0.99	0.99	0.00	0%
Capacity and Energy Subtotal	**10.15**	**10.46**	**9.15**	**-1.31**	**-13%**
CO_2 Non-Embedded	4.48	4.61	4.61	0.00	0%
Capacity DRIPE	0.00	0.00	0.00	0.00	-
Intrastate Energy, Own Fuel and Cross-Fuel DRIPE	1.08	1.11	1.11	0.00	0%
DRIPE Subtotal	**1.08**	**1.11**	**1.11**	0.00	0%
Total	**15.71**	**16.19**	**14.87**	-1.31	-8%

Notes

1. AESC 2015 values for 2016-2030 from Exhibit 1-2 of AESC 2015, inflated to 2017$ at		**1.03**
2. Assumes load factor of		**55%**
3. Avoided Cost of Capacity purchases ($/kW-year)		**$ 140.10**
from Appendix B column f	AESC 2015 Update (2017)	**$ 121.00**
4. Adjusted for 8% distribution losses and 17% reserve margin		
5. Retail Adjustment = Avoided Wholesale Cost * (1 + risk premium)		
6. Risk premium (Appendix B)		**9%**
7. Avoided Wholesale Energy Cost (2017$/MWh) from Appendix B column x		**$ 50.62**

3 *A*voided Natural Gas Costs by End Use (AESC 2015 Update Appendix C)

The avoided cost of gas at a retail customer’s meter has two components: (1) the avoided cost of gas delivered to the local distribution company (“LDC”), and (2) the avoided cost of delivering gas on the LDC system (the “retail margin”). Attachment 1 describes the inputs to the AESC 2015 Update projection. Otherwise, the update uses the same AESC 2015 inputs and methodologies. Appendix C presents these avoided gas costs without an avoided retail margin for RI, ME, NH, and VT. As the ability to avoid the retail margin varies by LDC, the Appendix also provides these assuming some avoided retail margin for RI, ME and NH.

TCR prepared a limited update of Appendix C starting in 2017, expressed in constant 2017$, per the scope of work in our August 2 proposal. The Appendix C update reflects the AESC 2015 Update projection of natural gas commodity costs at the Henry Hub. On a 15 year levelized basis, the AESC 2015 Updated projection of Henry Hub prices is 15% less than the corresponding 15 year levelized AESC 2015 projection. Attachment 2 describes the inputs to the AESC 2015 Update projection. Otherwise, the update uses the same AESC 2015 inputs and methodologies

Table 6 presents the AESC 2015 Update 15 year levelized avoided costs, for 2017 – 2031, without an avoided retail margin for RI, ME and NH. Table 7 provides these for Vermont. The Tables also compare the AESC 2015 Update results to the corresponding values from AESC 2015. These two tables correspond to AESC 2015 Exhibit 1-9.

- The results for RI, ME and NH are 8% to 14% lower than the AESC 2015 estimates. These differences are due to the lower projection of Henry Hub prices, which is 15% lower on a calendar year basis than the AESC 2015 projection. The % differences vary by sector and end use due to differences in load shapes and differences in monthly prices.
- The estimates for VT design day and peak day costs are similar to the AESC 2015 values because the Henry Hub price has only a small impact on those two costs. The costs for the remaining winter and summer/shoulder periods are 10 to 13% lower.

Table 6. Avoided costs of gas by end-use, Southern and Northern New England, assuming no avoidable margin

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2015 AND AESC 2015 Update
ASSUMING NO AVOIDABLE RETAIL MARGIN
2017$/MMBtu except where indicated as 2015$/MMBtu

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			All Retail End Uses
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2015 (2015$)	6.00	6.53	6.70	6.56	6.20	6.54	6.39	6.48
AESC 2015 (b)	6.18	6.72	6.90	6.76	6.39	6.73	6.58	6.68
AESC 2015 Update	5.34	5.88	6.06	5.92	5.55	5.89	5.74	5.84
2015 to 2015 Update change	-14%	-12%	-12%	-12%	-13%	-12%	-13%	-13%
Northern New England (ME, NH)								
AESC 2015 (2015$)	6.00	7.69	8.25	7.80	6.63	7.71	7.24	7.54
AESC 2015 (b)	6.18	7.92	8.50	8.04	6.83	7.95	7.46	7.77
AESC 2015 Update	5.33	7.20	7.82	7.32	6.03	7.23	6.70	7.04
2015 to 2015 Update change	-14%	-9%	-8%	-9%	-12%	-9%	-10%	-9%

Factor to convert 2015$ to 2017$ 1.0300

Note: AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.
AESC 2015 Update levelized costs for 15 years 2017 - 2031 at a discount rate of 1.43%.

Table 7 Avoided costs of gas to end-users, Vermont

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
AESC 2015 Update versus AESC 2015
ASSUMING NO AVOIDABLE RETAIL MARGIN
2017$/MMBtu except where indicated as 2015$/MMBtu

Vermont	Design day	Peak Days	Remaining winter	Shoulder / summer
AESC 2015 (2015$)	523.08	21.83	7.51	6.19
AESC 2015 (b)	538.77	22.48	7.73	6.38
AESC 2015 Update	537.97	23.40	6.94	5.58
2015 to 2015 Update change	-0.1%	4%	-10%	-13%

Factor to convert 2013$ to 2015$ 1.0300

Note: AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.
AESC 2015 Update levelized costs for 15 years 2017 - 2031 at a discount rate of 1.43%

Table 8 presents the AESC 2015 Update avoided cost estimates with an avoided retail margin. The results for RI, ME and NH are 7% to 13% lower than the AESC 2015 estimates. These differences are again due to the lower projection of Henry Hub prices, which is 15% lower on a calendar year basis than the AESC 2015 projection. The % differences vary by sector and end use due to differences in load shapes and differences in monthly prices, as well as differences in avoided retail margin. This table corresponds to AESC 2015 Exhibit 1-10.

Table 8 Avoided Gas Cost by end-use, Southern and Northern New England, Some Avoidable Margin

COMPARISON OF LEVELIZED AVOIDED COSTS OF GAS DELIVERED TO RETAIL CUSTOMERS
BY END USE: AESC 2015 AND AESC 2015 Update
ASSUMING SOME AVOIDABLE RETAIL MARGIN
2017$/MMBtu except where indicated as 2015$/MMBtu

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			All Retail End Uses
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England (CT, MA, RI)								
AESC 2015 (2015$)	6.62	7.89	8.32	8.13	6.81	7.68	7.37	7.76
AESC 2015 (b)	6.82	8.13	8.57	8.38	7.02	7.91	7.59	7.99
AESC 2015 Update	5.96	7.25	7.68	7.49	6.16	7.04	6.72	7.12
2015 to 2015 Update change	-13%	-11%	-10%	-11%	-12%	-11%	-11%	-11%
Northern New England (ME, NH)								
AESC 2015 (2015$)	6.52	8.86	9.64	9.15	7.11	8.61	8.01	8.35
AESC 2015 (b)	6.72	9.12	9.92	9.42	7.32	8.87	8.25	8.60
AESC 2015 Update	5.86	8.37	9.20	8.67	6.51	8.12	7.47	7.84
2015 to 2015 Update change	-13%	-8%	-7%	-8%	-11%	-8%	-9%	-9%

Factor to convert 2015$ to 2017$ 1.0300

Note: AESC 2015 levelized costs for 15 years 2016 - 2030 at a discount rate of 2.43%.
AESC 2015 Update levelized costs for 15 years 2017 - 2031 at a discount rate of 1.43%.

4 Avoided fuel costs to retail customers (AESC 2015 Update Appendix D)

The AESC 2015 Update Appendix D reflects the updated projection of crude oil costs. On a 15 year levelized basis, for 2017 – 2031, the AESC 2015 Updated projection of West Texas Intermediate (WTI) crude prices is 0.8% less than the corresponding 15 year levelized AESC 2015 projection for 2016 – 2030. Attachment 1 describes the inputs to the AESC 2015 Update projection. Otherwise, the update uses the same AESC 2015 inputs and methodologies

Table 9 presents the AESC 2015 Update 15 year levelized avoided costs, for 2017 – 2031, for several Residential Sector fuels and for Commercial sector distillate and residual. The Table also compares the AESC 2015 Update results to the corresponding values from AESC 2015. The results are 1.9% to 2.8% lower than the AESC 2015 estimates. These differences are due to the 0.8% lower projection of WTI prices, and the impact of differences between the AESC 2015 Update discount rate of 1.43% and the AESC 2015 discount rate of 2.43% on fuel cost margins relative to crude oil. This table corresponds to AESC 2015 Exhibit 1-12.

Table 9. Avoided costs of fuels to residential and commercial customers

Avoided Costs of Fuels, (15 year Levelized, 2017$) - AESC 2015 Update vs AESC 2015									
Sector	**AESC 2015 Update Forecast WTI**		**Residential ($/MMBtu)**					**Commercial ($/MMBtu)**	
Fuel	**$/BBl**	**$/MMBtu**	**No. 2 Distillate**	**Propane**	**Kerosene**	**Cord Wood**	**Wood Pellets**	**No. 2 Distillate**	**No. 6 Residual (low sulfur)**
AESC 2015 Update, Levelized Values, 2017-2031	$80.29	$13.84	$20.22	$18.86	$22.05	N/A	N/A	$18.93	$16.64
AESC 2015 Levelized Values, 2016-2030 (1)	$ 80.90	$ 13.96	$ 20.61	$ 19.39	$ 22.48	$ 7.30	$ 8.30	$ 19.26	$ 16.96
AESC 2015 Update vs AESC 2015, % higher (lower)	-0.8%	-0.8%	-1.9%	-2.8%	-1.9%	$0.00	$0.00	-1.7%	-1.9%
Source 1	AESC 2015, Exhibits D-1 and D-2, inflated to 2017$ by 1.03								

The AESC 2015 Update does not present updated avoided cost projections for cord wood and wood pellets in ME, NH and VT because there is very limited historical data on the costs of those two fuels in those states, and the data that is available is based on limited surveys. The data available from the three states suggests that the relationship between wood prices and distillate or crude oil prices is more complex than other fuels. Wood prices appear to be more stable, varying between a narrow range bounded by a floor and a ceiling.

Attachment 1.

Updated Fuel Price Assumptions (Crude Oil, Fuel Oil and Natural Gas)

1. **Fundamental commodity prices – crude oil (West Texas Intermediate “WTI) and natural gas (Henry Hub “HH”).**

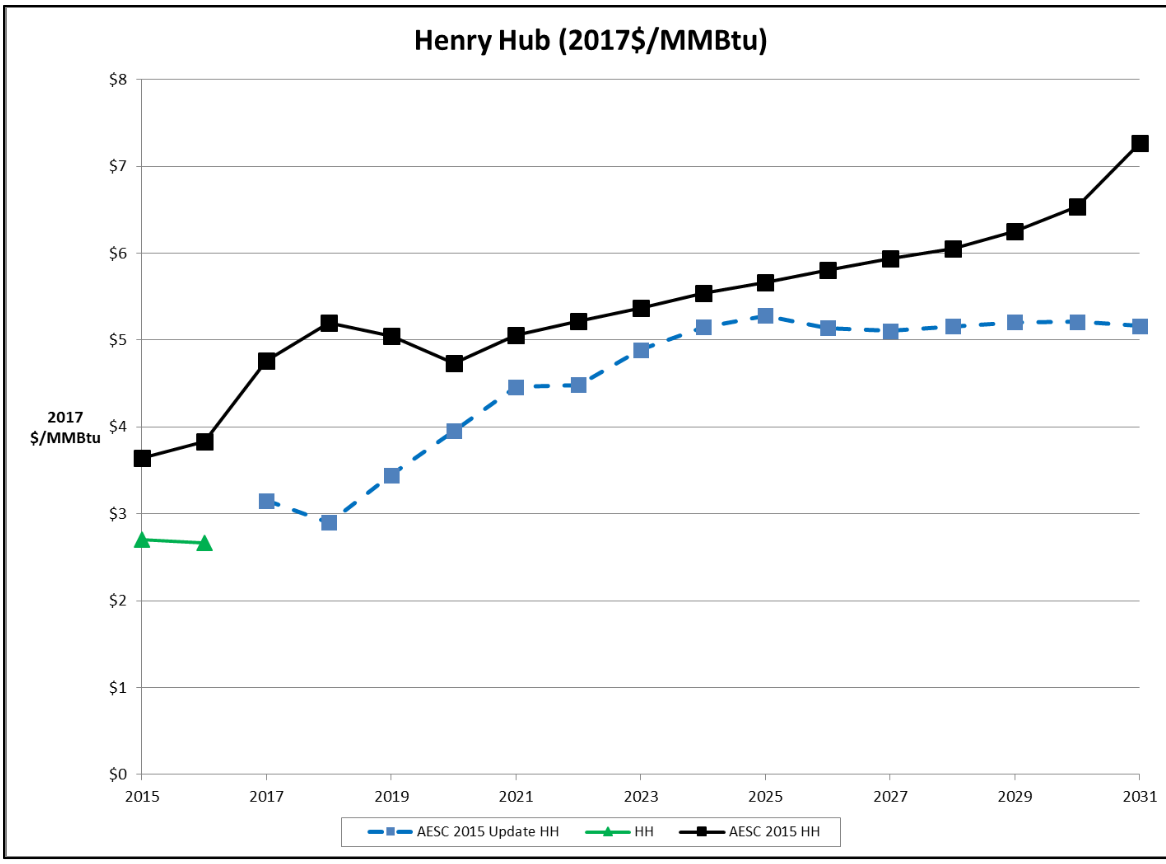
2017-2018: Exchange-traded futures. For this near-term period, NYMEX and ICE futures markets provide a reasonably valid set of energy price drivers (e.g., WTI and Henry Hub) because markets are sufficiently robust in terms of trading participation and volumes to underpin price formation for this study.

2019 through 2031: Average of EIA’s 2016 Annual Energy Outlook (AEO 2016) Reference Case and NYMEX as of September 27, 2016. AEO forecasts continue to be the most commonly-used basis for underpinning domestic energy market analysis. EIA’s underlying National Energy Modeling System (NEMS) is highly and publicly vetted and currently includes a very wide range of forecast assumptions as to future crude oil markets, macroeconomic conditions, drilling productivity, air and carbon regulation, and more.

- **Crude Oil Prices (WTI).** We used the AEO 2016 Reference Case forecast of crude oil prices. This AEO forecast is essentially the same as the AESC 2015 crude price forecast, which we developed by making major reductions to the AEO 2014 Reference Case oil price forecast as needed to reflect the then-recent oil market price crash. In light of relative oil market stability since then, we feel no such adjustment is needed to the AEO 2016 Reference Case WTI forecast.

- **Henry Hub Prices.** We used the AEO 2016 Reference Case forecast of annual Henry Hub prices, and developed monthly prices from NYMERX monthly prices as of 9/27/2016. (This assumption is consistent with prior AESC studies, which have consistently relied upon single point forecasts. There are risks inherent in relying upon any single point forecast. The risks associated with relying upon the AEO 2016 Reference Case forecast of Henry Hub prices for this Update are no greater than the risks that were associated with relying on the AEO 2014 Reference Case forecast of Henry Hub gas prices to underpin AESC 2015. If anything, those risks are lower since the AEO 2014 Reference Case forecast was prepared amid fundamental market uncertainties including the then-recent crash in global oil markets and rapid growth in Marcellus-Utica gas production). The resulting Henry Hub price forecast is lower than AESC 2015, particularly in the years 2017 through 2019, as shown in Figure 1.

Figure 1. Henry Hub projection, AESC 2015 Update versus AESC 2015.



2. **Prices of Distillate and residual fuel oil for electric generation in New England.**
   - **2017-2020.** We used current distillate fuel oil (DFO) futures prices, with the same technical adjustments needed to reflect New England-specific oil markets as we used in AESC 2015, e.g., assuming Boston Harbor prices are similar to New York Harbor prices, and essentially unchanged transportation, storage and handling costs from those in AESC 2015.
   - **2020s through 2031.** We relied on AEO 2016 projections for New England power plant prices, with essentially unchanged transportation, storage and handling costs from AESC 2015.

3. **Natural Gas spot prices in New England.**

Our projection of natural gas spot prices in New England equal our projection of Henry Hub prices plus our projection of basis to New England.

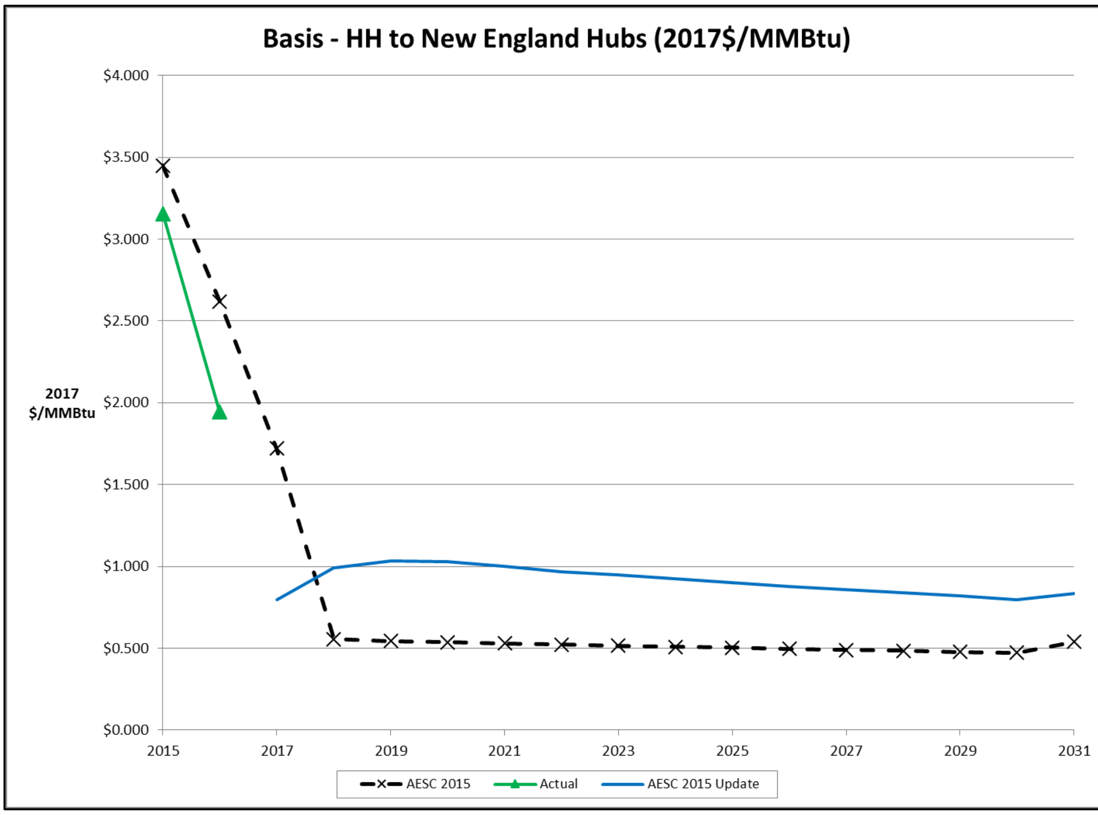
Our projection of basis to New England is based on the following assumptions

- **2017-2021.** For this period, NYMEX and ICE futures markets provide a reasonably valid set of basis projections because markets are sufficiently robust in terms of trading participation and volumes to underpin price formation for this study.
- **2022 through 2031.** We used essentially the same methodology as in AESC 2015, adjusted to reflect our updated assumption of a slower decline in the ratio of winter period - to- base period gas prices. The rationale for our updated assumption of a slower decline in winter month prices

is the change in expectations since AESC 2015 regarding the timing and quantity of new pipeline capacity additions to New England.

The resulting forecast of basis between Henry Hub and New England is lower than AESC 2015 through 2021, reflecting market futures, and higher thereafter, as shown in Figure 2.

Figure 2 Basis to New England projection, AESC 2015 Update versus AESC 2015.



Rationale

The assumption underlying our basis projection is that gas pipeline capacity additions will be limited to only those pipeline projects that are under construction and/or fully subscribed, filed with FERC and likely to be approved by regulators. The pipeline capacity addition assumptions used in AESC 2015 and those we will use in the AESC 2015 Update are presented in the table below.

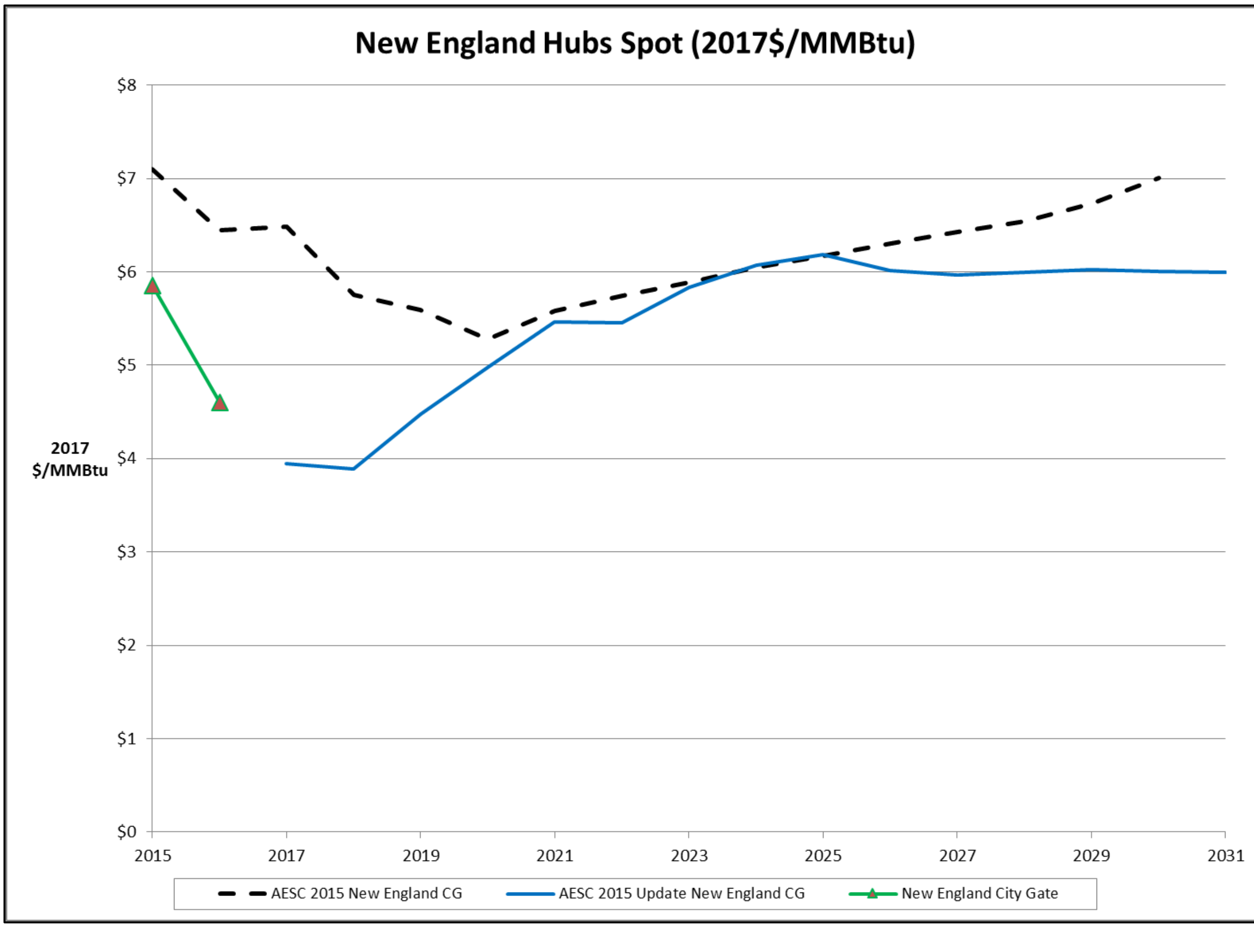
Base Case Assumptions re Gas Pipeline Capacity Expansions to New England				
	AESC 2015 per Exhibit 2-32		AESC 2015 Update	
Project	**In-service date**	**Capacity, MMcf/day**	**In-service date**	**Capacity, MMcf/day**
Tennessee-Connecticut Expansion	November 2017	72	*No change*	
Algonquin Incremental Market (AIM)	November 2017	342	*No change*	
Kinder Morgan/Tennessee – Northeast Energy Direct	November 2018	600		
Spectra – Atlantic Bridge			*November 2018*	*133*
Total		Approx. 1,000		*Approx. 550*

Our assumptions for this update exclude Kinder Morgan's proposed New England Direct (NED) expansion of the Tennessee Gas Pipeline, which has been withdrawn, and Spectra Energy's proposed Access Northeast (ANE) expansion.[1] The proponents of that project have not released new proposals for structuring the project since the August 17, 2016 Massachusetts SJC decision which prohibited Massachusetts electric distribution utilities from entering contracts for firm capacity on that project. We recognize that the Maine Public Utilities has given conditional approval to the concept of Maine electric distribution utilities entering contracts for firm capacity on a pipeline expansion project, where the projected benefits exceed the projected costs (July 19, 2016 Order in Maine Docket No. 2014-00071). However, that Maine order also recognizes that the developer of a major expansion project would require additional contracts with shippers in other New England states in order to meet the minimum contract quantity threshold it required to make the project financially viable. We also recognize that the pipelines serving New England are continuing to examine future expansion projects.

The resulting forecast for natural gas spot prices in New England, shown in Figure 3, is lower than AESC 2015 through 2021 because the lower HH price forecast offsets the higher basis assumption.

[1] Access Northeast is a separate project from Atlantic Bridge.

Figure 3 New England spot gas price, AESC 2015 Update versus AESC 2015.



Wood Fuels

TCR agreed to prepare an updated forecast of prices for wood and wood pellets subject to its analysis of the historical wood price data publicly available from energy offices in Maine, New Hampshire and Vermont. This analysis was to examine the correlation between historical wood prices and fuel oil prices in each state.

ATTACHMENT B – UPDATED ELECTRIC MODELING ASSUMPTIONS

This Attachment describes the electric modeling assumptions the TCR team has updated for the AESC 2015 Update. Unless otherwise noted, all cost data are expressed in real 2017 dollars (2017$).

TCR developed the AESC 2015 avoided electricity costs using the *pCloudAnalytics* (*pCA*) modeling environment and the Power System Optimizer Model ("PSO"). Since then TCR has rebranded pCA as ENELYTIX. TCR used ENELYTIX.to develop the AESC 2015 Update avoided electricity costs.

1. ELECTRIC ENERGY FORECAST ASSUMPTIONS

1.1. Load Forecast Methodology and Input Assumptions

This sub-section describes the development of the updated peak and energy forecast underlying this update to AESC 2015. The AESC 2015 UPDATE developed a load forecast which assumes no impacts of ratepayer funded energy efficiency from 2020 onward using the same methodology as AESC 2015.

The three inputs to this calculation are as follows:

- The ISO New England 2016 CELT Report (2016 CELT) forecasts of Gross Behind Meter PV (BMPV) demand. This represents the gross demand after accounting for the effects of behind meter PV but without other energy efficiency measures.
- The ISO New England 2016 CELT Report (2016 CELT) Net (Gross-PV-PDR) forecast. This forecast represents projected demand reflecting the impacts of reductions from existing energy efficiency programs on load, as well as projected reductions from future energy efficiency programs.
- The level of actual Passive Demand Response (PDR) that has cleared in the Forward Capacity Auctions through 2020. These values represent the impacts of reductions from existing energy efficiency programs on load.

The AESC 2015 UPDATE calculated the forecast as follows:

- 2016 and 2020 - forecast is identical to the CELT net forecast, which reflects the impacts of reductions from existing energy efficiency programs on load.
- 2020 through 2025 - forecast is developed from the CELT net forecast by adding the projected incremental PDR from 2021 onward back on to the CELT net forecast. (This results in a forecast equivalent to deducting the PDR as of 2020 from the CELT Gross forecast from 2021 onward).

- 2026 through 2031   The AESC 2015 UPDATE extrapolates the forecast for these years from 2025 onward using the 2020-2025 compound annual growth rate (CAGR).

1.1.1 ISO-NE Load Forecast

Table 1 and Table 2 summarize the gross annual energy forecast and peak load by ISO-NE area as obtained from the ISO New England 2016 CELT forecast.

Table 1. Gross-BMPV Annual Energy Forecast summary by ISO-NE area[1]

Load Zone	2017 (GWH)	2018 (GWH)	2019 (GWH)	2020 (GWH)	2021 (GWH)	2022 (GWH)	2023 (GWH)	2024 (GWH)	2025 (GWH)	2020-25 CAGR
CT	34,542	34,863	35,077	35,197	35,315	35,460	35,606	35,743	35,870	0.38%
ME	12,793	12,893	12,979	13,049	13,127	13,216	13,310	13,402	13,497	0.68%
NH	12,328	12,450	12,562	12,658	12,755	12,858	12,962	13,063	13,161	0.78%
NMABO	28,836	29,241	29,603	29,912	30,221	30,541	30,863	31,175	31,479	1.03%
RI	9,174	9,248	9,298	9,329	9,367	9,416	9,470	9,527	9,586	0.54%
SEMA	17,328	17,577	17,810	18,015	18,220	18,432	18,646	18,853	19,055	1.13%
VT	6,675	6,702	6,723	6,739	6,759	6,783	6,808	6,833	6,856	0.34%
WCMA	18,665	18,901	19,120	19,309	19,498	19,694	19,891	20,082	20,268	0.97%
Total	140,341	141,875	143,172	144,208	145,262	146,400	147,556	148,678	149,772	0.76%

Table 2. Gross-BMPV Coincident Summer Peak Load Forecast summary by ISO-NE area[2]

Load Zone	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2020-25 CAGR
CT	7,546	7,590	7,629	7,661	7,696	7,737	7,780	7,824	7,868	0.53%
ME	2,206	2,225	2,241	2,256	2,272	2,290	2,308	2,326	2,344	0.77%
NH	2,652	2,690	2,729	2,765	2,802	2,839	2,877	2,914	2,951	1.31%
NMABO	5,964	6,037	6,108	6,175	6,241	6,308	6,375	6,442	6,508	1.06%
RI	2,028	2,046	2,063	2,080	2,099	2,119	2,140	2,160	2,181	0.95%
SEMA	3,572	3,618	3,665	3,710	3,756	3,802	3,848	3,893	3,939	1.21%
VT	1,060	1,062	1,064	1,065	1,067	1,069	1,072	1,075	1,078	0.24%
WCMA	3,760	3,802	3,845	3,888	3,930	3,972	4,015	4,057	4,098	1.06%
Total	28,788	29,070	29,344	29,600	29,863	30,136	30,415	30,691	30,967	0.91%

1.1.2 Modeling Energy Efficiency impacts and developing the Forecast

PDR reduces the level of electric energy consumption that generation resources would have otherwise served. PDR resources participate in the energy market under normal conditions, and the AESC 2015 UPDATE accounts for actual PDR impacts in modeling energy and capacity markets. The AESC 2015 UPDATE excludes the impacts of projected PDR by effectively deducting the projected incremental PDR

[1] ISO New England 2016 CELT Forecast
[2] Ibid.

reductions in demand and energy from ISO-NE's corresponding forecasts of demand and energy prior to developing forecasts. (Incremental to the actual PDR quantity cleared in the last actual FCA).

Table 3 and Table 4 report the projected levels of summer peak and annual energy reduction that the AESC 2015 UPDATE attributes to PDR under the Forecast. The AESC 2015 UPDATE uses the PDR through 2020 that reflects demand reductions due to energy efficiency which has cleared in the capacity auctions through Forward Capacity auction 10 (FCA 10). From 2021 onward, we adjust the ISO-NE PDR projections by keeping the PDR at the 2020 levels, shown in italics.

Table 3. ISO NE Projected Peak Reduction due to PDR

Load Zone	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)
CT	421	459	533	*533*	*533*	*533*	*533*	*533*	*533*
ME	184	181	183	*183*	*183*	*183*	*183*	*183*	*183*
NH	97	102	109	*109*	*109*	*109*	*109*	*109*	*109*
NMBAO	497	569	636	*636*	*636*	*636*	*636*	*636*	*636*
RI	179	204	227	*227*	*227*	*227*	*227*	*227*	*227*
SEMA	259	307	339	*339*	*339*	*339*	*339*	*339*	*339*
VT	132	126	120	*120*	*120*	*120*	*120*	*120*	*120*
WCMA	321	357	413	*413*	*413*	*413*	*413*	*413*	*413*
Total	2,090	2,305	2,561	*2,561*	*2,561*	*2,561*	*2,561*	*2,561*	*2,561*

Table 4. ISO NE Projected Annual Energy Use Reduction Due to PDR

Load Zone	2017 (GWH)	2018 (GWH)	2019 (GWH)	2020 (GWH)	2021 (GWH)	2022 (GWH)	2023 (GWH)	2024 (GWH)	2025 (GWH)
CT	2,357	2,428	2,970	3,338	*3,338*	*3,338*	*3,338*	*3,338*	*3,338*
ME	1,199	1,226	1,263	1,404	*1,404*	*1,404*	*1,404*	*1,404*	*1,404*
NH	542	583	620	676	*676*	*676*	*676*	*676*	*676*
NMBAO	2,688	3,267	3,692	4,189	*4,189*	*4,189*	*4,189*	*4,189*	*4,189*
RI	1020	1,170	1,311	1,459	*1,459*	*1,459*	*1,459*	*1,459*	*1,459*
SEMA	1,401	1,684	1,908	2,164	*2,164*	*2,164*	*2,164*	*2,164*	*2,164*
VT	892	855	806	914	*914*	*914*	*914*	*914*	*914*
WCMA	1,805	2,066	2,341	2,657	*2,657*	*2,657*	*2,657*	*2,657*	*2,657*
Total	11,904	13,279	14,911	16,801	*16,801*	*16,801*	*16,801*	*16,801*	*16,801*

Using these PDR assumptions, the AESC 2015 UPDATE constructed the forecast by subtracting these PDR levels from the gross forecast. Table 5 and Table 6 report the resulting energy and peak projections respectively.

Table 5. AESC 2015 Update Annual Energy Forecast

Load Zone	2017 (GWH)	2018 (GWH)	2019 (GWH)	2020 (GWH)	2021 (GWH)	2022 (GWH)	2023 (GWH)	2024 (GWH)	2025 (GWH)	2020-25 CAGR
CT	32,185	32,435	32,107	31,859	31,977	32,122	32,268	32,405	32,532	0.42%
ME	11,595	11,668	11,716	11,644	11,723	11,812	11,906	11,998	12,093	0.76%
NH	11,786	11,867	11,942	11,982	12,079	12,182	12,286	12,387	12,485	0.83%
NMABO	26,148	25,974	25,911	25,723	26,032	26,352	26,674	26,986	27,290	1.19%
RI	8,154	8,078	7,987	7,870	7,908	7,957	8,011	8,068	8,127	0.64%
SEMA	15,927	15,893	15,902	15,851	16,056	16,268	16,482	16,689	16,891	1.28%
VT	5,783	5,848	5,916	5,825	5,845	5,869	5,894	5,919	5,942	0.40%
WCMA	16,860	16,835	16,778	16,653	16,841	17,037	17,234	17,425	17,611	1.12%
Total	128,438	128,598	128,259	127,407	128,461	129,599	130,755	131,877	132,971	0.86%

Table 6. AESC 2015 Update Coincident Summer Peak Forecast

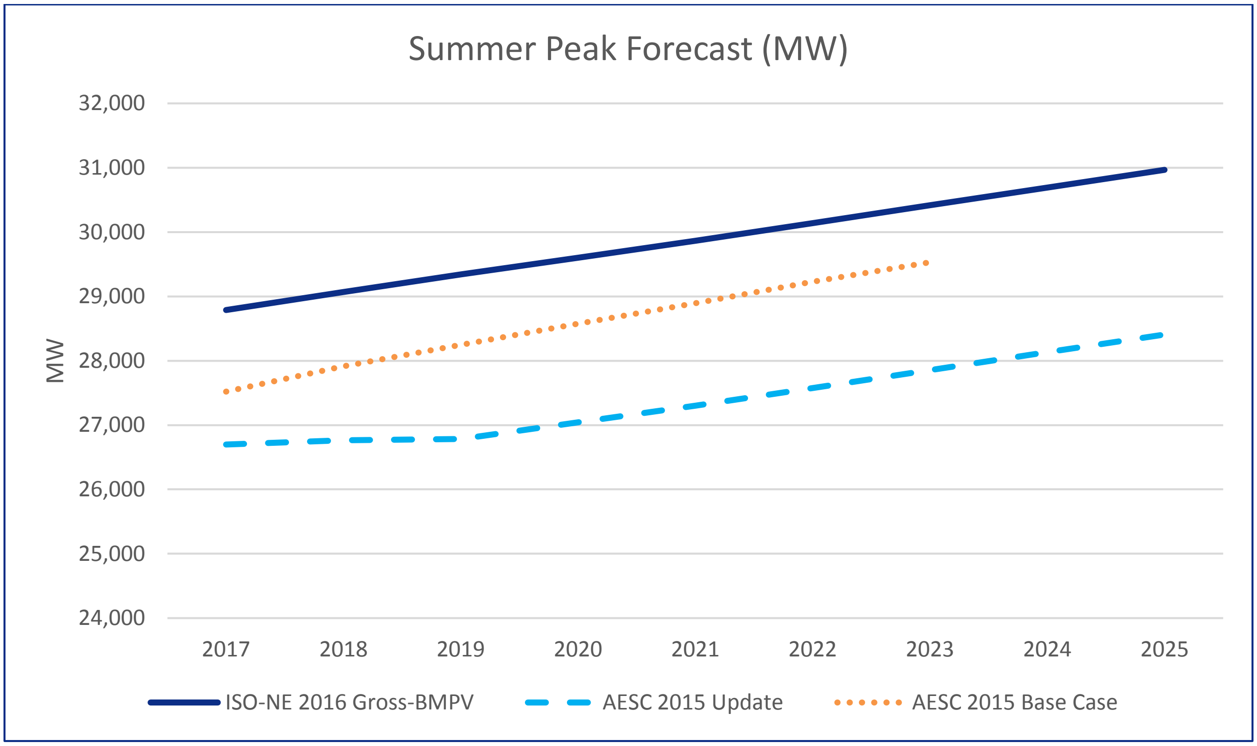
Load Zone	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 (MW)	2024 (MW)	2025 (MW)	2020-25 CAGR
CT	7,125	7,131	7,095	7,128	7,163	7,204	7,247	7,291	7,335	0.57%
ME	2,021	2,044	2,058	2,073	2,089	2,107	2,125	2,143	2,161	0.83%
NH	2,555	2,588	2,619	2,656	2,693	2,730	2,768	2,805	2,842	1.36%
NMABO	5,467	5,468	5,472	5,539	5,605	5,672	5,739	5,806	5,872	1.17%
RI	1,849	1,842	1,837	1,853	1,872	1,892	1,913	1,933	1,954	1.07%
SEMA	3,313	3,311	3,326	3,371	3,417	3,463	3,509	3,554	3,600	1.32%
VT	929	936	943	945	947	949	952	955	958	0.27%
WCMA	3,439	3,445	3,432	3,475	3,517	3,559	3,602	3,644	3,685	1.18%
Total	26,698	26,765	26,782	27,040	27,303	27,576	27,855	28,131	28,407	0.99%

These assumptions result in a forecast for the AESC 2015 Update that is lower than in AESC 2015 for two reasons. First, the ISO-NE 2016 CELT Gross forecast used for the AESC 2015 Update is lower than the ISO-NE 2014 RSP gross load forecast used for AESC 2015. Second, the level of PDR energy reductions through 2020 used for the AESC 2015 Update is greater than the level of PDR reductions through 2018 used for AESC 2015. The table below illustrates the impact of the differences in those two inputs on the energy forecast 2023.

Comparison of Energy Forecasts, New England, 2023				
		Gross Forecast	PDR	Base Case
		a	b	c = a + b
AESC 2015	1	151,530	(13,626)	137,904
AESC 2015 Update	2	147,556	(16,801)	130,755
Difference - GWh	3 = 2 -1	(3,974)	(3,175)	(7,149)
Difference - %	4 = 3/1	-3%	23%	-5%

Figure 1 plots the 2016 CELT Gross BMPV peak demand forecast, the AESC 2015 peak forecast and the AESC 2015 Update peak demand forecast.

Figure 1. Comparison of Peak Forecasts for ISO New England System



1.1.1 **Load Shape**

CELT 2016 provides by load zone projections of summer and winter peak forecasts and annual energy forecasts. However, to simulate the ISO New England market on an hourly basis, PSO requires an hourly load shape for each simulated time frame and area modeled. The AESC 2015 UPDATE constructed load shapes for each area from the following data:

- Template hourly load profiles
- Annual energy and summer/winter peak forecasts for the study period

The AESC 2015 UPDATE uses 2012 historical load shapes by Zone as template load profiles. (The AESC 2015 UPDATE used 2006 load shapes in the AESC 2015 modeling.)These load profiles are consistent with wind generation patterns provided by the National Renewable Energy Laboratory (NREL). Both sets of data are for the same year weather data.

To develop hourly load forecasts for future years, ENELYTIX load algorithms first calendar shift the template load profile to align days of the week and NERC holidays from 2012 to the forecast year. ENELYTIX algorithms then modify calendar shifted template profiles in such a manner that the resulting load shape exhibits the hourly pattern close to that of the template profile while the total energy for the year match the energy forecast and summer and winter peaks match the summer and winter peak forecast.

1.2. Interchange Data

ENELYTIX representation of New England models interchanges with neighboring regions - Canadian provinces of New Brunswick and Quebec and New York ISO - using ISO-NE reported historical hourly interchange schedules for calendar year 2012. Similar to load profiles, interchange flow data are calendar shifted for each forecast year and therefore remain synchronized with load pattern in ISO New England.

1.3. Transmission

The geographic footprint PSO models for this project encompasses the six New England states: Maine, Massachusetts, New Hampshire, Vermont, Rhode Island, and Connecticut. ISO-NE coordinates electricity transmission and wholesale markets in this footprint.

AESC 2015 Update draws its updated transmission topology from the 2016 FERC 715 power flow fillings (2015 MMWG case) for summer peak 2017. Table 7 reports the key interface limits the AESC 2015 UPDATE updated from Exhibit 5-15 in AESC 2015 per the ISO-NE 2015 Regional System Plan (RSP). The Table takes all single line normal and emergency ratings directly from the power flow.

Table 7. Interface limits[3]

Interface	Max	Min
Brayton Station	4002	-4002
Connecticut Export	3745	No Limit
Connecticut Import	2950	-2950
Granite Rel Wind Generation	214	-214
Granite Ridge Unit 1	520	-520
Inner Rumford Export	760	-760
Keene Road Export	230	-9999
Maine - New Hampshire	1900	-1900
Maine Yankee - South	3764	-3764
New England - Boston	4850 | 5700*	-4900 | -5700*
New England - Norwalk Stamford	1650	-1650
New England - Southwest Connecticut	3200	-3200
New England East -West	2800	-2800
New Hampshire-Maine	1375	-1375
Newington Area Generation	3468	-3468
North - South	2100 | 2675*	-2100 | -2675*
Northern New England Scobie 345kV - Scobie + 394	5915	-5915
Northern Vermont Import	2052	-2052
Orrington - South	1325	-1325
Outer Rumford Export	760	-760
Rhode Island Import	1250	-1250
Sandy Pond - South	4300	-4300
Seabrook - South	1745	No Limit
Surowiec - South	1500	-1500
Tiverton Generation	796	-796
Western Connecticut Import	6668	-6668
Whitefld South + GRPW	343	-343

* denotes effective in 2019

1.4. Generating Unit Retirements

Table 8 summarizes approved generation retirements included in the ENELYTIX database. This is an update of Exhibit 5-16 in AESC 2015 for capacity additions scheduled to retire from 2016 onward.

[3] ISO New England, Transmission Interface Transfer Capabilities: *2015 Regional System Plan Assumptions, p60*

Table 8. Approved capacity retirements in ISO-NE

Full Name	Retire Date	Area	Capacity (MW)
BRAYTON POINT 1-4	6/1/2017	SEMA	1,534
Pilgrim	5/31/2019	SEMA	678
Seabrook	3/1/2030	NH	1,247
Total			3,459

1.5. Generating Unit Capacity Additions in ISO-NE interconnection queue

Over the AESC 2015 time horizon, New England will need new generation resources to satisfy renewable portfolio standards and resource adequacy requirements. Since ENELYTIX is not a capacity expansion model, these additions are exogenous. Our assumptions regarding new capacity additions follow.

Table 9 summarizes known near-term new generation additions included in the ENELYTIX database. These are projects listed in ISO-NE's interconnection queue which are either under construction or which have major interconnection studies completed. This is an update of Exhibit 5-17 in AESC 2015 for capacity additions scheduled to come on-line from 2016 onward.

Table 9. New Generation Capacity Additions

Unit	Unit Type	Fuel	Capacity (MW)	Online Date	Area	State
UDR GLASTONBURY	FC		3	2/15/2016	CT	CT
Fair H. Biomass	ST	Biomass	33	3/30/2016	VT	VT
Northfield Upgrade	PSH		295	6/1/2016	WCMA	MA
Canton Mt. Winds	WT		23	11/1/2016	ME	ME
GMP Solar	PV		10	11/15/2016	VT	VT
Blue Sky Wind	WT		185	12/31/2016	ME	ME
Berkshire Wind	WT		20	1/1/2017	WCMA	MA
Salem Harbor CC	CC	NG	716	3/1/2017	NMABO	MA
Brockton CC	CC	NG	332	4/19/2017	SEMA	MA
MATEP CTG	GT	NG	100	6/1/2017	NMABO	MA
Palmer Ren En.	ST	Refuse	37	7/15/2017	WCMA	MA
Spruce Ridge Wind Farm	WT		51	10/31/2017	NH	NH
Bennington_WND	WT		30	12/31/2017	VT	VT
WALLNGFRD6	GT	NG	100	4/1/2018	CT	CT
Medway Peaker - SEMARI	GT	Fuel Oil	208	5/31/2018	SEMA	MA
CPV Towantic	CC	NG	745	6/1/2018	CT	CT
Bridgeport Harbor Expansion	CC	NG	510	5/31/2019	CT	CT
CANAL3	CC	Fuel Oil	333	5/31/2019	SEMA	MA
Clear River Energy Center	CC	NG	500	6/1/2019	RI	RI
Block Island Wind	WT		30	11/1/2016	RI	RI
Total			4,261			

1.6. Renewable Energy Resource Policy Requirements and Additions

This update accounts for resource additions to meet public policy requirements, including those attributable to renewable portfolio standards (RPS), and state or regional procurements.

The AESC 2015 UPDATE uses updated assumptions regarding generic capacity additions attributable to RPS to account for changes in RPS demand resulting from mandated changes in LSE obligations, changes in load forecast, and changes in RPS carve-outs associated with LSE obligations to procure fixed quantities of RPS-eligible energy and renewable energy certificates (RECs). Those carve-outs include the Massachusetts Solar Carve-out and successor programs, as well as Class 1 resources the New England Clean Energy RFP will procure, and offshore wind Massachusetts LSEs will procure pursuant to H4568.[4]

[4] Of these programs, only the Massachusetts solar program is referred to formally as a "carve-out." Other LSE obligations to procure fixed quantities of energy and RECs can also be thought of as reducing RPS demand (and the associated costs avoidable through energy efficiency activities) because they require LSEs to procure fixed quantities of energy and RECs irrespective of their loads.

The update does not include assumptions for Class 1 resources Rhode Island may procure through the New England Clean Energy RFP since we did not have sufficient data on those procurements as of October 6, 2016.

The major updated assumptions the AESC 2015 UPDATE used to determine RPS generic capacity additions are as follows:

Changes in LSE RPS obligations. State by state obligations as a percentage of load by year were updated to account for regulatory developments since the original AESC 2015 analysis, as well as changes in exempt load. In Rhode Island, H.7413 enacted on June 2016 extended the RES to 2035, which was previously set to expire at the end of 2019.[5] In New Hampshire, the 2016 Class III requirement (eligible biomass) was reduced from 8% to 0.5%.[6] In Vermont, H.B. 40, signed by Vermont Governor Peter Shumlin in June 2015, repealed the SPEED goals effective July 1, 2015. This bill also created a mandatory renewable energy standard, which also became effective July 1, 2015.

Massachusetts clean power procurements. In August 2016, Governor Baker signed an energy bill (H4568) requiring the investor-owned utilities to purchase 9,450 GWh/year of clean power, and 1600 MW of offshore wind power.[7] We assume all of the 9,450 GWh will be new Canadian hydropower imported over new HVDC lines, becoming operational in phases over three years from 2021-2023. We assume the 1,600 MW of offshore wind procured will come online in blocks of 400 MW every two years beginning at the end of 2022.[8]

Table 10 presents our assumptions regarding generic capacity additions of hydro imports and offshore wind to comply with the Massachusetts energy bill.

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[5] Rhode Island Legislature, H.7413, http://webserver.rilin.state.ri.us/BillText/BillText16/HouseText16/H7413A.pdf.

[6] NHPUC order 25,844, http://www.puc.nh.gov/Regulatory/Docketbk/2015/15-477/ORDERS/15-477_2015-12-02_ORDER_25844.PDF.

[7] Bill H.4568, An Act to Promote Energy Diversity, https://malegislature.gov/Bills/189/House/H4568.

[8] The capacity factors we assume for offshore wind installed under these procurements were based on data presented in "Massachusetts Offshore Wind Future Cost Study," W. Kempton, S. McClellan, and D. Ozkan, University of Delaware Special Initiative on Offshore Wind, March 2016.

Table 10. Assumed Additions of Clean Energy Resources to Comply with MA Legislation

Resource	Source	Capacity (MW)	Capacity Factor	Energy (GWh	Online Date
Hydro	CA import	449	0.8	3,147	12/31/2020
Hydro	CA import	449	0.8	3,147	12/31/2021
Hydro	CA import	449	0.8	3,147	12/31/2022
Wind	Offshore wind	400	0.45		12/31/2022
Wind	Offshore wind	400	0.46		12/31/2024
Wind	Offshore wind	400	0.46		12/31/2026
Wind	Offshore wind	400	0.47		12/31/2028
Total		2,947		9,440	

PV additions. The updated analysis uses ISO New England's Final 2016 PV Forecast[9] as the basis for generic future PV additions by state. Additionally, we account for 1,600 MWdc of installations expected to be made in Massachusetts under a successor program to replace the RPS Solar Carve-out II, announced by MA DOER in September 2016.[10] ISO-NE did not consider that program at the time of its forecast. The approach used to incorporate the PV forecast is the same as that used in AESC 2015. Additions under the Massachusetts successor program are assumed to occur at a rate of 400 MW per year from 2017 through 2020. We make a simplifying assumption that none of the PV capacity installed in that program is "behind the meter," and therefore the associated energy is not netted from the load forecast.

Mix of RPS generation additions. The AESC 2015 Update uses the mix of renewable technology types and locations for generic RPS generation additions from AESC 2015, scaled as needed to match the gap between demand (net of carve-outs) and known supply.

Table 11 presents our assumptions regarding the remaining generic capacity additions of renewables required in aggregate to comply with the RPS in each New England state. The PV projections in this table

[9] Posted at https://iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf, May 9, 2016.
[10] MA DOER presentation, "Next Generation Solar Incentive Straw Proposal," September 23, 2016, http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/rps-aps/solar-program-straw-proposal-presentation-092316.pptx.

are based on the ISO-NE PV forecast, extended to account for the MA solar successor program, and including associated post-policy additions as per ISO-NE forecasting practice.

Table 11 Assumed Generic Additions of Renewable Resources

Summary of Generic RPS Additions (Nameplate MW, incremental)

AESC 2015 Update

Sum of Nameplate MW	Col														
Row Labels	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Grand Total
Biomass	1.1	19.8	44.7	3.8	4.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	74.0
CHP	15.9	24.0	0.0	1.7	2.4	0.0	0.0	4.6	7.1	7.3	7.4	7.6	7.7	7.9	8.0	101.7
Hydro	1.2	22.2	40.2	4.8	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	70.5
LFG	0.0	46.0	43.6	43.6	27.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	160.8
NGFC	7.2	0.6	8.1	9.4	10.6	9.1	0.5	2.3	2.4	2.4	2.6	2.7	2.8	2.8	2.9	66.4
PV	157.5	188.2	177.1	232.6	128.4	118.8	117.6	117.4	117.5	117.5	117.5	117.5	117.5	117.5	117.5	2060.0
Wind	7.2	134.6	24.5	39.3	45.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	251.6
Grand Total	190.1	435.4	338.2	335.3	221.7	127.9	118.1	124.3	126.9	127.2	127.5	127.8	128.0	128.2	128.4	2784.9

Connecticut clean power procurements. Connecticut investor-owned utilities are authorized to procure up to 4,125 GWh/year of clean energy pursuant to Section 1(c) Public Act 15-107 and Section 7 Public Act 13-303, and procured through the New England Clean Energy RFP (NECERFP).[11] On October 25, 2015, the Procuring States announced the selection of seven projects, representing an aggregate acquisition of approximately 460 MW of wind and solar resources, would advance to contract negotiation. The Table 11 assumptions of generic additions of PV from the ISO New England forecast, and generic additions of wind in our RPS generation additions, are sufficient to account for the 460 MW the NECERFP may select from those seven specific projects.

Other developments that we do not model in the AESC 2015 Update due to insufficient information or uncertainty regarding implementation, but which we expect will affect projections of renewable resource additions in AESC 2018, are as follows:

> **MA GWSA compliance**. The Massachusetts Supreme Judicial Court ruled on May 17, 2016 that regulators must set specific limits on various sources of greenhouse gases to comply with the legal obligation under the GWSA to reduce those emissions. On September 16, Governor Baker signed an executive order directing state officials to develop regulations for specific, annual reductions in greenhouse gas emissions by summer 2017. The implementation plan will need to specify sector-specific targets. It is likely that to meet electricity sector targets, RPS requirements will be increased—e.g., by increasing the annual increment from 1.5% to 2% or 3%. There is also the potential for additional clean energy procurements.
>
> **Energy storage.** Massachusetts recently began its Energy Storage Initiative, to establish an energy storage market structure as well as build strategic partnerships and support storage

[11] Connecticut, Rhode Island and the Commonwealth of Massachusetts (collectively the "Procuring States") issued the *New England Clean Energy RFP* in November 2015. In January 2016, they received 24 proposals in response. https://cleanenergyrfp.com/.

projects at the utility, distribution system, and customer side scale. As part of the initiative, DOER partnered with the Massachusetts Clean Energy Center to develop a comprehensive energy storage study, which was recently released. Among other things, the study recommended regulatory and other changes to facilitate the addition of 600 MW of storage in Massachusetts.

Connecticut Comprehensive Energy Strategy (CES). The Connecticut Department of Energy and Environmental Protection is currently formulating its 2016 economy-wide CES.[12] Pathways for implementation involving clean energy resources include legislation adopting the resulting recommendations, as well as rulemakings by the PURA. We expect the CES to include various measures intended to scale deployment of new clean energy resources such as grid modernization facilitating distributed energy resources, expansion/extension/replacement of existing small and utility scale renewable generation programs and RPS requirements. A draft of the 2016 CES is expected in early Fall 2016, with final release in January 2017.

2. ENVIRONMENTAL POLICY ASSUMPTIONS

2.1. NOx and SO2

None of the New England states have obligations under the Cross State Air Pollution Rule (CSAPR). CSAPR allowance prices are not applicable to New England generators. This update assumes zero allowance prices for NOx and SO2 emissions.

SO2. With the retirement of Brayton Point, SO2 emissions in New England have dropped to levels near zero and correspondingly we assume zero value to SO2 allowances for AESC 2015 Update modeling purposes.

NOx. In accordance with Governor Baker's Executive Order 562 and to meet ongoing federal Clean Air Act requirements, MA DEP in August proposed to replace the Massachusetts Clean Air Interstate Rule (310 CMR 7.32) with a new Ozone Season Nitrogen Oxides Control (310 CMR 7.34). The rule is intended to meet a 2017 (and beyond) budget for NOx emissions from large fossil-fuel-fired electric power and steam generating units during the ozone season (May 1st through September 30th). The proposed Massachusetts Ozone Season NOx budget is 1,799 tons. Given that NOx ozone season emissions from all sources have been decreasing, and over the past five years have ranged between 975 and 1,620 tons, we ascribe zero value to NOx allowances in Massachusetts for AESC 2015 Update modeling purposes.

On September 9, 2016, US EPA approved a State Implementation Plan revision submitted by Connecticut. This revision continues to allow facilities to create and/or use emission credits using NOx Emission Trading and Agreement Orders (TAOs) to comply with the NOx emission limits required by

[12] Section 51 - Comprehensive Energy Planning, CT DEEP, http://www.ct.gov/deep/cwp/view.asp?a=4405&q=500752&deepNav_GID=2121%20.

RCSA section 22a-174-22 (Control of Nitrogen Oxides), which imposes emissions rate limits on generators. It is possible that under this rule NOx DERCs, or allowances, will have value to certain individual generators. Lacking evidence of a liquid market or visible pricing for such allowances in Connecticut, we are assuming their value to be zero.

2.2. Greenhouse Gas Policy Changes and Implications for AESC

The AESC 2015 Update uses the same assumptions regarding the cost of carbon compliance as AESC 2015, but describes ongoing initiatives that may affect the AESC 2018 study assumptions regarding the rates, costs, and impacts of greenhouse gas emissions. These initiatives are too immature for the AESC 2015 Update to uses as the basis for updated assumptions, but they may be sufficiently mature by mid-2017, once their implementation commences.

AESC 2015 Update assumptions regarding the cost of carbon compliance from AESC 2015. The avoided cost calculations in AESC 2015 assume CO_2 regulation under the Regional Greenhouse Gas Initiative (RGGI) through 2020, and CO_2 regulation under EPA's proposed Clean Power Plan (CPP) between 2021 and 2030. AESC 2015 drew its CO_2 emission allowance price assumptions from published simulations of those regimes. The avoided retail energy costs in AESC 2015 reflect those emission allowance price assumptions in the form of embedded environmental costs, i.e., the costs of complying with emissions regulations. Those costs are reflected in the market prices of fuels and/or of electric energy produced fuels. The dominant embedded, and non-embedded, environmental costs are those associated with CO_2 emissions.

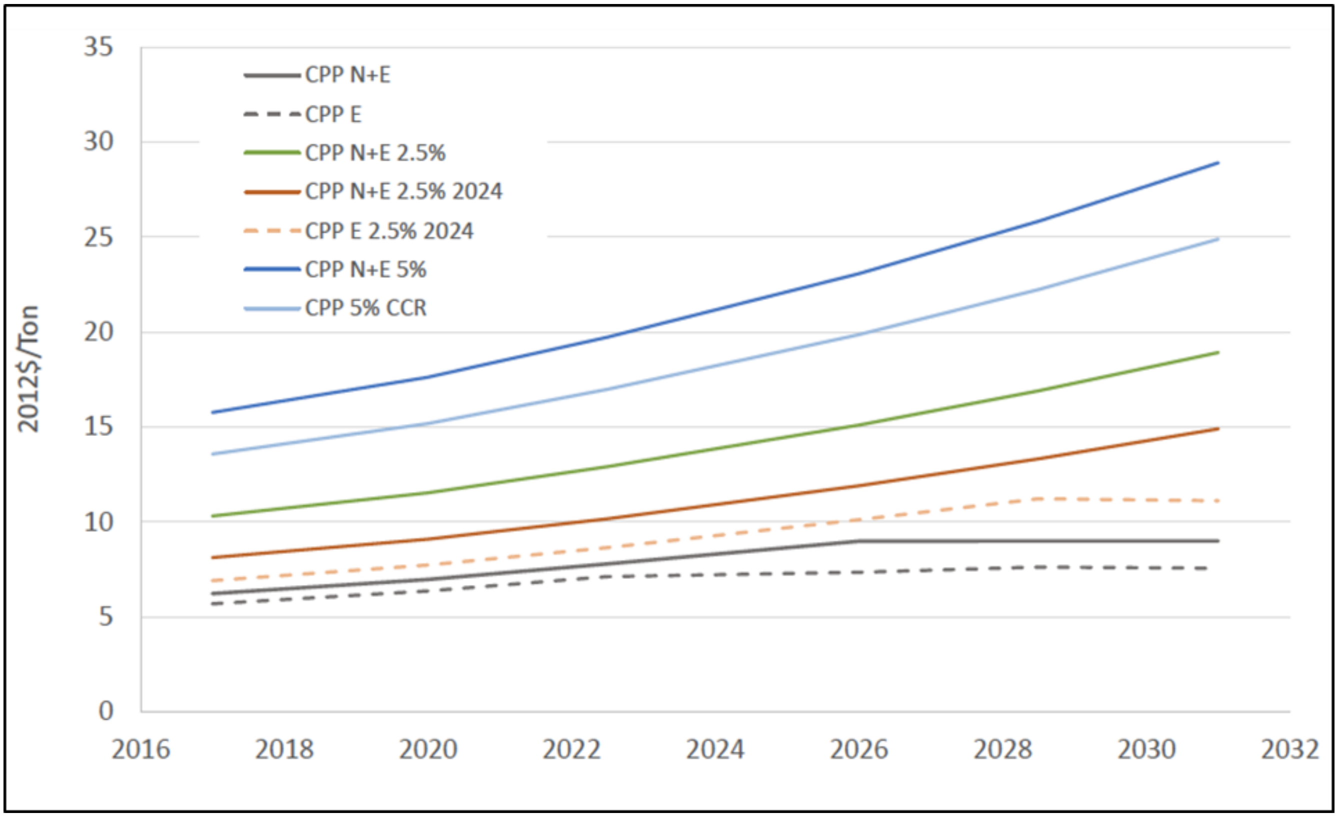
Ongoing initiatives that may affect AESC 2018 assumptions regarding the cost of carbon compliance.

On August 3, 2015, EPA finalized the Clean Power Plan Rule ("Final Rule") to cut carbon pollution from existing power plants, as well as Carbon Pollution Standards to cut carbon emissions from new, modified and reconstructed power plants. The final regulations differ somewhat from the proposed regulations modeled in developing the allowance price projections used in AESC 2015. We are not aware of updated modeling that reflects those changes. The Final Rule was litigated as expected, and on February 9, 2016, the Supreme Court stayed implementation pending judicial review by the DC Circuit Court. It is unclear whether the Rule will survive the challenge. For this and the other reasons above, the AESC 2015 Update makes use of the same CO_2 allowance price trajectory used in AESC 2015.

RGGI is currently in the midst of a program review to develop rules for the post-2020 program. As part of that review, updated simulations and associated CO_2 price trajectories have been developed for a range of scenarios, illustrated in Figure 2. Because the future program design is still in flux, it is not yet clear which of those price trajectories, if any, would most appropriately serve as a basis for updated wholesale energy cost modeling as part of the AESC 2015 Update. RGGI intends to complete the program review by the end of 2016.

The New England states have been conducting negotiations over the pace of carbon reductions have been happening in parallel. The proposal pushed by the Baker administration would require the nine states of the Regional Greenhouse Gas Initiative to curb emissions by five percent each year between 2020 and 2031, though a consensus had yet to emerge as of October 2016.[13]

Figure 2. Projected RGGI CO2 Allowance Prices for a Range of Scenarios[14]



ISO market redesign. NEPOOL initiated a market redesign effort (IMAPP) to better align ISO New England's forward and spot markets with public policy. The objectives of the effort include:

- To create a market mechanism that supports the states' public policy objectives, so that price signals can help achieve an economically efficient resource mix and operations to meet them
- For market pricing in a future with high renewables penetration to support adequately the dispatchable resources (including storage) needed to complement variable resources, and to appropriately compensate nuclear resources for the carbon-reduction capability they provide

[13] "Mass. wants its neighbors to move faster to cut emissions," Boston Globe, August 28, 2016. https://www.bostonglobe.com/metro/2016/08/28/massachusetts-presses-other-states-region-cut-emissions/cwBDURmXXdD32CYfNwlExI/story.html. A reduction of 5 percent per year is twice RGGI's current (through 2020) incremental reduction of 2.5 percent per year.

[14] *DRAFT 2016 RGGI Program Review: CPP Reference Cases & Modelling Scenarios.* June 17, 2016. http://rggi.org

- For wholesale forward and spot market prices to better reflect both the value of carbon reduction and the degree to which non-emitting generation reduces emissions in real time, depending on the time and location that it generates
- To allocate the costs of the products and services procured to meet state public policy objectives across states equitably, given that the benefits are not confined within state lines.

The mechanisms being considered include a spot market carbon adder, a new forward clean energy market, and changes to the existing forward capacity market. The effort is expected to result in a framework document by early December 2016 and a set of new market rules by early- to mid-2017.

GWSA compliance efforts. As discussed, the Massachusetts Supreme Judicial Court ruled that regulators must set specific limits on various sources of greenhouse gases to comply with the legal obligation under the GWSA to reduce those emissions. On September 16, Governor Baker signed an executive order directing state officials to develop regulations for specific, annual reductions in greenhouse gas emissions by summer 2017.

3. ELECTRIC CAPACITY FORECAST ASSUMPTIONS

3.1. Forward Capacity Market Model Update

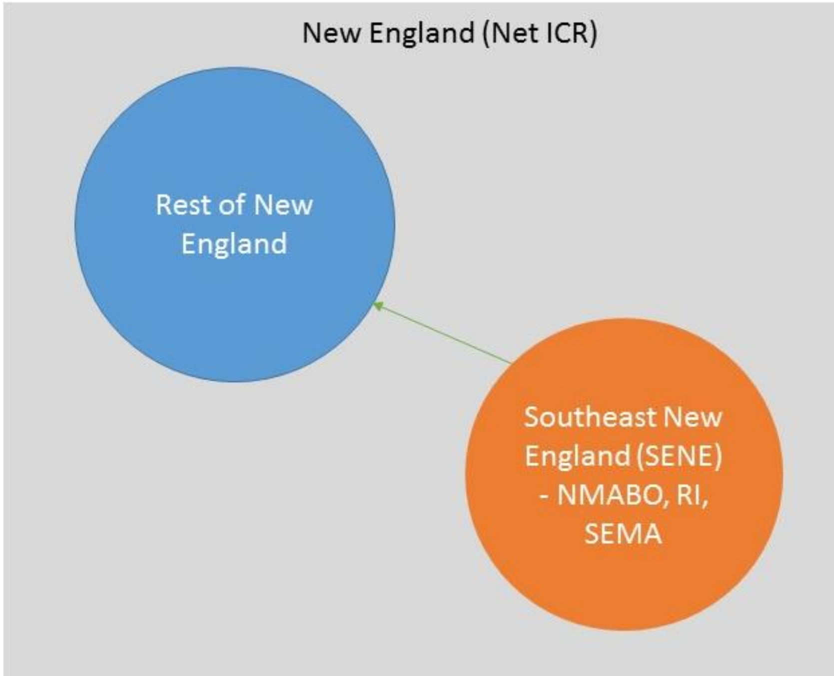
As in AESC 2015, the AESC 2015 Update develops a projection of avoided capacity costs by modeling of the New England capacity market.

The AESC 2015 Update reflects the results of FCAs 9 and 10 which have cleared since AESC 2015, as well as the changes discussed below that have occurred since AESC 2015.

ISO New England introduced new capacity zone. The Update treats Southeast New England (SENE), which combines NMABO, SEMA and RI, as an Import Constrained Zone. According to the installed capacity requirements study published by ISO New England for the 2019-2020 commitment period,[15] SENE is the only import constrained zone. Maine is no longer considered an export constrained zone. As a result, the capacity market structure in New England has simplified to a two-node system as depicted in Figure 3 below.

[15] ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit for the 2019/20 Capacity Commitment Period.

Figure 3. Schematics of FCA Capacity Requirements



As shown in this figure, installed capacity requirements in New England are set as follows:

- System-wide Installed Capacity Requirement (ICR). For the purpose of the study, the AESC 2015 Update uses ICRs that are net of capacity supply provided by imports from Hydro Quebec across HVDC interties (Net ICR represented by the gray rectangle).
- Local Sourcing Requirements (LSRs) for import constraint zone – Southeast New England (SENE) zone, which combines Southeast Massachusetts, Rhode Island and NEMA/Boston zones, is represented by orange circle. Local sourcing requirements specify the minimum level of capacity that must be procured from resources electrically located in the import constrained zone.

The diagram in Figure 3 also depicts a notional Rest of New England Zone (blue circle) for which no requirements are specified explicitly. The arrows between constrained zones and the Rest of New England simply reflect the directions in which excess capacity can be sold. Thus, capacity in a constrained zones that is in the excess of LSR in that zone can be sold to meet system-wide ICR. However, as the direction of the arrow indicates, the reverse is not true, capacity not located in the import constrained zone cannot be sold to meet LSR in that zone.

3.2. Projection of Capacity Requirements in New England

3.2.1 Projection of System-wide Installed Capacity Requirements (ICR)

Table 12 below summarizes actual installed capacity requirements through 2019/20 (FCA 10) and the AESC 2015 UPDATE projections. The AESC 2015 UPDATE projections are based on the analyses described earlier in Section 3.1. PDR resources are modeled as price takers.

Table 12. Projection of System-Wide ICRs

	ISO New England Data[16]			Projection					
Period	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
FCA	8	9	10	11	12	13	14	15	16
Gross Peak (MW)	29,790	30,005	30,230	30,276	30,578	30,883	31,190	31,493	31,794
BMPV (MW)	-	-	369	676	714	746	775	802	828
ICR (MW)	34,922	35,142	35,126	34,820	35,130	35,451	35,778	36,103	36,427
Margin	17.2%	17.1%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%	17.6%
HQICC (MW)	1,068	953	975	975	975	975	975	975	975
Net ICR (MW)	33,854	34,189	34,151	33,845	34,155	34,476	34,803	35,128	35,452

Starting with the data provided in the four most recent ICR studies, we estimated implied reserve margin requirements as the difference between the ICR and the summer peak demand divided by the net peak demand, i.e. gross - BMPV. The resulting simple average of these margins is 17.6%. The AESC 2015 UPDATE assumed that this margin will persist into the future and used this assumption to develop the future ICR projection. The AESC 2015 UPDATE also assumed that the rating of existing import capacity from Hydro Quebec will remain at 975 MW. The AESC 2015 UPDATE calculated net ICR as the ICR minus the HQICC.

3.2.2 Projection of Local Sourcing Requirements (LSRs) for Southeast New England (SENE) Import Constrained Zones

Local Sourcing Requirements are minimum levels of installed capacity that must be procured within an import constrained zone. FCA 10 identified Southeast New England (SENE), consisting of NMABO, SEMA and RI, to be the only zone requiring LSR. Table 13 below summarizes TCR's projection of Local Sourcing Requirements for SENE.

[16] ISO New England Installed Capacity Requirement, Local Sourcing Requirements, and Maximum Capacity Limit studies for 2017/18, 2018/19 and 2019/20 capability periods

Table 13. Projection of LSRs for SENE

	ISONE Data	Projection					
Period	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26
FCA	10	11	12	13	14	15	16
Peak (MW)	13,342	13,188	13,339	13,492	13,644	13,797	13,948
N-1 Import Limit	5,700	5,700	5,700	5,700	5,700	5,700	5,700
LSR	10,028	9,846	10,024	10,205	10,384	10,564	10,742
Margin	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%	17.9%

Starting with the data provided in the most recent ICR studies[17], we estimated implied reserve margin requirements for import constrained zones. The implied reserve margin was computed as a difference between the sum of LSR and N-1 contingency import limit into the zone and the 90/10 peak demand in that zone divided by the 90/10 peak demand. 90/10 peak demand is the ISO New England estimated summer peak which is likely to occur under the 1 in 10 years most critical weather conditions. TCR computed a simple average of the zone's margin and assumed that this margin will persist in the future. Using this assumption, TCR projected future LSR values for SENE.

3.2.3 PDR Levels

Table 14 reports the PDR levels used in the forecast.

Table 14. PDR levels used in modeling FCA

Base	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
ISO-NE	2,561	2,561	2,561	2,561	2,561	2,561
SENE	1,202	1,202	1,202	1,202	1,202	1,202

3.3. Demand Curve Assumptions

In July 2016, FERC accepted[18] ISO-NE's proposal[19] for a new "Marginal Reliability Impact" (MRI) based approach to develop system wide and zone specific sloped demand curves for FCA 11 (2020/2021). However, details of the sloped demand curve are yet to be finalized. Therefore, the AERSC 2015 Update continues to use the linear system wide demand curve used in FCA10 for capacity market modeling.

[17] ICR study for 2014/15 did not contain sufficient details for this analysis and was not used.
[18]FERC Docket ER16-1434 Available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14287974
[19] ISO-NE and NEPOOL filing to FERC Available at: https://www.iso-ne.com/static-assets/documents/2016/04/er16-1434-000.pdf

FCA10, cleared in February of 2016, used a linear system wide demand curve and a vertical import constrained zone demand curve. Based on the information from FCA 10, the AESC 2015 Update models the FCM market using the following design of the system-wide and zone-specific demand curves.

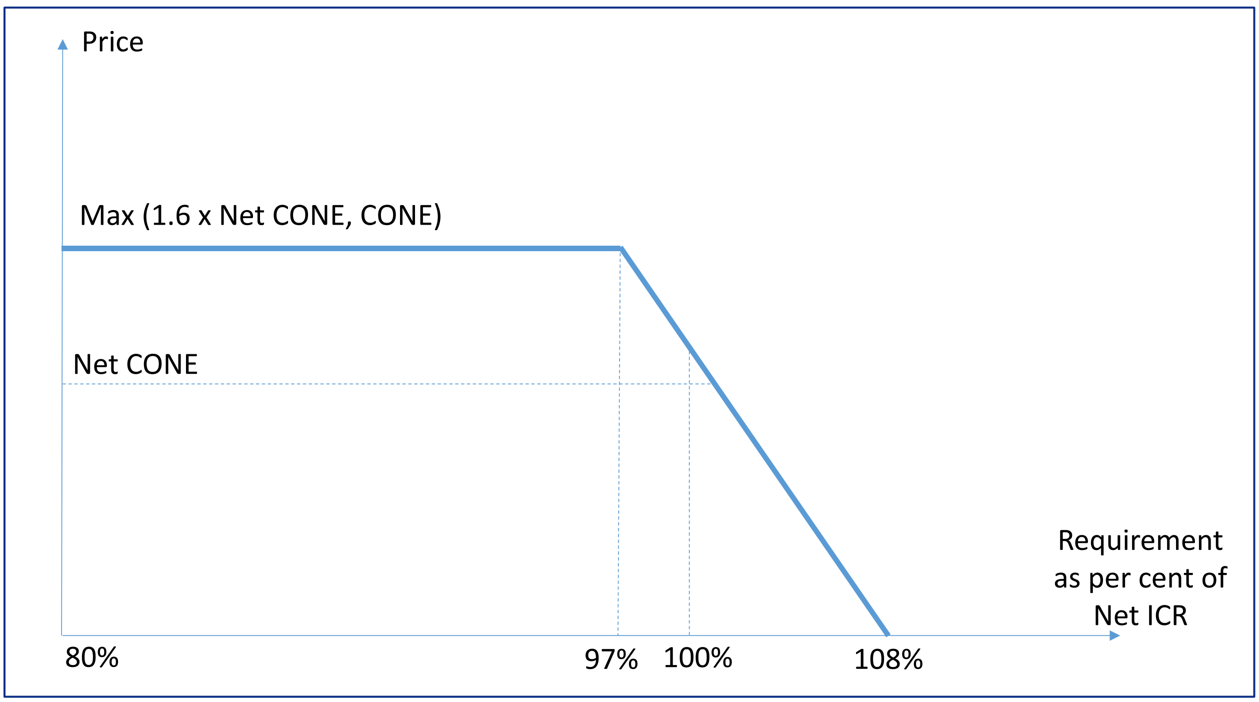
3.3.1 System-wide Curve

Figure 4 depicts the system-wide sloped demand curve. The curve expresses the system-wide capacity price as a function of the relative level of supply expressed as a per cent of Net ICR. The price floor is zero and the price cap is the maximum between 1.6 times of Net CONE and CONE (CONE stands for the Cost of New Entry).

3.3.2 Vertical Demand Curve for SENE

Consistent with FCA 10, the AESC 2015 Update uses a "vertical" demand curve for the SENE zone. Under that approach, capacity in the SENE zone must be greater or equal LSRs but once they are greater or equal LSRs, capacity price in that zone will be equal to the system-wide capacity price. In other words, no locational price separation between zones in New England may be projected in this update.

Figure 4. System-Wide Sloped Demand Curve



Along the demand curve, the price reaches the cap when the supply falls below 97% of Net ICR and falls to zero when supply exceeds 108% of Net ICR. The net ICR values for each Commitment period are as specified in Table 12.

Table 15 reports the updated values for CONE and Net CONE.[20]

Table 15. CONE and Net CONE Assumptions

Parameter	Value in real 2019$/kW-month	Value (in real 2017 $/kW-year)
CONE	14.29	165.31
Net CONE	10.81	125.05
1.6 x Net CONE	17.296	200.08

[20] "ISO New England Installed Capacity Requirement, Local Sourcing Requirements and Capacity Requirement Values for the System-Wide Capacity Demand Curve for the 2019/20 Capacity Commitment Period" Jan 2016

ATTACHMENT 3

AESC 2015 Update financial parameters

Comparison of Financial Parameter Estimates			
Parameter / Source & Vintage	**AESC 2013**	**AESC 2015**	**AESC 2015 Update**
	Mar-13	11/17/14	9/30/16
Long Term Nominal Rate	3.39%	4.36%	3.46%
Source	30 year T-Bills over last six years.	Composite CBO thru 2024, AEO 2014 thru 2030	GDP Price Index - Composite of CBO for 2017 thru 2026 and AEO 2016 for 2017 thru 2031
Inflation Rate (GDP Deflator)	**2.00%**	**1.88%**	**2.00%**
Source	Consistent with 20 year historic average inflation of 2.07%, but slightly lower to reflect economic forecasts.	Composite CBO thru 2024, AEO 2014 thru 2030	10 year treasury note - Composite of CBO for 2017 thru 2026 and AEO 2016 for 2017 thru 2031
Long Term Real Rate	**1.36%**	**2.43%**	**1.43%**

Inflators/Deflators to convert nominal $ to 2017$

Year	GDP Chain-Type Price Index	Annual Inflation	Inflators/Deflators to convert nominal $ to 2017$
2000	81.89	2.28%	1.385
2001	83.75	2.28%	1.354
2002	85.04	1.53%	1.334
2003	86.74	1.99%	1.308
2004	89.12	2.75%	1.273
2005	91.99	3.22%	1.233
2006	94.81	3.07%	1.196
2007	97.34	2.66%	1.165
2008	99.25	1.96%	1.143
2009	100	0.76%	1.134
2010	101.22	1.22%	1.121
2011	103.31	2.06%	1.098
2012	105.17	1.80%	1.079
2013	106.73	1.49%	1.063
2014	108.94	2.07%	1.041
2015	110.09	1.05%	1.030
2016	111.43	1.22%	1.018
2017	113.44	1.80%	1.000
2018	115.48	1.80%	0.982
2019	117.67	1.90%	0.964
2020	119.91	1.90%	0.946
2021	122.31	2.00%	0.927
2022	124.75	2.00%	0.909
2023	127.25	2.00%	0.891
2024	129.79	2.00%	0.874
2025	132.52	2.10%	0.856
2026	135.30	2.10%	0.838
2027	137.98	1.98%	0.822
2028	140.74	2.00%	0.806
2029	143.64	2.06%	0.790
2030	146.66	2.10%	0.773
2031	149.87	2.19%	0.757

Data Sources:

1	Values through 2016 from Bureau of Economic Analysis, Table 1.1.9, as follows: 2014, Avg Q2 & Q3 2015, Avg Q2 & Q3 2016, Avg Q2 & Q3 (latter at same deflator as 2015q3 vs 2015Q2 http://bea.gov	
2	Values for 2017 through 2026 derived from An Update to the Budget and Economic Outlook: 2016 to 2026, Congressional Budget Office, August 2016, Table B-1, GDP Price index https://www.cbo.gov/publication/51908	
3	Values for 2026 onward based on average inflation rate from AEO 2016 from 2026 to 2031 of	2.07%

Table One: Avoided Cost of Electricity (2017 $) Results :

ME
Maine

State ME

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	1.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2017	0.0479	0.0416	0.0334	0.0248	130.7	*0.0*	65.4	0.0037	0.0022	-0.0025	0.0009		0.0037	0.0022	-0.0025	0.0009		0.0483	0.0478	0.0515	0.0493
2018	0.0477	0.0410	0.0321	0.0246	151.9	*0.0*	75.9	0.0019	0.0012	0.0000	0.0000		0.0019	0.0012	0.0000	0.0000		0.0480	0.0475	0.0512	0.0490
2019	0.0518	0.0453	0.0379	0.0303	101.9	*0.0*	50.9	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0476	0.0470	0.0507	0.0486
2020	0.0566	0.0483	0.0468	0.0346	104.2	*0.0*	52.1	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0471	0.0466	0.0502	0.0481
2021	0.0614	0.0530	0.0497	0.0380	111.3	145.9	128.6											0.0459	0.0454	0.0489	0.0468
2022	0.0624	0.0537	0.0513	0.0394	104.9	137.4	121.2											0.0446	0.0441	0.0476	0.0456
2023	0.0664	0.0572	0.0554	0.0436	98.6	129.1	113.9											0.0434	0.0429	0.0463	0.0443
2024	0.0693	0.0597	0.0581	0.0472	102.7	134.5	118.6											0.0422	0.0417	0.0449	0.0430
2025	0.0716	0.0622	0.0628	0.0494	113.2	148.2	130.7											0.0409	0.0404	0.0436	0.0418
2026	0.0715	0.0620	0.0644	0.0502	123.9	162.3	143.1											0.0397	0.0392	0.0423	0.0405
2027	0.0726	0.0629	0.0650	0.0510	134.2	175.8	155.0											0.0384	0.0380	0.0409	0.0392
2028	0.0740	0.0642	0.0692	0.0533	144.8	189.6	167.2											0.0372	0.0367	0.0396	0.0379
2029	0.0757	0.0660	0.0721	0.0551	156.1	204.5	180.3											0.0359	0.0355	0.0383	0.0367
2030	0.0774	0.0684	0.0741	0.0566	171.4	224.6	198.0											0.0347	0.0343	0.0369	0.0354
2031	0.0778	0.0695	0.0801	0.0582	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2032	0.0791	0.0711	0.0836	0.0600	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2033	0.0805	0.0727	0.0873	0.0618	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2034	0.0818	0.0744	0.0912	0.0636	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2035	0.0832	0.0761	0.0953	0.0656	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2036	0.0846	0.0778	0.0995	0.0675	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2037	0.0861	0.0796	0.1040	0.0696	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2038	0.0875	0.0815	0.1086	0.0717	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2039	0.0890	0.0833	0.1134	0.0738	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2040	0.0905	0.0853	0.1185	0.0761	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2041	0.0921	0.0872	0.1237	0.0784	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2042	0.0936	0.0892	0.1292	0.0807	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2043	0.0952	0.0913	0.1350	0.0832	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2044	0.0968	0.0934	0.1410	0.0857	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2045	0.0985	0.0955	0.1473	0.0883	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2046	0.1002	0.0977	0.1538	0.0910	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2047	0.1019	0.1000	0.1607	0.0937	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
Levelized Costs																					
10 years (2017-2026)	0.0603	0.0521	0.0488	0.0378	114.6	83.2	98.9	0.0006	0.0004	-0.0003	0.0001	0.0000	0.0006	0.0004	-0.0003	0.0001	0.0000	0.045	0.044	0.048	0.046
15 years (2017-2031)	0.0650	0.0565	0.0560	0.0431	127.6	121.0	124.3	0.0004	0.0002	-0.0002	0.0001	0.0000	0.0004	0.0002	-0.0002	0.0001	0.0000	0.042	0.042	0.045	0.043
30 years (2017-2046)	0.0757	0.0684	0.0819	0.0569	150.3	171.3	160.8	0.0002	0.0001	-0.0001	0.0000	0.0000	0.0002	0.0001	-0.0001	0.0000	0.0000	0.039	0.038	0.041	0.040

NOTES:

General: All Avoided Costs are in Year 2017 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1. Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)
2. Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.
3. Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%
4. PTF loss = 2.20%
5. Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: ME

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2017	0.0433	0.0376	0.0301	0.0222			121.0	17.0%	0.0006	0.0038	0.0024	-0.0029	0.0011	0.0038	0.0024	-0.0029	0.0011
2018	0.0430	0.0369	0.0287	0.0218	0.0022	0.0015	140.6	17.2%	0.0008	0.0020	0.0013	0.0000	0.0000	0.0020	0.0013	0.0000	0.0000
2019	0.0466	0.0407	0.0339	0.0269	0.0014	0.0010	94.3	17.6%	0.0009	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2020	0.0509	0.0434	0.0420	0.0308	0.0014	0.0010	96.5	17.6%	0.0010	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2021	0.0556	0.0479	0.0449	0.0341	0.0002	0.0002	103.1	17.6%	0.0007								
2022	0.0569	0.0489	0.0467	0.0358	0.0002	0.0002	97.1	17.6%	0.0004								
2023	0.0606	0.0521	0.0505	0.0397	0.0002	0.0002	91.3	17.6%	0.0003								
2024	0.0633	0.0544	0.0530	0.0430	0.0002	0.0002	95.1	17.6%	0.0003								
2025	0.0654	0.0567	0.0573	0.0450	0.0002	0.0002	104.8	17.6%	0.0003								
2026	0.0653	0.0566	0.0588	0.0457	0.0002	0.0002	114.7	17.6%	0.0003								
2027	0.0663	0.0574	0.0593	0.0464	0.0002	0.0002	124.3	17.6%	0.0003								
2028	0.0676	0.0586	0.0632	0.0486	0.0002	0.0002	134.0	17.6%	0.0003								
2029	0.0691	0.0603	0.0658	0.0502	0.0002	0.0002	144.5	17.6%	0.0003								
2030	0.0707	0.0625	0.0676	0.0516	0.0002	0.0002	158.7	17.6%	0.0003								
2031	0.0711	0.0634	0.0731	0.0531	0.0002	0.0002	165.1	17.6%	0.0003								
2032	0.0723	0.0649	0.0764	0.0547	0.0002	0.0002	165.1	17.6%	0.0003								
2033	0.0735	0.0664	0.0798	0.0564	0.0002	0.0002	165.1	17.6%	0.0003								
2034	0.0748	0.0679	0.0834	0.0581	0.0002	0.0002	165.1	17.6%	0.0003								
2035	0.0760	0.0695	0.0871	0.0598	0.0002	0.0002	165.1	17.6%	0.0003								
2036	0.0773	0.0711	0.0910	0.0616	0.0002	0.0002	165.1	17.6%	0.0003								
2037	0.0787	0.0727	0.0950	0.0635	0.0002	0.0002	165.1	17.6%	0.0003								
2038	0.0800	0.0744	0.0993	0.0654	0.0002	0.0002	165.1	17.6%	0.0003								
2039	0.0814	0.0761	0.1037	0.0674	0.0002	0.0002	165.1	17.6%	0.0003								
2040	0.0827	0.0779	0.1084	0.0695	0.0002	0.0002	165.1	17.6%	0.0003								
2041	0.0842	0.0797	0.1132	0.0716	0.0002	0.0002	165.1	17.6%	0.0003								
2042	0.0856	0.0815	0.1182	0.0738	0.0002	0.0002	165.1	17.6%	0.0003								
2043	0.0870	0.0834	0.1235	0.0760	0.0002	0.0002	165.1	17.6%	0.0003								
2044	0.0885	0.0854	0.1290	0.0783	0.0002	0.0002	165.1	17.6%	0.0003								
2045	0.0900	0.0873	0.1348	0.0807	0.0002	0.0002	165.1	17.6%	0.0003								
2046	0.0916	0.0894	0.1408	0.0831	0.0002	0.0002	165.1	17.6%	0.0003								
2047	0.0931	0.0914	0.1471	0.0857	0.0002	0.0002	165.1	17.6%	0.0003								
Levelized Costs																	
10 years (2017-2026)	0.0548	0.0472	0.0442	0.0342	0.0007	0.0005	106.1	0.1749	0.0006	0.0006	0.0004	-0.0003	0.0001	0.0006	0.0004	-0.0003	0.0001
15 years (2017-2031)	0.0591	0.0513	0.0508	0.0390	0.0005	0.0004	118.2	0.1753	0.0005	0.0004	0.0003	-0.0002	0.0001	0.0004	0.0003	-0.0002	0.0001
30 years (2017-2046)	0.0690	0.0624	0.0748	0.0517	0.0004	0.0003	139.1	0.1756	0.0004	0.0002	0.0001	-0.0001	0.0000	0.0002	0.0001	-0.0001	0.0000

NOTES: General All Avoided Costs are in Year 2017 Dollars
periods:

Table One: Avoided Cost of Electricity (2017 $) Results :

NH
New Hampshire

State NH

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	1.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2017	0.0559	0.0496	0.0415	0.0328	130.7	*0.0*	65.4	0.0033	0.0035	0.0123	0.0000		0.0033	0.0035	0.0123	0.0000		0.0483	0.0478	0.0515	0.0493
2018	0.0547	0.0481	0.0392	0.0317	151.9	*0.0*	75.9	0.0017	0.0018	0.0000	0.0000		0.0017	0.0018	0.0000	0.0000		0.0480	0.0475	0.0512	0.0490
2019	0.0589	0.0524	0.0450	0.0374	101.9	*0.0*	50.9	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0476	0.0470	0.0507	0.0486
2020	0.0637	0.0555	0.0540	0.0418	104.2	*0.0*	52.1	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0471	0.0466	0.0502	0.0481
2021	0.0703	0.0619	0.0587	0.0470	111.3	145.9	128.6											0.0459	0.0454	0.0489	0.0468
2022	0.0719	0.0632	0.0608	0.0489	104.9	137.4	121.2											0.0446	0.0441	0.0476	0.0456
2023	0.0761	0.0668	0.0651	0.0532	98.6	129.1	113.9											0.0434	0.0429	0.0463	0.0443
2024	0.0791	0.0694	0.0679	0.0569	102.7	134.5	118.6											0.0422	0.0417	0.0449	0.0430
2025	0.0814	0.0720	0.0726	0.0592	113.2	148.2	130.7											0.0409	0.0404	0.0436	0.0418
2026	0.0808	0.0713	0.0738	0.0595	123.9	162.3	143.1											0.0397	0.0392	0.0423	0.0405
2027	0.0815	0.0718	0.0740	0.0598	134.2	175.8	155.0											0.0384	0.0380	0.0409	0.0392
2028	0.0825	0.0726	0.0777	0.0617	144.8	189.6	167.2											0.0372	0.0367	0.0396	0.0379
2029	0.0846	0.0749	0.0810	0.0639	156.1	204.5	180.3											0.0359	0.0355	0.0383	0.0367
2030	0.0859	0.0769	0.0826	0.0651	171.4	224.6	198.0											0.0347	0.0343	0.0369	0.0354
2031	0.0863	0.0780	0.0887	0.0667	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2032	0.0876	0.0796	0.0923	0.0685	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2033	0.0890	0.0812	0.0960	0.0703	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2034	0.0904	0.0829	0.0999	0.0722	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2035	0.0918	0.0846	0.1040	0.0741	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2036	0.0932	0.0864	0.1082	0.0761	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2037	0.0946	0.0882	0.1127	0.0781	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2038	0.0961	0.0900	0.1173	0.0802	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2039	0.0976	0.0919	0.1222	0.0824	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2040	0.0991	0.0938	0.1273	0.0847	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2041	0.1007	0.0958	0.1326	0.0870	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2042	0.1022	0.0978	0.1381	0.0894	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2043	0.1038	0.0999	0.1439	0.0918	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2044	0.1055	0.1020	0.1499	0.0943	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2045	0.1071	0.1042	0.1562	0.0969	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2046	0.1088	0.1064	0.1628	0.0996	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2047	0.1105	0.1086	0.1697	0.1024	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
Levelized Costs																					
10 years (2017-2026)	0.0689	0.0607	0.0574	0.0464	114.6	83.2	98.9	0.0005	0.0006	0.0013	0.0000	0.0000	0.0005	0.0006	0.0013	0.0000	0.0000	0.045	0.044	0.048	0.046
15 years (2017-2031)	0.0736	0.0651	0.0646	0.0517	127.6	121.0	124.3	0.0004	0.0004	0.0009	0.0000	0.0000	0.0004	0.0004	0.0009	0.0000	0.0000	0.042	0.042	0.045	0.043
30 years (2017-2046)	0.0843	0.0770	0.0907	0.0654	150.3	171.3	160.8	0.0002	0.0002	0.0005	0.0000	0.0000	0.0002	0.0002	0.0005	0.0000	0.0000	0.039	0.038	0.041	0.040

NOTES:

General All Avoided Costs are in Year 2017 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)
2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.
3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%
4 PTF loss = 2.20%
5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: NH

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2017	0.0433	0.0376	0.0302	0.0222			121.0	17.0%	0.0079	0.0036	0.0036	0.0047	0.0000	0.0036	0.0036	0.0047	0.0000
2018	0.0430	0.0369	0.0287	0.0218	0.0024	0.0016	140.6	17.2%	0.0073	0.0019	0.0019	0.0000	0.0000	0.0019	0.0019	0.0000	0.0000
2019	0.0466	0.0407	0.0339	0.0269	0.0015	0.0010	94.3	17.6%	0.0074	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2020	0.0509	0.0434	0.0420	0.0308	0.0015	0.0010	96.5	17.6%	0.0076	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2021	0.0556	0.0479	0.0450	0.0342	0.0002	0.0002	103.1	17.6%	0.0089								
2022	0.0569	0.0489	0.0468	0.0358	0.0002	0.0002	97.1	17.6%	0.0091								
2023	0.0606	0.0521	0.0506	0.0397	0.0002	0.0002	91.3	17.6%	0.0092								
2024	0.0633	0.0544	0.0530	0.0430	0.0002	0.0002	95.1	17.6%	0.0093								
2025	0.0654	0.0567	0.0573	0.0450	0.0002	0.0002	104.8	17.6%	0.0093								
2026	0.0653	0.0565	0.0589	0.0457	0.0002	0.0002	114.7	17.6%	0.0089								
2027	0.0663	0.0574	0.0594	0.0464	0.0002	0.0002	124.3	17.6%	0.0085								
2028	0.0676	0.0586	0.0633	0.0486	0.0002	0.0002	134.0	17.6%	0.0081								
2029	0.0691	0.0603	0.0659	0.0502	0.0002	0.0002	144.5	17.6%	0.0084								
2030	0.0707	0.0624	0.0677	0.0516	0.0002	0.0002	158.7	17.6%	0.0081								
2031	0.0711	0.0634	0.0732	0.0531	0.0002	0.0002	165.1	17.6%	0.0081								
2032	0.0723	0.0649	0.0765	0.0547	0.0002	0.0002	165.1	17.6%	0.0081								
2033	0.0735	0.0664	0.0799	0.0564	0.0002	0.0002	165.1	17.6%	0.0081								
2034	0.0748	0.0679	0.0835	0.0581	0.0002	0.0002	165.1	17.6%	0.0081								
2035	0.0760	0.0695	0.0872	0.0598	0.0002	0.0002	165.1	17.6%	0.0081								
2036	0.0773	0.0711	0.0911	0.0617	0.0002	0.0002	165.1	17.6%	0.0082								
2037	0.0787	0.0727	0.0952	0.0635	0.0002	0.0002	165.1	17.6%	0.0082								
2038	0.0800	0.0744	0.0995	0.0655	0.0002	0.0002	165.1	17.6%	0.0082								
2039	0.0814	0.0761	0.1039	0.0674	0.0002	0.0002	165.1	17.6%	0.0082								
2040	0.0828	0.0779	0.1086	0.0695	0.0002	0.0002	165.1	17.6%	0.0082								
2041	0.0842	0.0797	0.1134	0.0716	0.0002	0.0002	165.1	17.6%	0.0082								
2042	0.0856	0.0815	0.1185	0.0738	0.0002	0.0002	165.1	17.6%	0.0082								
2043	0.0871	0.0834	0.1238	0.0760	0.0002	0.0002	165.1	17.6%	0.0082								
2044	0.0885	0.0854	0.1293	0.0783	0.0002	0.0002	165.1	17.6%	0.0082								
2045	0.0901	0.0873	0.1351	0.0807	0.0002	0.0002	165.1	17.6%	0.0082								
2046	0.0916	0.0894	0.1411	0.0832	0.0002	0.0002	165.1	17.6%	0.0082								
2047	0.0931	0.0914	0.1474	0.0857	0.0002	0.0002	165.1	17.6%	0.0082								
Levelized Costs																	
10 years (2017-2026)	0.0548	0.0472	0.0442	0.0342	0.0007	0.0005	106.1	0.1749	0.0085	0.0006	0.0006	0.0005	0.0000	0.0006	0.0006	0.0005	0.0000
15 years (2017-2031)	0.0591	0.0513	0.0509	0.0390	0.0005	0.0004	118.2	0.1753	0.0084	0.0004	0.0004	0.0003	0.0000	0.0004	0.0004	0.0003	0.0000
30 years (2017-2046)	0.0690	0.0624	0.0749	0.0518	0.0004	0.0003	139.1	0.1756	0.0083	0.0002	0.0002	0.0002	0.0000	0.0002	0.0002	0.0002	0.0000

NOTES: General All Avoided Costs are in Year 2017 Dollars
periods:

Table One: Avoided Cost of Electricity (2017 $) Results : RI Rhode Island

State RI

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	1.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate					DRIPE: 2017 vintage measures Intrastate					Avoided Non-Embedded Costs			
								Energy				Capacity (See note 2)	Energy				Capacity (See note 2)				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2017	0.0527	0.0464	0.0383	0.0296	130.7	*0.0*	65.4	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0483	0.0478	0.0515	0.0493
2018	0.0528	0.0462	0.0373	0.0297	212.6	*0.0*	106.3	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0480	0.0475	0.0512	0.0490
2019	0.0572	0.0508	0.0434	0.0358	145.3	*0.0*	72.6	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0476	0.0470	0.0507	0.0486
2020	0.0617	0.0534	0.0520	0.0397	104.2	*0.0*	52.1	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0471	0.0466	0.0502	0.0481
2021	0.0680	0.0596	0.0564	0.0446	111.3	145.9	128.6											0.0459	0.0454	0.0489	0.0468
2022	0.0691	0.0604	0.0581	0.0461	104.9	137.4	121.2											0.0446	0.0441	0.0476	0.0456
2023	0.0728	0.0635	0.0618	0.0499	98.6	129.1	113.9											0.0434	0.0429	0.0463	0.0443
2024	0.0753	0.0657	0.0641	0.0532	102.7	134.5	118.6											0.0422	0.0417	0.0449	0.0430
2025	0.0772	0.0678	0.0685	0.0550	113.2	148.2	130.7											0.0409	0.0404	0.0436	0.0418
2026	0.0767	0.0671	0.0697	0.0553	123.9	162.3	143.1											0.0397	0.0392	0.0423	0.0405
2027	0.0773	0.0676	0.0698	0.0557	134.2	175.8	155.0											0.0384	0.0380	0.0409	0.0392
2028	0.0784	0.0685	0.0736	0.0576	144.8	189.6	167.2											0.0372	0.0367	0.0396	0.0379
2029	0.0804	0.0707	0.0768	0.0597	156.1	204.5	180.3											0.0359	0.0355	0.0383	0.0367
2030	0.0817	0.0728	0.0785	0.0610	171.4	224.6	198.0											0.0347	0.0343	0.0369	0.0354
2031	0.0822	0.0738	0.0845	0.0626	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2032	0.0835	0.0754	0.0881	0.0643	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2033	0.0848	0.0770	0.0918	0.0661	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2034	0.0862	0.0787	0.0957	0.0680	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2035	0.0876	0.0804	0.0998	0.0699	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2036	0.0890	0.0822	0.1040	0.0719	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2037	0.0904	0.0840	0.1085	0.0740	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2038	0.0919	0.0858	0.1131	0.0761	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2039	0.0934	0.0877	0.1180	0.0782	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2040	0.0949	0.0896	0.1230	0.0805	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2041	0.0964	0.0916	0.1283	0.0828	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2042	0.0980	0.0936	0.1338	0.0851	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2043	0.0996	0.0956	0.1396	0.0876	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2044	0.1012	0.0977	0.1456	0.0901	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2045	0.1028	0.0999	0.1519	0.0927	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2046	0.1045	0.1021	0.1585	0.0954	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2047	0.1062	0.1043	0.1654	0.0981	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
Levelized Costs																					
10 years (2017-2026)	0.0660	0.0578	0.0545	0.0435	125.4	83.2	104.3	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.045	0.044	0.048	0.046
15 years (2017-2031)	0.0703	0.0618	0.0613	0.0484	135.1	121.0	128.1	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.042	0.042	0.045	0.043
30 years (2017-2046)	0.0806	0.0733	0.0870	0.0618	154.4	171.3	162.9	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.039	0.038	0.041	0.040

NOTES:

General All Avoided Costs are in Year 2017 Dollars

ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: RI

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2017	0.0433	0.0376	0.0302	0.0222			121.0	17.0%	0.0050	0.0012	0.0009	0.0068	0.0005	0.0012	0.0009	0.0068	0.0005
2018	0.0429	0.0369	0.0287	0.0218	0.0016	0.0010	196.9	17.2%	0.0055	0.0006	0.0005	0.0000	0.0000	0.0006	0.0005	0.0000	0.0000
2019	0.0466	0.0407	0.0339	0.0269	0.0010	0.0007	134.5	17.6%	0.0060	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2020	0.0509	0.0434	0.0420	0.0308	0.0010	0.0007	96.5	17.6%	0.0057	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2021	0.0556	0.0479	0.0449	0.0341	0.0002	0.0002	103.1	17.6%	0.0068								
2022	0.0569	0.0489	0.0467	0.0358	0.0002	0.0002	97.1	17.6%	0.0065								
2023	0.0607	0.0522	0.0506	0.0397	0.0002	0.0002	91.3	17.6%	0.0061								
2024	0.0634	0.0545	0.0531	0.0431	0.0002	0.0002	95.1	17.6%	0.0058								
2025	0.0655	0.0568	0.0574	0.0451	0.0002	0.0002	104.8	17.6%	0.0054								
2026	0.0654	0.0566	0.0589	0.0458	0.0002	0.0002	114.7	17.6%	0.0050								
2027	0.0664	0.0575	0.0595	0.0465	0.0002	0.0002	124.3	17.6%	0.0046								
2028	0.0677	0.0587	0.0633	0.0486	0.0002	0.0002	134.0	17.6%	0.0042								
2029	0.0692	0.0603	0.0659	0.0503	0.0002	0.0002	144.5	17.6%	0.0046								
2030	0.0707	0.0625	0.0678	0.0517	0.0002	0.0002	158.7	17.6%	0.0043								
2031	0.0711	0.0635	0.0733	0.0532	0.0002	0.0002	165.1	17.6%	0.0043								
2032	0.0723	0.0649	0.0766	0.0548	0.0002	0.0002	165.1	17.6%	0.0043								
2033	0.0736	0.0664	0.0800	0.0564	0.0002	0.0002	165.1	17.6%	0.0043								
2034	0.0748	0.0680	0.0836	0.0581	0.0002	0.0002	165.1	17.6%	0.0043								
2035	0.0761	0.0695	0.0873	0.0599	0.0002	0.0002	165.1	17.6%	0.0043								
2036	0.0774	0.0711	0.0912	0.0617	0.0002	0.0002	165.1	17.6%	0.0043								
2037	0.0787	0.0728	0.0953	0.0636	0.0002	0.0002	165.1	17.6%	0.0043								
2038	0.0801	0.0745	0.0995	0.0655	0.0002	0.0002	165.1	17.6%	0.0043								
2039	0.0814	0.0762	0.1040	0.0675	0.0002	0.0002	165.1	17.6%	0.0043								
2040	0.0828	0.0780	0.1086	0.0696	0.0002	0.0002	165.1	17.6%	0.0043								
2041	0.0842	0.0798	0.1135	0.0717	0.0002	0.0002	165.1	17.6%	0.0043								
2042	0.0856	0.0816	0.1185	0.0739	0.0002	0.0002	165.1	17.6%	0.0043								
2043	0.0871	0.0835	0.1238	0.0761	0.0002	0.0002	165.1	17.6%	0.0043								
2044	0.0886	0.0854	0.1294	0.0784	0.0002	0.0002	165.1	17.6%	0.0043								
2045	0.0901	0.0874	0.1351	0.0808	0.0002	0.0002	165.1	17.6%	0.0043								
2046	0.0916	0.0894	0.1412	0.0832	0.0002	0.0002	165.1	17.6%	0.0043								
2047	0.0932	0.0915	0.1475	0.0858	0.0002	0.0002	165.1	17.6%	0.0043								
Levelized Costs																	
10 years (2017-2026)	0.0548	0.0472	0.0442	0.0342	0.0005	0.0003	116.2	0.1749	0.0058	0.0002	0.0001	0.0007	0.0001	0.0002	0.0001	0.0007	0.0001
15 years (2017-2031)	0.0592	0.0513	0.0509	0.0391	0.0004	0.0003	125.1	0.1753	0.0053	0.0001	0.0001	0.0005	0.0000	0.0001	0.0001	0.0005	0.0000
30 years (2017-2046)	0.0691	0.0624	0.0749	0.0518	0.0003	0.0002	143.0	0.1756	0.0049	0.0001	0.0001	0.0003	0.0000	0.0001	0.0001	0.0003	0.0000

NOTES: General — All Avoided Costs are in Year 2017 Dollars
periods:

Table One: Avoided Cost of Electricity (2017 $) Results : VT Vermont

State VT

User-defined Inputs	
Wholesale Risk Premium (WRP)	9.00%
Distribution Losses	8.00%
Real Discount Rate	1.43%
Pcnt of Capacity Bid into FCM (%Bid)	50.00%

	Avoided Unit Cost of Electric Energy[1]				Avoided Unit Cost of Electric Capacity[2]			DRIPE: 2016 vintage measures Intrastate Energy				DRIPE: 2016 vintage measures Intrastate Capacity (See note 2)	DRIPE: 2017 vintage measures Intrastate Energy				DRIPE: 2017 vintage measures Intrastate Capacity (See note 2)	Avoided Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	kW sold into FCA (PA to determine quantity)[3]	kW purchased from FCA (PA to determine quantity)	Weighted Average Avoided Cost Based on Percent Capacity Bid	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Annual Value	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e=ab*1.08	f=ab*(1+ac)*(1+WRP)*(1+Dist Loss) *(1+PTF Loss)	g=(e*%Bid)+(f*(1+%Bid))	h	i	j	k	l	m	n	o	p	q	r	s	t	u
2017	0.0472	0.0410	0.0329	0.0242	130.7	*0.0*	65.4	0.0024	0.0010	0.0123	0.0009		0.0024	0.0010	0.0123	0.0009		0.0483	0.0478	0.0515	0.0493
2018	0.0468	0.0402	0.0313	0.0238	151.9	*0.0*	75.9	0.0013	0.0005	0.0000	0.0000		0.0013	0.0005	0.0000	0.0000		0.0480	0.0475	0.0512	0.0490
2019	0.0508	0.0443	0.0369	0.0293	101.9	*0.0*	50.9	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0476	0.0470	0.0507	0.0486
2020	0.0555	0.0473	0.0458	0.0336	104.2	*0.0*	52.1	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000		0.0471	0.0466	0.0502	0.0481
2021	0.0606	0.0522	0.0490	0.0372	111.3	145.9	128.6											0.0459	0.0454	0.0489	0.0468
2022	0.0620	0.0533	0.0510	0.0391	104.9	137.4	121.2											0.0446	0.0441	0.0476	0.0456
2023	0.0660	0.0567	0.0551	0.0432	98.6	129.1	113.9											0.0434	0.0429	0.0463	0.0443
2024	0.0689	0.0592	0.0577	0.0468	102.7	134.5	118.6											0.0422	0.0417	0.0449	0.0430
2025	0.0712	0.0618	0.0625	0.0490	113.2	148.2	130.7											0.0409	0.0404	0.0436	0.0418
2026	0.0711	0.0616	0.0641	0.0498	123.9	162.3	143.1											0.0397	0.0392	0.0423	0.0405
2027	0.0722	0.0625	0.0647	0.0505	134.2	175.8	155.0											0.0384	0.0380	0.0409	0.0392
2028	0.0736	0.0638	0.0690	0.0529	144.8	189.6	167.2											0.0372	0.0367	0.0396	0.0379
2029	0.0753	0.0656	0.0718	0.0547	156.1	204.5	180.3											0.0359	0.0355	0.0383	0.0367
2030	0.0770	0.0680	0.0738	0.0562	171.4	224.6	198.0											0.0347	0.0343	0.0369	0.0354
2031	0.0774	0.0690	0.0799	0.0578	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2032	0.0787	0.0706	0.0834	0.0596	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2033	0.0801	0.0723	0.0872	0.0614	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2034	0.0814	0.0740	0.0911	0.0632	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2035	0.0828	0.0757	0.0952	0.0652	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2036	0.0842	0.0774	0.0994	0.0671	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2037	0.0857	0.0792	0.1039	0.0692	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2038	0.0871	0.0811	0.1085	0.0713	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2039	0.0886	0.0829	0.1134	0.0735	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2040	0.0901	0.0848	0.1185	0.0757	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2041	0.0917	0.0868	0.1238	0.0780	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2042	0.0933	0.0888	0.1293	0.0804	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2043	0.0948	0.0909	0.1351	0.0828	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2044	0.0965	0.0930	0.1412	0.0853	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2045	0.0981	0.0951	0.1475	0.0879	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2046	0.0998	0.0973	0.1541	0.0906	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
2047	0.1015	0.0996	0.1610	0.0934	178.3	233.6	205.9											0.0347	0.0343	0.0369	0.0354
Levelized Costs																					
10 years (2017-2026)	0.0597	0.0514	0.0482	0.0372	114.6	83.2	98.9	0.0004	0.0002	0.0013	0.0001	0.0000	0.0004	0.0002	0.0013	0.0001	0.0000	0.045	0.044	0.048	0.046
15 years (2017-2031)	0.0644	0.0559	0.0555	0.0425	127.6	121.0	124.3	0.0003	0.0001	0.0009	0.0001	0.0000	0.0003	0.0001	0.0009	0.0001	0.0000	0.042	0.042	0.045	0.043
30 years (2017-2046)	0.0752	0.0679	0.0817	0.0564	150.3	171.3	160.8	0.0001	0.0001	0.0005	0.0000	0.0000	0.0001	0.0001	0.0005	0.0000	0.0000	0.039	0.038	0.041	0.040

NOTES:

General All Avoided Costs are in Year 2017 Dollars
ISO NE periods: Summer is June through September, Winter is all other months. Peak hours are: Monday through Friday 7 AM - 11 PM; Off-Peak Hours are all other hours

1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * risk premium, e.g. A = (v+ad) * (1+Wholesale Risk Premium)

2 Absolute value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA strategy re bidding that reduction into applicable FCAs, and unit values in columns e and f.

3 Proceeds from selling into the FCM also include the ISO-NE loss factor of 8%

4 PTF loss = 2.20%

5 Electric Cross -DRIPE is electric owen fuel DRIPE + Electric Cross-DRIPE

Table Two: Inputs to Avoided Cost Calculations

Zone: VT

	Wholesale Avoided Costs of Electricity								Avoided REC Costs to Load	DRIPE: 2016 vintage measures Rest-of-Pool				DRIPE: 2017 vintage measures Rest-of-Pool			
	Energy				Electric Cross DRIPE (5)		Capacity			Energy				Energy			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter	Summer	FCA Price	Reserve Margin	REC Costs	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	%	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh
Period:	v	w	x	y	z	aa	ab	ac	ad	ae	af	ag	ah	ai	aj	ak	al
2017	0.0433	0.0376	0.0302	0.0222			121.0	17.0%	0.0000	0.0016	0.0013	-0.0032	0.0007	0.0016	0.0013	-0.0032	0.0007
2018	0.0430	0.0369	0.0287	0.0218	0.0011	0.0007	140.6	17.2%	0.0000	0.0009	0.0007	0.0000	0.0000	0.0009	0.0007	0.0000	0.0000
2019	0.0466	0.0407	0.0339	0.0269	0.0007	0.0005	94.3	17.6%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2020	0.0509	0.0434	0.0421	0.0308	0.0007	0.0005	96.5	17.6%	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2021	0.0556	0.0479	0.0450	0.0342	0.0001	0.0001	103.1	17.6%	0.0000								
2022	0.0569	0.0489	0.0468	0.0358	0.0001	0.0001	97.1	17.6%	0.0000								
2023	0.0606	0.0521	0.0505	0.0396	0.0001	0.0001	91.3	17.6%	0.0000								
2024	0.0632	0.0543	0.0530	0.0429	0.0001	0.0001	95.1	17.6%	0.0000								
2025	0.0653	0.0567	0.0573	0.0449	0.0001	0.0001	104.8	17.6%	0.0000								
2026	0.0653	0.0565	0.0588	0.0457	0.0001	0.0001	114.7	17.6%	0.0000								
2027	0.0662	0.0573	0.0594	0.0464	0.0001	0.0001	124.3	17.6%	0.0000								
2028	0.0675	0.0585	0.0633	0.0485	0.0001	0.0001	134.0	17.6%	0.0000								
2029	0.0691	0.0602	0.0658	0.0501	0.0001	0.0001	144.5	17.6%	0.0000								
2030	0.0706	0.0624	0.0677	0.0516	0.0001	0.0001	158.7	17.6%	0.0000								
2031	0.0710	0.0633	0.0733	0.0530	0.0001	0.0001	165.1	17.6%	0.0000								
2032	0.0722	0.0648	0.0765	0.0546	0.0001	0.0001	165.1	17.6%	0.0000								
2033	0.0735	0.0663	0.0800	0.0563	0.0001	0.0001	165.1	17.6%	0.0000								
2034	0.0747	0.0679	0.0836	0.0580	0.0001	0.0001	165.1	17.6%	0.0000								
2035	0.0760	0.0694	0.0873	0.0598	0.0001	0.0001	165.1	17.6%	0.0000								
2036	0.0773	0.0710	0.0912	0.0616	0.0001	0.0001	165.1	17.6%	0.0000								
2037	0.0786	0.0727	0.0953	0.0635	0.0001	0.0001	165.1	17.6%	0.0000								
2038	0.0800	0.0744	0.0996	0.0654	0.0001	0.0001	165.1	17.6%	0.0000								
2039	0.0813	0.0761	0.1040	0.0674	0.0001	0.0001	165.1	17.6%	0.0000								
2040	0.0827	0.0778	0.1087	0.0694	0.0001	0.0001	165.1	17.6%	0.0000								
2041	0.0841	0.0796	0.1136	0.0716	0.0001	0.0001	165.1	17.6%	0.0000								
2042	0.0856	0.0815	0.1187	0.0737	0.0001	0.0001	165.1	17.6%	0.0000								
2043	0.0870	0.0834	0.1240	0.0760	0.0001	0.0001	165.1	17.6%	0.0000								
2044	0.0885	0.0853	0.1295	0.0783	0.0001	0.0001	165.1	17.6%	0.0000								
2045	0.0900	0.0873	0.1353	0.0807	0.0001	0.0001	165.1	17.6%	0.0000								
2046	0.0915	0.0893	0.1414	0.0831	0.0001	0.0001	165.1	17.6%	0.0000								
2047	0.0931	0.0914	0.1477	0.0857	0.0001	0.0001	165.1	17.6%	0.0000								
Levelized Costs																	
10 years (2017-2026)	0.0547	0.0472	0.0442	0.0341	0.0003	0.0002	106.1	0.1749	0.0000	0.0003	0.0002	-0.0003	0.0001	0.0003	0.0002	-0.0003	0.0001
15 years (2017-2031)	0.0591	0.0513	0.0509	0.0390	0.0002	0.0002	118.2	0.1753	0.0000	0.0002	0.0001	-0.0002	0.0000	0.0002	0.0001	-0.0002	0.0000
30 years (2017-2046)	0.0690	0.0623	0.0749	0.0517	0.0002	0.0001	139.1	0.1756	0.0000	0.0001	0.0001	-0.0001	0.0000	0.0001	0.0001	-0.0001	0.0000

NOTES: General — All Avoided Costs are in Year 2017 Dollars
periods:

AESC 2015 Update, Exhibit C-1
Avoided Cost of Gas to Retail Customers by End Use - Southern New England (CT, MA, RI)
Avoidable Retail Margin (2017$/MMBtu) - NONE

Year		RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
2017		3.87	4.55	4.77	4.60	4.12	4.56	4.37	4.49
2018		3.67	4.32	4.54	4.37	3.91	4.33	4.15	4.27
2019		4.43	4.96	5.14	5.00	4.63	4.98	4.82	4.92
2020		4.89	5.40	5.57	5.43	5.08	5.41	5.27	5.36
2021		5.40	5.92	6.10	5.96	5.60	5.94	5.78	5.88
2022		5.34	5.85	6.02	5.89	5.53	5.86	5.72	5.82
2023		5.69	6.20	6.38	6.23	5.89	6.21	6.07	6.16
2024		5.97	6.50	6.68	6.54	6.17	6.51	6.35	6.45
2025		6.10	6.61	6.79	6.64	6.30	6.62	6.48	6.57
2026		5.92	6.45	6.62	6.48	6.12	6.46	6.30	6.40
2027		5.83	6.35	6.53	6.39	6.03	6.36	6.21	6.31
2028		5.88	6.40	6.57	6.44	6.08	6.41	6.26	6.36
2029		5.94	6.45	6.62	6.49	6.13	6.46	6.32	6.41
2030		5.94	6.45	6.62	6.49	6.13	6.46	6.32	6.42
2031		5.89	6.41	6.58	6.45	6.09	6.41	6.27	6.37
2032		5.95	6.46	6.63	6.50	6.15	6.47	6.33	6.43
2033		6.01	6.52	6.69	6.56	6.20	6.53	6.39	6.49
2034		6.07	6.58	6.75	6.62	6.26	6.59	6.45	6.55
2035		6.13	6.64	6.81	6.68	6.32	6.65	6.51	6.61
2036		6.19	6.70	6.87	6.74	6.38	6.71	6.57	6.67
2037		6.25	6.76	6.93	6.80	6.45	6.77	6.63	6.73
2038		6.31	6.82	6.99	6.86	6.51	6.83	6.69	6.79
2039		6.38	6.89	7.06	6.93	6.57	6.89	6.75	6.85
2040		6.44	6.95	7.12	6.99	6.63	6.96	6.82	6.91
2041		6.50	7.01	7.18	7.05	6.70	7.02	6.88	6.98
2042		6.57	7.08	7.25	7.12	6.76	7.08	6.94	7.04
2043		6.63	7.14	7.31	7.18	6.83	7.15	7.01	7.11
2044		6.70	7.21	7.37	7.25	6.89	7.21	7.07	7.17
2045		6.77	7.27	7.44	7.31	6.96	7.28	7.14	7.24
2046		6.83	7.34	7.51	7.38	7.02	7.34	7.21	7.30
LEVELIZED									
2017-2026	(a)	5.10	5.65	5.83	5.68	5.30	5.66	5.50	5.60
2017-2031		5.34	5.88	6.06	5.92	5.55	5.89	5.74	5.84
2017-2046	(b)	5.80	6.33	6.50	6.37	6.00	6.34	6.19	6.29

(a) Real (constant $) riskless annual rate of return: 1.43%
(b) Values from 2032-2046 extrapolated from CAGR (2022-2031)

AESC 2015 Update, Exhibit C-2
Avoided Cost of Gas to Retail Customers by End Use - Southern New England (RI)
Avoidable Retail Margin (2017$/MMBtu) - SOME

		RESIDENTIAL				COMMERCIAL & INDUSTRIAL			
Year		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	ALL RETAIL END USES
2017		4.49	5.92	6.39	6.17	4.73	5.70	5.35	5.77
2018		4.29	5.69	6.16	5.94	4.52	5.48	5.13	5.54
2019		5.05	6.33	6.76	6.57	5.24	6.12	5.80	6.20
2020		5.51	6.77	7.19	7.01	5.70	6.55	6.25	6.63
2021		6.02	7.29	7.72	7.53	6.21	7.08	6.76	7.16
2022		5.95	7.22	7.64	7.46	6.15	7.00	6.70	7.09
2023		6.31	7.57	7.99	7.81	6.50	7.36	7.05	7.44
2024		6.59	7.87	8.30	8.11	6.78	7.65	7.33	7.73
2025		6.72	7.98	8.40	8.22	6.91	7.77	7.46	7.85
2026		6.54	7.81	8.24	8.05	6.73	7.60	7.28	7.68
2027		6.45	7.72	8.15	7.96	6.64	7.51	7.19	7.59
2028		6.50	7.77	8.19	8.01	6.69	7.55	7.24	7.64
2029		6.55	7.82	8.24	8.06	6.74	7.60	7.30	7.69
2030		6.56	7.82	8.24	8.07	6.75	7.60	7.30	7.69
2031		6.51	7.77	8.20	8.02	6.70	7.56	7.25	7.65
2032		6.57	7.83	8.25	8.08	6.76	7.61	7.31	7.70
2033		6.63	7.89	8.31	8.13	6.82	7.67	7.37	7.76
2034		6.68	7.95	8.37	8.19	6.88	7.73	7.43	7.82
2035		6.74	8.01	8.43	8.25	6.94	7.79	7.49	7.88
2036		6.80	8.07	8.49	8.31	7.00	7.85	7.55	7.94
2037		6.87	8.13	8.55	8.37	7.06	7.91	7.61	8.00
2038		6.93	8.19	8.61	8.43	7.12	7.97	7.67	8.06
2039		6.99	8.25	8.67	8.49	7.18	8.03	7.73	8.12
2040		7.05	8.31	8.73	8.55	7.24	8.09	7.79	8.18
2041		7.11	8.37	8.79	8.61	7.30	8.15	7.85	8.24
2042		7.18	8.43	8.85	8.68	7.37	8.22	7.91	8.31
2043		7.24	8.50	8.91	8.74	7.43	8.28	7.98	8.37
2044		7.31	8.56	8.98	8.80	7.50	8.34	8.04	8.43
2045		7.37	8.62	9.04	8.86	7.56	8.41	8.11	8.50
2046		7.44	8.69	9.10	8.93	7.63	8.47	8.17	8.56
LEVELIZED									
2017-2026	(a)	5.71	7.02	7.45	7.26	5.92	6.80	6.48	6.88
2017-2031		5.96	7.25	7.68	7.49	6.16	7.04	6.72	7.12
2017-2046	(b)	6.42	7.69	8.12	7.93	6.61	7.48	7.17	7.56

(a) Real (constant $) riskless annual rate of return: 1.43%
(b) Values from 2032-2046 extrapolated from CAGR (2022-2031)

AESC 2015 Update, Exhibit C-3
Avoided Cost of Gas, Retail Customers by End Use - Northern New England (NH, ME)
Avoidable Retail Margin (2017$/MMBtu) - NONE

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
2017	4.22	4.69	4.85	4.73	4.39	4.70	4.57	4.65
2018	3.82	4.62	4.89	4.68	4.13	4.64	4.41	4.55
2019	4.40	6.40	7.06	6.53	5.15	6.43	5.87	6.23
2020	4.85	6.84	7.50	6.97	5.59	6.87	6.30	6.66
2021	5.35	7.38	8.06	7.51	6.11	7.41	6.85	7.21
2022	5.29	7.33	8.01	7.47	6.05	7.36	6.79	7.15
2023	5.64	7.68	8.37	7.82	6.40	7.71	7.14	7.51
2024	5.92	8.01	8.70	8.15	6.70	8.04	7.45	7.82
2025	6.04	8.12	8.82	8.26	6.82	8.16	7.57	7.94
2026	5.86	7.97	8.68	8.11	6.64	8.00	7.40	7.78
2027	5.78	7.89	8.59	8.04	6.57	7.92	7.33	7.71
2028	5.82	7.94	8.65	8.08	6.61	7.97	7.37	7.75
2029	5.87	7.99	8.70	8.13	6.66	8.02	7.43	7.81
2030	5.87	7.99	8.70	8.14	6.67	8.03	7.43	7.81
2031	5.83	7.95	8.65	8.09	6.62	7.98	7.38	7.76
2032	5.88	8.01	8.72	8.15	6.68	8.04	7.44	7.83
2033	5.94	8.08	8.79	8.22	6.74	8.11	7.50	7.89
2034	6.00	8.14	8.86	8.28	6.80	8.18	7.57	7.95
2035	6.05	8.21	8.92	8.35	6.86	8.24	7.63	8.02
2036	6.11	8.27	8.99	8.42	6.92	8.31	7.69	8.09
2037	6.17	8.34	9.06	8.48	6.98	8.38	7.76	8.15
2038	6.23	8.41	9.13	8.55	7.05	8.44	7.82	8.22
2039	6.29	8.47	9.20	8.62	7.11	8.51	7.89	8.29
2040	6.35	8.54	9.27	8.69	7.17	8.58	7.95	8.35
2041	6.41	8.61	9.35	8.76	7.24	8.65	8.02	8.42
2042	6.47	8.68	9.42	8.83	7.30	8.72	8.09	8.49
2043	6.54	8.75	9.49	8.90	7.37	8.79	8.15	8.56
2044	6.60	8.82	9.56	8.97	7.43	8.86	8.22	8.63
2045	6.66	8.89	9.64	9.04	7.50	8.94	8.29	8.70
2046	6.73	8.97	9.71	9.12	7.57	9.01	8.36	8.77

LEVELIZED

2017-2026	(a)	$ 5.11	$ 6.86	$ 7.44	$ 6.98	$ 5.76	$ 6.89	$ 6.39	$ 6.71
2017-2031		$ 5.33	$ 7.20	$ 7.82	$ 7.32	$ 6.03	$ 7.23	$ 6.70	$ 7.04
2017-2046	(b)	$ 5.76	$ 7.76	$ 8.43	$ 7.90	$ 6.51	$ 7.80	$ 7.23	$ 7.59

(a) Real (constant $) riskless annual rate of return: 1.43%
(b) Values from 2032-2046 extrapolated from CAGR (2022-2031)

AESC 2015 Update, Exhibit C-4
Avoided Cost of Gas, Retail Customers by End Use - Northern New England (NH, ME)
Avoidable Retail Margin (2017$/MMBtu) - SOME

Year		RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
2017		4.75	5.86	6.23	6.08	4.87	5.59	5.34	5.46
2018		4.35	5.79	6.27	6.02	4.61	5.53	5.18	5.36
2019		4.93	7.57	8.45	7.88	5.63	7.33	6.64	7.04
2020		5.37	8.01	8.88	8.31	6.06	7.76	7.07	7.47
2021		5.88	8.55	9.44	8.86	6.59	8.31	7.62	8.02
2022		5.82	8.50	9.40	8.81	6.53	8.25	7.56	7.96
2023		6.16	8.85	9.75	9.17	6.88	8.61	7.90	8.31
2024		6.45	9.18	10.09	9.49	7.18	8.93	8.22	8.63
2025		6.56	9.29	10.20	9.61	7.30	9.05	8.34	8.75
2026		6.39	9.14	10.06	9.45	7.12	8.90	8.17	8.59
2027		6.30	9.06	9.98	9.38	7.05	8.81	8.10	8.52
2028		6.35	9.11	10.03	9.42	7.09	8.87	8.14	8.56
2029		6.40	9.16	10.08	9.48	7.14	8.92	8.19	8.61
2030		6.40	9.16	10.08	9.48	7.15	8.92	8.20	8.62
2031		6.35	9.12	10.04	9.43	7.10	8.87	8.15	8.57
2032		6.41	9.18	10.10	9.50	7.16	8.94	8.21	8.63
2033		6.47	9.24	10.17	9.56	7.22	9.00	8.27	8.70
2034		6.52	9.31	10.24	9.63	7.28	9.07	8.33	8.76
2035		6.58	9.37	10.31	9.69	7.34	9.14	8.40	8.83
2036		6.64	9.44	10.37	9.76	7.40	9.20	8.46	8.89
2037		6.70	9.51	10.44	9.82	7.46	9.27	8.52	8.96
2038		6.76	9.57	10.51	9.89	7.52	9.34	8.59	9.02
2039		6.81	9.64	10.58	9.96	7.59	9.40	8.65	9.09
2040		6.87	9.71	10.65	10.03	7.65	9.47	8.72	9.16
2041		6.93	9.77	10.72	10.10	7.71	9.54	8.78	9.23
2042		7.00	9.84	10.79	10.16	7.78	9.61	8.85	9.29
2043		7.06	9.91	10.87	10.23	7.84	9.68	8.91	9.36
2044		7.12	9.98	10.94	10.30	7.91	9.75	8.98	9.43
2045		7.18	10.05	11.01	10.37	7.97	9.82	9.05	9.50
2046		7.25	10.12	11.08	10.44	8.04	9.89	9.12	9.57
LEVELIZED									
2016-2025	(a)	5.64	8.03	8.83	8.32	6.24	7.78	7.16	7.51
2016-2030		5.86	8.37	9.20	8.67	6.51	8.12	7.47	7.84
2016-2045	(b)	6.28	8.93	9.81	9.24	6.99	8.69	7.99	8.40

(a) Real (constant $) riskless annual rate of return: 1.43%
(b) Values from 2032-2046 extrapolated from CAGR (2022-2031)

AESC 2015 Update, Exhibit C-5
Avoided Cost of Gas by Retail End Use - Vermont (VT)
Avoidable Retail Margin (2017$/MMBtu) - NONE

		Design day	Peak Days	Remaining winter	Shoulder / summer
Year	Days	1	9	141	214
2017		$ 536.59	$ 14.01	$ 5.53	$ 4.19
2018		$ 536.34	$ 14.53	$ 4.91	$ 3.94
2019		$ 536.88	$ 16.59	$ 5.89	$ 4.48
2020		$ 537.39	$ 18.65	$ 6.34	$ 4.99
2021		$ 537.90	$ 20.71	$ 6.91	$ 5.50
2022		$ 537.92	$ 22.77	$ 6.91	$ 5.52
2023		$ 538.32	$ 24.83	$ 7.30	$ 5.93
2024		$ 538.59	$ 25.37	$ 7.60	$ 6.19
2025		$ 538.72	$ 26.08	$ 7.72	$ 6.32
2026		$ 538.58	$ 26.96	$ 7.60	$ 6.18
2027		$ 538.54	$ 27.72	$ 7.55	$ 6.14
2028		$ 538.59	$ 28.35	$ 7.60	$ 6.20
2029		$ 538.64	$ 29.07	$ 7.66	$ 6.25
2030		$ 538.65	$ 29.60	$ 7.66	$ 6.25
2031		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2032		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2033		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2034		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2035		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2036		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2037		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2038		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2039		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2040		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2041		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2042		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2043		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2044		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2045		$ 538.60	$ 30.58	$ 7.61	$ 6.20
2046		$ 538.60	$ 30.58	$ 7.61	$ 6.20
LEVELIZED					
2017-2026	(a)	$537.69	$20.86	$6.64	$5.29
2017-2031		$537.97	$23.40	$6.94	$5.58
2017-2046	(b)	$538.25	$26.61	$7.24	$5.86

(a) Real discount rate: 1.43%
(b) Values from 2032-2046 extrapolated from CAGR (2022-2031)

AESC 2015 Update Exhibit D - 1

Avoided Costs of Petroleum and Other Fuels by Sector (2017$/MMBtu)

Year	Fuel Oils							Other Fuels				
	Residential	Commercial			Industrial			Residential				Industrial
	Distillate Fuel Oil	Distillate Fuel Oil	Residual Fuel	Weighted Average	Distillate Fuel Oil	Residual Fuel Oil	Weighted Average	Cord Wood	Wood Pellets	Kerosene	Propane	Kerosene
	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$
2017	$ 12.66	$ 11.74	$ 10.49	$ 11.57	$ 11.60	$ 10.49	$ 11.31	N/A	N/A	$ 13.81	$ 12.40	$ 11.60
2018	$ 13.07	$ 12.14	$ 10.80	$ 11.96	$ 12.01	$ 10.80	$ 11.70	N/A	N/A	$ 14.26	$ 12.92	$ 12.01
2019	$ 14.86	$ 13.84	$ 12.20	$ 13.61	$ 13.71	$ 12.20	$ 13.32	N/A	N/A	$ 16.21	$ 14.53	$ 13.71
2020	$ 16.62	$ 15.50	$ 13.64	$ 15.24	$ 15.34	$ 13.64	$ 14.90	N/A	N/A	$ 18.13	$ 16.05	$ 15.34
2021	$ 18.33	$ 17.13	$ 15.00	$ 16.83	$ 16.97	$ 15.00	$ 16.46	N/A	N/A	$ 20.00	$ 17.57	$ 16.97
2022	$ 20.03	$ 18.76	$ 16.50	$ 18.44	$ 18.61	$ 16.50	$ 18.06	N/A	N/A	$ 21.85	$ 19.00	$ 18.61
2023	$ 21.66	$ 20.28	$ 17.79	$ 19.93	$ 20.09	$ 17.79	$ 19.50	N/A	N/A	$ 23.62	$ 20.31	$ 20.09
2024	$ 21.98	$ 20.56	$ 17.97	$ 20.20	$ 20.35	$ 17.97	$ 19.73	N/A	N/A	$ 23.98	$ 20.43	$ 20.35
2025	$ 22.46	$ 21.04	$ 18.30	$ 20.65	$ 20.83	$ 18.30	$ 20.17	N/A	N/A	$ 24.50	$ 20.74	$ 20.83
2026	$ 23.06	$ 21.63	$ 18.96	$ 21.26	$ 21.42	$ 18.96	$ 20.78	N/A	N/A	$ 25.16	$ 21.23	$ 21.42
2027	$ 23.57	$ 22.13	$ 19.44	$ 21.75	$ 21.92	$ 19.44	$ 21.27	N/A	N/A	$ 25.72	$ 21.52	$ 21.92
2028	$ 23.93	$ 22.46	$ 19.65	$ 22.07	$ 22.24	$ 19.65	$ 21.57	N/A	N/A	$ 26.10	$ 21.76	$ 22.24
2029	$ 24.41	$ 22.93	$ 20.24	$ 22.55	$ 22.70	$ 20.24	$ 22.06	N/A	N/A	$ 26.63	$ 22.07	$ 22.70
2030	$ 24.75	$ 23.27	$ 20.54	$ 22.88	$ 23.04	$ 20.54	$ 22.39	N/A	N/A	$ 27.00	$ 22.30	$ 23.04
2031	$ 25.57	$ 24.04	$ 21.22	$ 23.65	$ 23.81	$ 21.22	$ 23.14	N/A	N/A	$ 27.89	$ 23.04	$ 23.81
2032	$ 26.20	$ 24.64	$ 21.76	$ 24.24	$ 24.40	$ 21.76	$ 23.72	N/A	N/A	$ 28.58	$ 23.49	$ 24.40
2033	$ 26.85	$ 25.26	$ 22.32	$ 24.85	$ 25.01	$ 22.32	$ 24.31	N/A	N/A	$ 29.29	$ 23.95	$ 25.01
2034	$ 27.51	$ 25.90	$ 22.89	$ 25.47	$ 25.64	$ 22.89	$ 24.92	N/A	N/A	$ 30.01	$ 24.41	$ 25.64
2035	$ 28.19	$ 26.55	$ 23.47	$ 26.12	$ 26.28	$ 23.47	$ 25.55	N/A	N/A	$ 30.75	$ 24.89	$ 26.28
2036	$ 28.89	$ 27.21	$ 24.07	$ 26.77	$ 26.93	$ 24.07	$ 26.19	N/A	N/A	$ 31.51	$ 25.38	$ 26.93
2037	$ 29.60	$ 27.90	$ 24.68	$ 27.45	$ 27.61	$ 24.68	$ 26.84	N/A	N/A	$ 32.29	$ 25.87	$ 27.61
2038	$ 30.33	$ 28.60	$ 25.31	$ 28.14	$ 28.29	$ 25.31	$ 27.52	N/A	N/A	$ 33.09	$ 26.37	$ 28.29
2039	$ 31.08	$ 29.31	$ 25.96	$ 28.84	$ 29.00	$ 25.96	$ 28.21	N/A	N/A	$ 33.91	$ 26.89	$ 29.00
2040	$ 31.85	$ 30.05	$ 26.62	$ 29.57	$ 29.72	$ 26.62	$ 28.92	N/A	N/A	$ 34.74	$ 27.41	$ 29.72
2041	$ 32.64	$ 30.80	$ 27.30	$ 30.31	$ 30.47	$ 27.30	$ 29.64	N/A	N/A	$ 35.60	$ 27.95	$ 30.47
2042	$ 33.44	$ 31.58	$ 27.99	$ 31.07	$ 31.23	$ 27.99	$ 30.38	N/A	N/A	$ 36.48	$ 28.49	$ 31.23
2043	$ 34.27	$ 32.37	$ 28.71	$ 31.86	$ 32.01	$ 28.71	$ 31.15	N/A	N/A	$ 37.38	$ 29.04	$ 32.01
2044	$ 35.11	$ 33.18	$ 29.44	$ 32.66	$ 32.80	$ 29.44	$ 31.93	N/A	N/A	$ 38.30	$ 29.61	$ 32.80
2045	$ 35.98	$ 34.01	$ 30.19	$ 33.48	$ 33.62	$ 30.19	$ 32.73	N/A	N/A	$ 39.25	$ 30.19	$ 33.62
2046	$ 36.87	$ 34.87	$ 30.96	$ 34.32	$ 34.46	$ 30.96	$ 33.55	N/A	N/A	$ 40.22	$ 30.78	$ 34.46
Levelized Costs												
2017-2026	$18.32	$17.12	$15.04	$16.83	$16.95	$15.04	$16.46	N/A	N/A	$19.99	$17.39	$16.95
2017-2031	$20.22	$18.93	$16.64	$18.61	$18.74	$16.64	$18.20	N/A	N/A	$22.05	$18.86	$18.74
2017-2046	$25.06	$23.56	$20.80	$23.17	$23.32	$20.80	$22.66	N/A	N/A	$27.34	$22.43	$23.32

Notes

2032-2046 costs extrapolated based on 2022-2031 compound annual growth rate

Real discount rate 1.43%

AESC 2015 Update Exhibit D - 2

Crude Oil and Fuel Prices by Sector in New England (2017$/MMBtu)

	Crude Oil Prices				Electric Generation		Residential			Commercial			Industrial		
Year	AEO 2014 Reference case WTI	WTI NYMEX Futures, 9-27-2016	AESC 2015 Update Forecast WTI		Distillate Fuel Oil	Residual Fuel Oil	Distillate Fuel Oil	Kerosene	Cord Wood	Distillate Fuel Oil	Residual Fuel	Kerosene	Distillate Fuel Oil	Residual Fuel Oil	Kerosene
	$/MMBtu	$/MMBtu	$/MMBtu	$/BBl	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$	2017$
2017	$ 8.62	$ 8.29	$ 8.29	$ 48.07	$ 13.07	8.78	$ 12.66	$ 13.81	N/A	$ 11.74	$ 10.49	$ 13.81	$ 11.60	$ 10.49	$ 11.60
2018	$ 9.25	$ 8.59	$ 8.59	$ 49.84	$ 14.35	9.87	$ 13.07	$ 14.26	N/A	$ 12.14	$ 10.80	$ 14.26	$ 12.01	$ 10.80	$ 12.01
2019	$ 11.55	$ 8.70	$ 9.81	$ 56.91	$ 15.24	11.33	$ 14.86	$ 16.21	N/A	$ 13.84	$ 12.20	$ 16.21	$ 13.71	$ 12.20	$ 13.71
2020	$ 12.81	$ 8.77	$ 11.03	$ 63.98	$ 16.51	12.37	$ 16.62	$ 18.13	N/A	$ 15.50	$ 13.64	$ 18.13	$ 15.34	$ 13.64	$ 15.34
2021	$ 13.63	$ 8.79	$ 12.25	$ 71.06	$ 18.11	13.64	$ 18.33	$ 20.00	N/A	$ 17.13	$ 15.00	$ 20.00	$ 16.97	$ 15.00	$ 16.97
2022	$ 14.27	$ 8.78	$ 13.47	$ 78.13	$ 19.72	14.95	$ 20.03	$ 21.85	N/A	$ 18.76	$ 16.50	$ 21.85	$ 18.61	$ 16.50	$ 18.61
2023	$ 14.69	$ 8.74	$ 14.69	$ 85.20	$ 21.32	16.26	$ 21.66	$ 23.62	N/A	$ 20.28	$ 17.79	$ 23.62	$ 20.09	$ 17.79	$ 20.09
2024	$ 15.01	$ 8.65	$ 15.01	$ 87.05	$ 21.69	16.58	$ 21.98	$ 23.98	N/A	$ 20.56	$ 17.97	$ 23.98	$ 20.35	$ 17.97	$ 20.35
2025	$ 15.43	$ -	$ 15.43	$ 89.49	$ 22.13	17.00	$ 22.46	$ 24.50	N/A	$ 21.04	$ 18.30	$ 24.50	$ 20.83	$ 18.30	$ 20.83
2026	$ 15.95	$ -	$ 15.95	$ 92.50	$ 22.69	17.56	$ 23.06	$ 25.16	N/A	$ 21.63	$ 18.96	$ 25.16	$ 21.42	$ 18.96	$ 21.42
2027	$ 16.40	$ -	$ 16.40	$ 95.12	$ 23.17	17.93	$ 23.57	$ 25.72	N/A	$ 22.13	$ 19.44	$ 25.72	$ 21.92	$ 19.44	$ 21.92
2028	$ 16.77	$ -	$ 16.77	$ 97.27	$ 23.55	18.19	$ 23.93	$ 26.10	N/A	$ 22.46	$ 19.65	$ 26.10	$ 22.24	$ 19.65	$ 22.24
2029	$ 17.20	$ -	$ 17.20	$ 99.75	$ 24.09	18.59	$ 24.41	$ 26.63	N/A	$ 22.93	$ 20.24	$ 26.63	$ 22.70	$ 20.24	$ 22.70
2030	$ 17.51	$ -	$ 17.51	$ 101.56	$ 24.47	18.85	$ 24.75	$ 27.00	N/A	$ 23.27	$ 20.54	$ 27.00	$ 23.04	$ 20.54	$ 23.04
2031	$ 18.09	$ -	$ 18.09	$ 104.94	$ 25.01	19.32	$ 25.57	$ 27.89	N/A	$ 24.04	$ 21.22	$ 27.89	$ 23.81	$ 21.22	$ 23.81
Levelized Costs															
2017-2026	$13.03	$7.03	$12.34	$71.58	$18.35	$13.71	$18.32	$19.99	N/A	$17.12	$15.04	$19.99	$16.95	$15.04	$16.95
2017-2031	$14.31	$4.85	$13.84	$80.29	$20.12	$15.22	$20.22	$22.05	N/A	$18.93	$16.64	$22.05	$18.74	$16.64	$18.74
Notes															
Real discount rate	1.43%														

AESC 2015 Update Exhibit D - 3

Fuel Oil Emission Values (2017$/MMBtu)

Year	Residential				Commercial				Industrial			
	SO2	NOx	CO2	CO2 at $100/ton	SO2	NOx	CO2	CO2 at $100/ton	SO2	NOx	CO2	CO2 at $100/ton
2017	$ 0.000	$ 0.000	$ 0.528	$ 8.407	$ 0.000	$ 0.000	$ 0.527	$ 8.396	$ 0.000	$ 0.000	$ 0.528	$ 8.399
2018	$ 0.000	$ 0.000	$ 0.610	$ 8.407	$ 0.000	$ 0.000	$ 0.609	$ 8.396	$ 0.000	$ 0.000	$ 0.610	$ 8.399
2019	$ 0.000	$ 0.000	$ 0.661	$ 8.407	$ 0.000	$ 0.000	$ 0.660	$ 8.396	$ 0.000	$ 0.000	$ 0.661	$ 8.399
2020	$ 0.000	$ 0.000	$ 0.712	$ 8.407	$ 0.000	$ 0.000	$ 0.711	$ 8.396	$ 0.000	$ 0.000	$ 0.712	$ 8.399
2021	$ 0.000	$ 0.000	$ 0.783	$ 8.407	$ 0.000	$ 0.000	$ 0.782	$ 8.396	$ 0.000	$ 0.000	$ 0.783	$ 8.399
2022	$ 0.000	$ 0.000	$ 0.855	$ 8.407	$ 0.000	$ 0.000	$ 0.853	$ 8.396	$ 0.000	$ 0.000	$ 0.854	$ 8.399
2023	$ 0.000	$ 0.000	$ 1.054	$ 8.407	$ 0.000	$ 0.000	$ 1.053	$ 8.396	$ 0.000	$ 0.000	$ 1.053	$ 8.399
2024	$ 0.000	$ 0.000	$ 1.254	$ 8.407	$ 0.000	$ 0.000	$ 1.253	$ 8.396	$ 0.000	$ 0.000	$ 1.253	$ 8.399
2025	$ 0.000	$ 0.000	$ 1.454	$ 8.407	$ 0.000	$ 0.000	$ 1.452	$ 8.396	$ 0.000	$ 0.000	$ 1.453	$ 8.399
2026	$ 0.000	$ 0.000	$ 1.654	$ 8.407	$ 0.000	$ 0.000	$ 1.652	$ 8.396	$ 0.000	$ 0.000	$ 1.652	$ 8.399
2027	$ 0.000	$ 0.000	$ 1.854	$ 8.407	$ 0.000	$ 0.000	$ 1.851	$ 8.396	$ 0.000	$ 0.000	$ 1.852	$ 8.399
2028	$ 0.000	$ 0.000	$ 2.054	$ 8.407	$ 0.000	$ 0.000	$ 2.051	$ 8.396	$ 0.000	$ 0.000	$ 2.052	$ 8.399
2029	$ 0.000	$ 0.000	$ 2.253	$ 8.407	$ 0.000	$ 0.000	$ 2.250	$ 8.396	$ 0.000	$ 0.000	$ 2.251	$ 8.399
2030	$ 0.000	$ 0.000	$ 2.453	$ 8.407	$ 0.000	$ 0.000	$ 2.450	$ 8.396	$ 0.000	$ 0.000	$ 2.451	$ 8.399
2031	$ 0.000	$ 0.000	$ 2.453	$ 8.407	$ 0.000	$ 0.000	$ 2.450	$ 8.396	$ 0.000	$ 0.000	$ 2.451	$ 8.399
Levelized Costs												
2017-2026	$0.00	$0.00	$0.94	$8.41	$0.00	$0.00	$0.94	$8.40	$0.00	$0.00	$0.94	$8.40
2017-2031	$0.00	$0.00	$1.34	$8.41	$0.00	$0.00	$1.33	$8.40	$0.00	$0.00	$1.33	$8.40

Notes

Real Discount rate	1.43%