Avoided Energy Supply Components in New England: 2018 Report

Prepared for AESC 2018 Study Group

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List of Acronyms

AESC	Avoided energy supply component / cost
AEO	Annual Energy Outlook
Bcf	Billion cubic feet
CAGR	Compound annual growth rate
CEC	Clean Energy Certificate
CES	Clean Energy Standard
CCS	Carbon capture and sequestration
DOER	Massachusetts Department of Energy Resources
DRIPE	Demand Reduction Induced Price Effects
EIA	Energy Information Administration
FCA	Forward capacity auction
FCM	Forward capacity market
GWSA	Global Warming Solutions Act
HDD	Heating Degree Day
IPCC	Intergovernmental Panel on Climate Change
ISO	Independent system operator
LNG	Liquefied Natural Gas
LSE	Load-Serving Entity
MMcf	Million Cubic Feet
PTF	Pool transmission facilities
REC	Renewable Energy Certificate
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard

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1. EXECUTIVE SUMMARY

This document is the 2018 Avoided Energy Supply Component (AESC) Study (2018 AESC or AESC 2018). It contains projections of marginal energy supply components that can be avoided in future years due to reductions in the use of electricity, natural gas, and other fuels as a result of program-based energy efficiency or other demand-side measures across all six New England states.

The 2018 AESC Study provides estimates of avoided costs associated with energy efficiency measures for program administrators (PAs) throughout New England states for purposes of both internal decision-making and regulatory filings. To determine the values of energy efficiency (and other demand-side measures), avoided costs are calculated and provided for each New England state in a hypothetical future in which **no new** energy efficiency measures are installed in 2018 or later years.

Because the "main" AESC case represents a theoretical future in which no new energy efficiency measures are put into place, 2018 AESC should <u>not</u> be used to infer information about actual future market conditions, energy prices, or resource builds in New England. Furthermore, actual prices in the future will be different than the long-term prices calculated in this study as actual future prices will be subject to short-term variations in energy markets that are unknowable at this point in time. Note also that these caveats may also apply to sensitives modeled in the 2018 AESC study (see Chapter 12 for more information).

As in previous AESC studies, this study examines avoided costs of energy, capacity, natural gas, fuel oil, other fuels, other environmental costs, and demand reduction induced price effects (DRIPE). As in previous studies, the 2018 study relies on a combination of models to estimate each one of these costs for each future year. New to AESC 2018, we calculate avoided energy costs on an hourly basis. This will allow users of the report to estimate avoided costs specific to a broad array of active demand response programs, including active load management and peak load shifting programs.

On a 15-year levelized basis, the 2018 AESC study estimates that direct avoided retail energy costs are approximately 7 cents per kWh, and direct avoided gas costs are $6 to $8 per MMBtu, depending on the specific location and end-use. Compared to the previous 2015 AESC study, we find:

- Generally lower avoided costs of energy, due to sustained low natural gas prices at national hubs, and lower estimated costs of complying with the Regional Greenhouse Gas Initiative (RGGI).
- Generally lower avoided costs of capacity, due to changes in market rules, and a lower estimate for the cost of new entry (CONE).
- Generally lower avoided costs of natural gas excluding avoidable margins, based on adjustments to underlying assumptions regarding shale gas breakeven prices

and operating costs, which decrease short-term and long-term projections of natural gas prices. We also find different avoided gas costs for retail end users than in AESC 2015, based on updated assumptions on incremental gas pipeline expansion costs and changes to the location of marginal gas resources.

- Generally higher avoided costs for fuel oil and other fuels, due to a change in the sources being used to calculate these values.

- Generally lower avoided costs for renewable portfolio standard (RPS) compliance, associated with supply additions in the near term combined with new policies which drive long-term increases in renewables without corresponding increases in renewable energy certificate (REC) demand.

- Higher energy DRIPE values, but lower natural gas DRIPE values. We also estimated values for electric capacity DRIPE and oil DRIPE, where these were estimated to be non-existent or were not calculated in AESC 2015.

- Generally similar non-embedded costs for environmental regulations that are not otherwise included in the above projections (e.g., CO_2 and NO_X). As in previous studies, these costs are primarily based on the cost of the marginal abatement resource.

New to 2018 AESC is the addition of two new chapters: one addressing the avoided costs of transmission and distribution (T&D) and one addressing the value of reliability. For these topics, we find the following:

- For the new T&D section, we developed a standardized approach to estimating generic avoidable transmission and distribution costs. Based on a review of literature from ISO New England and the utilities, we estimate a $/kW cost for pool transmission facilities (PTF) costs and provide a discussion of methods on how to calculate non-PTF costs. The addition of a PTF avoided cost for the first time in an AESC study results in higher T&D avoided costs compared to AESC 2015.

- For the new reliability section, we conducted a literature review of the value of lost load, estimated the value of generation reliability due to lower loads and higher reserve margins, and conducted a review of the available data on transmission and distribution outages—including whether the effect of load on outage rates can be determined from this data. AESC 2018 finds that the 15-year levelized benefit of increasing generation reserves through reduced energy usage is $0.65/kW-year for cleared resources and $6.60/kW-year for uncleared load reductions.

This report provides detailed projections of avoided costs by year for an initial period based on modeling (2018 through 2035), and a second period based on extrapolation of values in this first period (2036 through 2050).[1] All values in this document are described in terms of real 2018 dollars, unless noted otherwise. In many cases, we provide 15-year (2018–2032) levelized values of avoided costs for ease of reporting and comparison with earlier AESC studies. See *Appendix E. Financial Parameters* for more information on financial parameters used in this analysis.

1.1. Background to the AESC Study

As in previous AESC studies, the 2018 AESC Study was sponsored by a group of electric and gas utilities and other efficiency program administrators (together, referred to as program administrators). The study sponsors, along with other parties (including representatives from state governments, consumer advocacy organizations, and environmental advocacy organizations and their consultants) formed a Study Group to oversee the design and production of the analysis and report.

Study sponsors for the 2018 AESC Study include: Berkshire Gas Company, Cape Light Compact, Liberty Utilities, National Grid USA, Eversource (Connecticut Light and Power, NSTAR Electric and Gas Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and Yankee Gas), New Hampshire Electric Co-op, Columbia Gas of Massachusetts, Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc. and Northern Utilities), United Illuminating, Southern Connecticut Gas and Connecticut Natural Gas, Efficiency Maine, and the State of Vermont. Other parties represented in the Study Group include: Connecticut Department of Energy and Environmental Protection, Connecticut Energy Efficiency Board, Massachusetts Energy Efficiency Advisory Council, Massachusetts Department of Public Utilities, Massachusetts Department of Energy Resources, Massachusetts Attorney General, Massachusetts Low-Income Energy Affordability Network (LEAN), Environment Northeast, Conservation Law Foundation, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Rhode Island Energy Efficiency and Resource Management Council, and Vermont Department of Public Service.

After developing the scope to the 2018 Study, the study sponsors selected Synapse Energy Economics (Synapse) as the lead contractor of the study. Synapse was joined by subcontractors Resource Insight, Sustainable Energy Advantage, Les Deman Consulting, and North Side Energy (together, the Analysis Team).

1.2. Summary of Avoided Costs

The following section provides a summary of the avoided costs for each category of costs calculated under the 2018 AESC study. These categories include costs that can be applied to energy efficiency measures that avoid electricity (energy, capacity, DRIPE, RPS, etc.), while others are related to energy efficiency measures that avoid other types of energy consumption. ES-Table 1 provides an illustration of

[1] This extrapolation is based on cumulative average growth rates, which span differing time periods depending on the specific type avoided cost; these periods are noted throughout the text.

summer on-peak avoided cost components for electricity for the WCMA zone, and how these components compare to the values from the previous AESC 2015 study.[2] ES-Table 2 performs the same comparison for the AESC 2015 Update, released in 2016. Note that in ES-Table 2, we compare the AESC 2018 WCMA values against average New England values from the AESC 2015 Update, as Massachusetts and Connecticut did not take part in the AESC 2015 Update.

In general, we find that low wholesale natural gas prices drive lower avoided energy costs, relative to AESC 2015 (despite changes to pipeline capacity costs assumptions that push avoided retail natural gas costs up, relative to AESC 2015). We find that higher renewable supply additions in the near term and new policies which drive long-term increases in renewables result in lower avoided RPS costs, due in part to a lack of corresponding increases in REC demand. We find that changes to methodologies and input assumptions result in lower avoided capacity prices, but higher DRIPE values.

Note that comparisons between 15-year levelized costs in AESC 2018 and AESC 2015 are not directly "apples-to-apples." While both calculations levelized costs over 15 years, each levelization calculation is done over two different 15-year periods (2016 to 2030 for AESC 2015, and 2018 to 2032 for AESC 2018). Assumptions on prices and loads aside, the time periods spanned by each of these levelization calculations may contain fundamentally different data on the New England electric system, including differences in terms of online units and market rules.

[2] Table ES-1 and ES-Table 2 present information consistent with previous AESC reports for informational purposes.

ES-Table 1. Illustration of avoided retail summer on-peak electricity cost components, AESC 2018 versus AESC 2015

	AESC 2015 *2015 cents/kWh*	AESC 2015 *2018 cents/kWh*	AESC 2018 *2018 cents/kWh*	AESC 2018, relative to AESC 2015 *2018 cents/kWh*	 *% Difference*	*Notes*
Avoided Retail Capacity Costs	2.91	3.05	1.72	-1.33	-44%	3,4,5,6,7
Avoided Retail Energy Costs	6.29	6.60	4.63	-1.97	-30%	8,9,11
Avoided Renewable Energy Credit	0.96	1.01	0.39	-0.62	-61%	8,10,11
Subtotal: Capacity and Energy	**10.16**	**10.66**	**6.75**	**-3.92**	**-37%**	
CO_2 non-embedded	**4.88**	**5.13**	**4.36**	**-0.76**	**-15%**	5
Transmission & Distribution	**-**	**-**	**2.11**	**2.11**	**-**	3,5,12
Value of Reliability	**-**	**-**	**0.01**	**0.01**	**-**	3,5,7,13
Capacity DRIPE	-	-	0.91	0.91	-	5,7
Energy DRIPE	1.18	1.24	1.91	0.67	54%	8,14
Subtotal: DRIPE	**1.18**	**1.24**	**2.81**	**1.58**	**128%**	**-**
Total	**16.22**	**17.02**	**16.05**	**-0.98**	**-6%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2018 dollars unless otherwise stated.
2. AESC 2015 values levelized (2016-2030) escalated with a factor of 1.05 to convert 2015$ to 2018$
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2015 cost (2015 $/kW-year) of $140.10/kW-year
AESC 2018 cost (2018 $/kW-year) of $83.09/kW-year
5. Distribution loss adjustment of 8.0%
6. Reserve margin adjustment of 17.2%
7. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
8. Wholesale risk premium adjustment of 8.0% assumed for AESC 2018. AESC 2015 assumes a WRP value of 9%
9. Avoided wholesale energy cost (2018 $/MWh) of $42.91/MWh
10. AESC 2018 REC price (2018 cents/kWh pre-adjustment) of 0.36 cents/kWh
11. Retail cost = avoided wholesale cost x (1 + wholesale risk premium)
12. Assumes T&D cost (2018 $/kW-year) of $94.00/kW-year
13. Assumes reliability value (2018 $/kW-year) of $0.58/kW-year, and a VOLL of $25.00/kWh
14. "Energy DRIPE" is the sum of intrastate electric energy, own-fuel, and electric cross-DRIPE values. In both AESC 2015 and AESC 2018, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
15. AESC 2015 data is from Exhibit 1-2 in AESC 2015. Small differences in values are due to rounding, except for (a) CO_2 non-embedded costs and (b) energy DRIPE which have been adjusted to reflect the AESC 2015 wholesale risk premium.

ES-Table 2. Illustration of avoided retail summer on-peak electricity cost components, AESC 2018 versus AESC 2015 Update

	AESC 2015 Update *2017 cents/kWh*	AESC 2015 Update *2018 cents/kWh*	AESC 2018 *2018 cents/kWh*	AESC 2018, relative to AESC 2015 Update *2018 cents/kWh*	 *% Difference*	***Notes***
Avoided Retail Capacity Costs	2.64	2.69	1.72	-0.97	-36%	3,4,5,6,7
Avoided Retail Energy Costs	5.64	5.75	4.63	-1.12	-19%	8,9,11
Avoided Renewable Energy Credit	0.99	1.01	0.39	-0.62	-61%	8,10,11
Subtotal: Capacity and Energy	**9.27**	**9.46**	**6.75**	**-2.71**	**-29%**	
CO2 non-embedded	**5.02**	**5.13**	**4.36**	**-0.76**	**-15%**	5
Transmission & Distribution	**-**	**-**	**2.11**	**2.11**	**-**	3,5,12
Value of Reliability	**-**	**-**	**0.01**	**0.01**	**-**	3,5,7,13
Capacity DRIPE	-	-	0.91	0.91	-	5,7
Energy DRIPE	1.21	1.23	1.91	0.67	54%	8,14
Subtotal: DRIPE	**1.21**	**1.23**	**2.81**	**1.58**	**128%**	**-**
Total	**15.50**	**15.81**	**16.05**	**0.23**	**1%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone for AESC 2018 and New England average for AESC 2015 Update, summer on-peak, on a 15-year levelized basis; all values are in 2018 dollars unless otherwise stated.
2. AESC 2015 Update values levelized (2017-2031) escalated with a factor of 1.020 to convert 2017$ to 2018$
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2015 Update cost (2017 $/kW-year) of $121/kW-year
AESC 2018 cost (2018 $/kW-year) of $83.09/kW-year
5. Distribution loss adjustment of 8.0%
6. Reserve margin adjustment of 17.2%
7. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
8. Wholesale risk premium adjustment of 8.0% assumed for AESC 2018. AESC 2015 Update assumes a WRP value of 9%
9. Avoided wholesale energy cost (2018 $/MWh) of $42.91/MWh
10. AESC 2018 REC price (2018 cents/kWh pre-adjustment) of 0.36 cents/kWh
11. Retail cost = avoided wholesale cost x (1 + wholesale risk premium)
12. Assumes T&D cost (2018 $/kW-year) of $94.00/kW-year
13. Assumes reliability value (2018 $/kW-year) of $0.58/kW-year, and a VOLL of $25.00/kWh
14. "Energy DRIPE" is the sum of intrastate electric energy, own-fuel, and electric cross-DRIPE values. In both AESC 2015 and AESC 2018, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
15. AESC 2015 Update data is from Table 5 in AESC 2015 Update and TCR workbooks. Small differences in values are due to rounding, except for (a) CO_2 non-embedded costs and (b) energy DRIPE which have been adjusted to reflect the AESC 2015 Update wholesale risk premium.

The following sections provide high-level results describing our findings for each of the avoided cost sections described in detail in this document.

Natural gas

At a high level, AESC 2018 assumes that Henry Hub natural gas prices are lower, and stay lower longer, relative to the assumptions used in AESC 2015. In addition, the AESC 2018 levelized basis is higher than the previous projections because AESC 2018 anticipates little new pipeline capacity will be added after 2019.

On a 15-year levelized basis, AESC 2018 projects a Henry Hub price of $4.39/MMBtu, 19.4 percent lower than the AESC 2015 value of $5.44/MMBtu and 5.2 percent lower than the AESC 2015 Update of $4.62/MMBtu (see ES-Table 3). AESC 2018 attributes the decrease in Henry Hub prices to higher associated gas production and another downward adjustment in breakeven drilling and operating costs in the major shale and tight gas producing regions compared to AESC 2015 and AESC 2015 Update.

ES-Table 3. Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials for AESC 2018, AESC 2015, and AESC 2015 Update

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2015 (2016–2030)	2018 $/MMBtu	$5.44	$6.23	$0.80
AESC 2015 Update (2017–2031)	2018 $/MMBtu	$4.62	$5.55	$0.93
AESC 2018 (2018–2032)	2018 $/MMBtu	$4.38	$5.39	$1.01
Change from AESC 2015 to AESC 2018	%	-19.4%	-13.6%	-
Change from AESC 2015 Update to AESC 2018	%	-5.2%	-2.9%	-

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent.

While prices for Henry Hub and the resulting Algonquin Citygates are lower in AESC 2018 than in AESC 2015, we observe a more complex set of trends for the avoided cost of natural gas for retail customers (see ES-Table 4). In Southern New England, avoided natural gas costs are lower in AESC 2018 than in AESC 2015 because pipeline capacity costs in AESC 2018 are based on incremental expansion costs, not the lower cost of existing capacity as in AESC 2015. The main reason that Northern New England costs are lower relative to Southern New England and AESC 2015 is that natural gas delivered through Canada has become a significant marginal resource, as new pipeline capacity from the Marcellus Shale region has reduced the Dawn Hub price basis compared to the Henry Hub. Since the Northern New England market is closer to this source of supply, the avoidable pipeline delivery cost is lower than it is for Southern New England. For Vermont (not shown in ES-Table 4), peak period costs are higher than in AESC 2015 because variable operating costs for the propane-based peaking facilities have been added to the avoided costs, while the avoidable natural gas costs for the remainder of the year are lower than in AESC 2015 because of lower projected natural gas prices at the Dawn Hub.

ES-Table 4. Avoided costs of gas for all retail customers by end-use assuming no avoidable margin

	Units	Southern New England	Northern New England
AESC 2015 (2016–2030)	2018 $/MMBtu	$6.80	$7.91
AESC 2015 Update (2017–2031)	2018 $/MMBtu	$5.96	$7.18
AESC 2018 (2018–2032)	2018 $/MMBtu	$7.40	$7.18
Change from AESC 2015 to AESC 2018	%	8.8%	-9.2%
Change from AESC 2015 Update to AESC 2018	%	24.2%	0.0%

Note: AESC also calculates the avoided cost of gas for retail customers assuming some avoidable margin, and avoided costs for customers in Vermont. This additional detail is described in Chapter 2 Avoided Natural Gas Costs*.*

Fuel oil and other fuels

In general, we find that avoided levelized costs for residential fuel oil and other fuels are generally higher than was estimated in AESC 2015, while levelized costs for commercial fuel oil is slightly lower than was estimated in AESC 2015. The primary source of this difference is a change in data sources from the previous AESC study, as summarized below. ES-Table 5 displays the levelized avoided fuel costs for AESC 2018.

ES-Table 5. Avoided costs of retail fuels (15-year levelized, 2018 $/MMBtu)

	Residential						Commercial	
	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 (2016–2030)	$20.15	$19.26	$21.98	$19.61	$7.14	$8.12	$19.63	$17.29
AESC 2018 (2018–2032)	$22.17	$31.11	$19.88	$22.83	$13.40	$21.60	$18.47	$16.26
Change from AESC 2015 to AESC 2018	10.0%	61.5%	-9.6%	16.4%	87.8%	165.9%	-5.9%	-5.9%

The avoided costs for AESC 2018 differ substantially from AESC 2015 for propane and wood fuels, and less so for the other fuels. For non-wood products, AESC 2018 starts with the New England fuel prices in the U.S. Energy Information Administration (EIA) State Energy Data System (SEDS) and escalates prices with the crude oil price forecast. For biofuels, it is priced at a 3 percent premium to distillate. All sector propane prices are consistently higher than distillate prices for all years in SEDS. For residential wood fuels, AESC 2018 surveyed various state energy sources, which give much higher retail prices than those previously used in AESC 2015 (although they had been higher in AESC 2013). The prices used in AESC 2015 were mostly based on Annual Energy Outlook (AEO) 2014 (i.e., a secondary source generally calibrated to the most recent price data). AESC 2018 has instead relied upon available primary sources whenever possible.

Capacity

AESC 2018 develops capacity prices for annual commitment periods starting in June 2018 under a future with no new energy efficiency (see ES-Table 6). The capacity prices (and resulting avoided capacity costs) are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market (FCM). The forecast capacity prices are based on the experience in recent auctions and expected changes in demand, supply, and market rules. These prices are applied differently for cleared resources, non-cleared energy efficiency, and non-cleared demand response.

On a 15-year levelized basis, the 2018 AESC forecast is 48 percent lower than what was estimated in the 2015 AESC study for the same years. Specifically, AESC 2015 assumed that the (at the time) existing capacity surplus would rapidly disappear, bringing the capacity price close to ISO New England's estimate of net cost of new entry (CONE). While the capacity surplus did disappear, the subsequent capacity auction (FCA 9) cleared well below the previous estimates of net cost of new entry (CONE), and the market price fell substantially in the years following. Since AESC 2015, a large amount of capacity has been added, and ISO New England has reduced its estimate of CONE and shifted the demand curve. These factors have again created substantial surplus capacity. Due to changes in the market structure (particularly ISO New England's CASPR, or Competitive Auctions with Sponsored Policy Resources) and expected state-mandated procurement of a large amount of clean energy capacity, retiring major generation is likely to be replaced by renewable resources. Generators will have strong incentives to avoid abrupt retirement, making price spikes (as observed in FCA 8 and 9) less likely.

ES-Table 6. AESC 2018 capacity prices (2018 $ / kW-month)

Commitment Period (June to May)	FCA	AESC 2018	AESC 2015	AESC 2015 Update
2018/2019	9	**$9.81**	$13.60	$9.57
2019/2020	10	**$7.28**	$11.85	$6.92
2020/2021	11	**$5.35**	$11.89	$9.12
2021/2022	12	**$4.74**	$12.29	$8.51
2022/2023	13	$4.84	$12.20	$8.08
2023/2024	14	$4.94	$11.93	$7.53
2024/2025	15	$5.22	$12.55	$8.48
2025/2026	16	$5.65	$12.55	$9.21
2026/2027	17	$6.13	$12.64	$10.13
2027/2028	18	$6.60	$12.37	$10.87
2028/2029	19	$7.07	$13.08	$11.77
2029/2030	20	$7.54	$13.42	$12.66
2030/2031	21	$6.60	-	$14.09
2031/2032	22	$7.07	-	$13.98
2032/2033	23	$7.54	-	-
2033/2034	24	$6.60	-	-
2034/2035	25	$7.07	-	-
2035/2036	26	$7.54	-	-
15-year levelized		$6.42	$12.32	$9.62
Percent Difference (AESC 2018 relative to other studies)		-	-48%	-33%

Notes: All prices are in 2018 $ per month. Levelization periods are 2015/2016 to 2029/2030 for AESC 2015 and 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018. Dashes in AESC 2015 and AESC 2015 Update refer to years in which capacity prices were extrapolated, rather than modeled. Bolded prices for FCAs 9-12 reflect actual prices stated in 2018$.
Source: AESC 2015 Exhibit 5-32.

Energy

ES-Table 7 shows levelized costs (over 15 years) for the Western and Central Massachusetts (WCMA) reporting region. Prices are shown for all hours, and for the four traditional AESC costing periods. On an annual average basis, the 15-year levelized prices in the 2018 AESC study are 18 percent lower than the prices modeled in the 2015 AESC study. Key drivers of these lower prices include lower Henry Hub natural gas prices, lower RGGI prices, lower overall demand for electricity (even in a future with no incremental energy efficiency), more low- or zero-variable operating cost renewables (caused by changes to the RPS in states like Connecticut and Rhode Island), and the addition of a new transmission line from Canada. (Note that these factors are not listed in a particular order.) This observed decrease is similar to the change in avoided energy costs observed between the 2013 AESC study and the 2015 AESC study.

In addition, AESC 2018 features a lower ratio of summer peak prices to the annual average than observed in previous AESC studies. This difference can be attributed to the increased levels of solar generation that are largely coincident with this period and which have a marginal cost of zero dollars per

MWh. It may also be due to differences in month-to-month wholesale gas costs (which are driven by new recent historical data on month-to-month gas costs) and higher levels of zero-marginal cost imports.

ES-Table 7. 15-year levelized cost comparison for WCMA region (2018 $ / MWh)

	Annual All Hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	$48.56	$55.67	$51.41	$42.91	$36.72

Notes: All prices have been converted to 2018 $ per MWh. Levelization is calculated over 2018–2032 for AESC 2018 with a real discount rate of 1.34 percent for AESC 2018. Prices are wholesale.

ES-Table 8 compares 15-year levelized costs between AESC 2015 and AESC 2018 for each of the six New England states. These values incorporate the relevant REC costs, as well as a wholesale risk premium of 8 percent.

ES-Table 8. Avoided retail energy costs, AESC 2018 vs. AESC 2015 (15-year levelized costs, 2018 $ / kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	1	Connecticut	$0.065	$0.060	$0.050	$0.044
	2	Massachusetts	$0.064	$0.059	$0.050	$0.044
	3	Maine	$0.059	$0.055	$0.046	$0.040
	4	New Hampshire	$0.065	$0.061	$0.052	$0.045
	5	Rhode Island	$0.063	$0.058	$0.049	$0.043
	6	Vermont	$0.064	$0.059	$0.050	$0.043
AESC 2015	1	Connecticut	$0.082	$0.076	$0.077	$0.062
	2	Massachusetts	$0.081	$0.076	$0.077	$0.062
	3	Maine	$0.070	$0.064	$0.065	$0.051
	4	New Hampshire	$0.080	$0.075	$0.075	$0.061
	5	Rhode Island	$0.077	$0.071	$0.071	$0.057
	6	Vermont	$0.070	$0.065	$0.066	$0.051
Delta	1	Connecticut	-$0.017	-$0.016	-$0.026	-$0.018
	2	Massachusetts	-$0.017	-$0.016	-$0.026	-$0.018
	3	Maine	-$0.011	-$0.009	-$0.019	-$0.012
	4	New Hampshire	-$0.015	-$0.014	-$0.023	-$0.016
	5	Rhode Island	-$0.014	-$0.013	-$0.022	-$0.014
	6	Vermont	-$0.007	-$0.006	-$0.017	-$0.009
Percent Difference	1	Connecticut	-21%	-21%	-34%	-29%
	2	Massachusetts	-21%	-21%	-34%	-30%
	3	Maine	-16%	-14%	-29%	-23%
	4	New Hampshire	-18%	-19%	-31%	-26%
	5	Rhode Island	-18%	-18%	-31%	-25%
	6	Vermont	-9%	-9%	-25%	-17%

Notes: These costs are the sum of wholesale energy costs and wholesale renewable energy certificate (REC) costs, increased by a wholesale risk premium of 8 percent (9 percent in AESC 2015), except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2018 $ per kWh. Levelization periods are 2016–2030 for AESC 2015 and 2018–2032 for AESC 2018. The real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018. Source: AESC 2015 Exhibit 1-6.

RPS compliance

Relative to AESC 2015, AESC 2018 sees generally lower prices for meeting RPS compliance (see ES-Table 9). In the near term, a supply boom stimulated mainly by distributed generation policies surpasses demand, creating a market surplus. This surplus is sustained in the long term as substantial supply driven by large-scale renewable procurement policies in Connecticut, Massachusetts, and Rhode Island are expected to become operational without matching growth on the demand side.

ES-Table 9. Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$2.82	$0.21	$1.72	$1.51	$2.39	$0.53
MA CES	NA	NA	$0.45	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.44	$3.43	$0.03	$1.46
Total	**$3.76**	**$0.51**	**$3.61**	**$4.94**	**$2.42**	**$1.99**

Note: Each state has multiple Classes or Tiers. Rhode Island and Maine have two, Connecticut and Vermont have three, and Massachusetts and New Hampshire have four. For simplicity, we sum avoided costs for all non-Class I/New RPS policies together in the "all other classes" row.

Non-embedded environmental compliance

AESC 2018 develops two approaches to the total environmental costs of greenhouse gas (GHG) emissions. The first approach, based on global marginal abatement costs, establishes a total environmental cost of $100 per short ton of CO_2-eq emissions. This is identical to the prior AESC 2015 value, reflecting the fact that best available cost estimates for large-scale carbon capture and sequestration (CCS) have barely changed since 2005. The second approach, based on New England marginal abatement costs, establishes a total environmental cost of $174 per short ton of CO_2-eq emissions, based on a projection of future costs of offshore wind energy. In addition, AESC 2018 establishes a non-embedded NO_X emission cost of $31,000 per ton of N, based on a review of findings in the literature, which translates into an avoided wholesale cost for NO_X of $1.58 per MWh.

DRIPE

DRIPE refers to the reduction in prices in the wholesale markets for capacity and energy, relative to the prices forecast in the Reference case, resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

AESC 2018 models DRIPE benefits induced by reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets. DRIPE results in AESC 2018 differ from those in AESC 2015 because of differences in analytical approach, assumptions about hedging and decay, and new commodity forecasts. We find higher energy DRIPE values, lower natural gas supply DRIPE values, and lower natural gas transportation DRIPE values. In AESC 2018, we estimate values for electric capacity DRIPE and oil DRIPE where these were calculated to be either zero in AESC 2015, or were simply not present in earlier versions.

Transmission and distribution

This chapter is new to AESC 2018. Here, AESC 2018 expands upon the treatment of electric T&D avoided cost components in prior AESC studies, which primarily summarized estimates provided by Study Group members. AESC 2018 calculates an avoided cost for Pool Transmission Facilities (PTF) of $94/kW-year in 2018 dollars. Note that this represents the PTF cost only; program administrators can still add avoided distribution and non-PTF transmission costs. Program administrators that use the avoided PTF costs calculated in AESC 2018 should include only local transmission investments (those not eligible for PTF treatment) in their own, additional avoided transmission analyses.

The following steps summarize a standardized approach to estimate generic avoidable transmission or distribution costs:

- Step 1: Select a time period for the analysis, which may be historical, prospective, or a combination of the two.
- Step 2: Determine the actual or expected relevant load growth in the analysis period, in megawatts.
- Step 3: Estimate the load-related investments in dollars incurred to meet that load growth.
- Step 4: Divide the result of Step 3 by the result of Step 2 to determine the cost of load growth in $/MW or $/kW.
- Step 5: Multiply the results of Step 4 by a real-levelized carrying charge to derive an estimate of the avoidable capital cost in $/kW-year.
- Step 6: Add an allowance for operation and maintenance of the equipment to derive the total avoidable cost in $/kW-year.

Reliability

This issue is new in AESC 2018. AESC 2015 and earlier versions did not attempt to quantify this benefit of lower load. Reducing electric loads can improve reliability in several ways, which differ among generation, transmission, and distribution. Our analysis addresses the effect of increased reserve margins based on generation reliability, the potential and obstacles in estimating the effect of load levels on T&D overloads and outages, and the value of lost load. We then develop estimates of the value of increased generation reliability per kilowatt of peak load reduction.

We estimate that the 15-year levelized benefit of increasing generation reserves through reduced energy usage is $0.65/kW-year for cleared resources and $6.60/kW-year for uncleared load reductions.

Sensitivities

For AESC 2018, we conducted analysis across four sensitivities (in addition to the costs calculated under the main 2018 AESC case). These sensitivities include testing: (1) higher and (2) lower natural gas prices than modeled under the main 2018 AESC case, as well as testing (3) higher (High Load) and (4) lower (With EE) electricity demand levels than modeled under the main 2018 AESC case.

In general, we find that the change in energy prices and DRIPE effects in the higher and lower natural gas price cases are consistent in both direction and magnitude with the change in Henry Hub price modeled under each of these two scenarios. Per the direction of the Study Group, we did not estimate capacity prices or RPS compliance costs under these two sensitivities. Meanwhile, in the High and Low Load sensitivities, energy prices and DRIPE effects do not substantially differ from the values observed in the main 2018 AESC case, largely because the main driver of price variability (natural gas prices) is unchanged in these two sensitivities. For capacity prices, we find that long-term equilibrium in the With EE and High Load sensitivities oscillate between a price similar to the cost of new entry and a lower price following major additions, as in the main AESC 2018 case. In the sensitivity with higher electricity demand, RPS compliance costs are generally higher relative to the main 2018 AESC case, reflecting the increased demand for RECs driven by greater overall demand levels. Likewise, in the sensitivity with lower electricity demand, RPS compliance costs are generally lower relative to the main 2018 AESC case, reflecting a decreased demand for RECs.

2. AVOIDED NATURAL GAS COSTS

The following sections first discuss the drivers of natural gas commodity prices (i.e., the long-term price for natural gas at Henry Hub and other price points upstream of New England). The discussion then addresses factors impacting the basis price for natural gas in New England, and ends with a discussion of how to quantify avoided costs of natural gas.

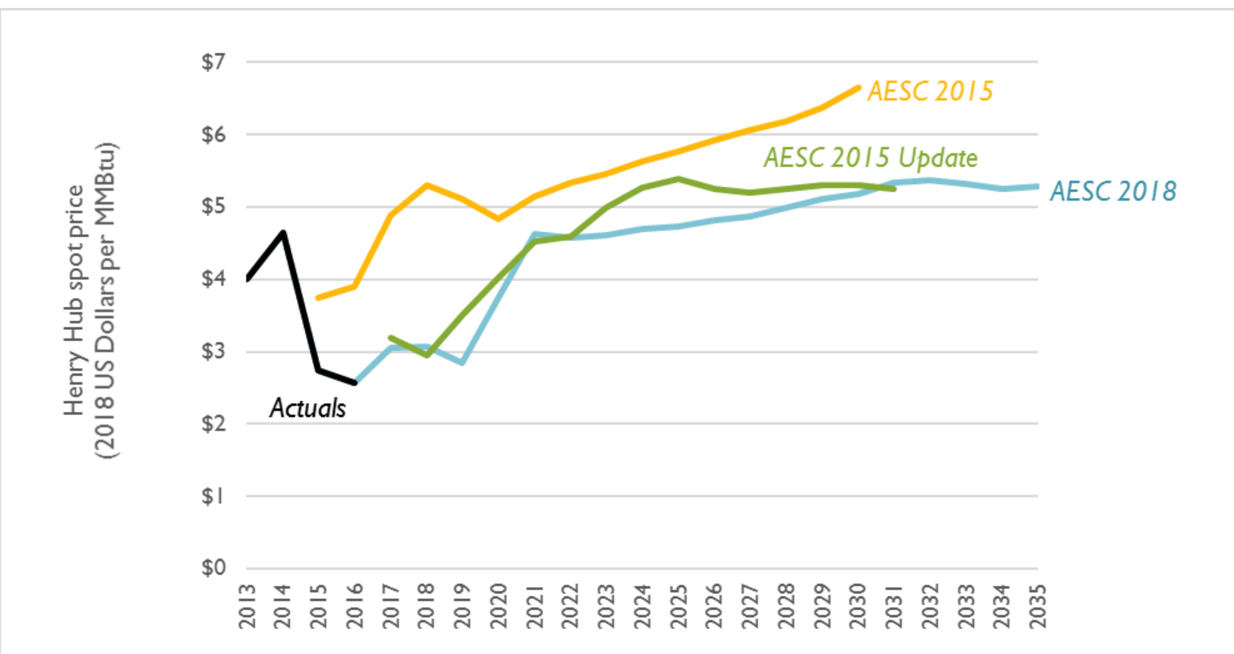
AESC 2018 projects avoided natural gas costs to power plants and to end-use gas customers in New England. The wholesale natural gas price is the market price of gas that is sold to local distribution companies (LDCs), electricity generators, and other large end-users at interstate pipeline delivery points. The avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the LDC (the "citygate cost"); and (2) the avoided cost of delivering gas on the LDC system (the "retail margin"). As with previous versions of AESC, natural gas avoided costs are presented with and without the retail margin.

Major findings of AESC 2018 are summarized below.

2.1. Overview of Findings

Figure 1 illustrates the AESC 2018 base case Henry Hub price projection compared to AESC 2015 and the AESC 2015 Update.

Figure 1. Comparison of AESC Henry Hub prices



At a high level, AESC 2018 assumes that Henry Hub natural gas prices are lower, and stay lower longer, relative to the assumption used in AESC 2015. On a 15-year levelized basis, the AESC 2018 base case of $4.39/MMBtu is 19.4 percent lower than the AESC 2015 of $5.44/MMBtu and 5.2 percent lower than the AESC 2015 Update of $4.62/MMBtu for projections of Henry Hub prices.[3] AESC 2018 attributes the decrease in Henry Hub prices to higher associated gas production and another downward adjustment in breakeven drilling and operating costs in the major shale and tight gas producing regions compared to AESC 2015 and AESC 2015 Update.

Previous AESC studies have consistently used NYMEX basis futures as a starting point for forecasting Algonquin Citygate (ACG) prices that ultimately determine New England electricity prices.[4] Those futures reflect current market expectations—weather, new pipeline construction, etc. Table 1 summarizes the AESC 2018 projection of the ACG and corresponding basis differential from the Henry Hub. The AESC 2018 levelized basis is higher than the previous projections because AESC 2018 anticipates little new pipeline capacity will be added after 2019.

Table 1. Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials for AESC 2018, AESC 2015, and AESC 2015 Update

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2015 (2016–2030)	2018 $/MMBtu	$5.44	$6.23	$0.80
AESC 2015 Update (2017–2031)	2018 $/MMBtu	$4.62	$5.55	$0.93
AESC 2018 (2018–2032)	2018 $/MMBtu	$4.38	$5.39	$1.01
Change from AESC 2015 to AESC 2018	%	-19.4%	-13.6%	-
Change from AESC 2015 Update to AESC 2018	%	-5.2%	-2.9%	-

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent.

A summary of the AESC 2018 natural gas avoided cost estimates for the three New England regions is shown in Table 2 and Table 3. The results are shown with and without the avoided LDC margin, and as compared to values from the AESC 2015 and AESC 2015 Update.

The natural gas avoided costs for Southern New England are higher than AESC 2015 and the AESC 2015 Update because pipeline capacity costs in AESC 2018 are based on incremental expansion costs, not the lower cost of existing capacity as in AESC 2015. Tight pipeline capacity also causes LDCs to buy more gas

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[3] The 15-year levelization periods for AESC 2015 (2016–2030), AESC 2015 Update (2017–2031), and AESC 2018 (2018–2032). The discount rates used for AESC 2015 (2.43 percent), AESC 2015 Update (1.43 percent), and AESC 2018 (1.34 percent).

[4] Consultation with Vermont Gas resulted in a different methodology for estimating basis for Dominion South (Marcellus) and Dawn. Over the 2020-2035 period, AESC 2018 uses the 2019 futures for Dominion and Dawn; ($0.54) and ($0.20), respectively.

at local market prices during the winter and keep New England gas prices high during periods of peak demand.

For Northern New England, the avoided natural gas costs are lower than AESC 2015, about the same as the AESC 2015 Update, and lower than the AESC 2018 results for Southern New England. The main reason that Northern New England costs are low relative to Southern New England and AESC 2015 is that gas delivered through Canada has become a significant marginal resource, as new pipeline capacity from the Marcellus Shale region has reduced the Dawn Hub price basis compared to the Henry Hub. Since the Northern New England market is closer to this source of supply, the avoidable pipeline delivery cost is lower than it is for Southern New England.

For Vermont, the design day avoided costs are very similar to AESC 2015 because upstream and downstream capacity costs are about the same. Peak period costs are higher than in AESC 2015 because variable operating costs for the propane-based peaking facilities have been added to the avoided costs. The avoidable natural gas costs for the remainder of the year are lower than in AESC 2015 because of lower projected gas prices at the Dawn Hub.

Table 2. Avoided costs of gas for retail customers by end-use assuming no avoidable margin

Study	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2015	6.30	6.85	7.03	6.89	6.51	6.86	6.71	6.80
AESC 2015 Update	5.45	6.00	6.18	6.04	5.66	6.01	5.85	5.96
AESC 2018	5.85	7.55	8.08	7.64	6.56	7.58	7.14	7.40
2015 to 2018 change	*-7%*	*10%*	*15%*	*11%*	*1%*	*10%*	*6%*	*9%*
2015 Update to 2018 change	*7%*	*26%*	*31%*	*26%*	*16%*	*26%*	*22%*	*24%*
Northern New England								
AESC 2015	6.30	8.07	8.66	8.19	6.96	8.09	7.60	7.91
AESC 2015 Update	5.44	7.34	7.98	7.47	6.15	7.37	6.83	7.18
AESC 2018	5.65	7.34	7.82	7.40	6.37	7.37	6.93	7.18
2015 to 2018 change	*-10%*	*-9%*	*-10%*	*-10%*	*-8%*	*-9%*	*-9%*	*-9%*
2015 Update to 2018 change	*4%*	*0%*	*-2%*	*-1%*	*4%*	*0%*	*1%*	*0%*
Vermont								
Study	**Design Day**	**Peak Days**	**Remaining Winter**	**Shoulder / Summer**				
AESC 2015 (a)	549.00	22.91	7.88	6.50				
AESC 2015 Update (b)	548.73	23.87	7.08	5.69				
AESC 2018	561.39	26.27	4.89	4.48				
2015 to 2018 change	*2%*	*15%*	*-38%*	*-31%*				
2015 Update to 2018 change	*2%*	*10%*	*-31%*	*-21%*				

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent.

Table 3. Avoided costs of gas for retail customers by end-use assuming some avoidable margin

Study	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
Southern New England								
AESC 2015	6.95	8.28	8.73	8.53	7.15	8.06	7.74	7.71
AESC 2015 Update	6.08	7.40	7.83	7.64	6.28	7.18	6.85	7.26
AESC 2018	6.18	7.89	9.17	8.58	6.99	8.34	7.75	8.17
2015 to 2018 change	*-11%*	*-5%*	*5%*	*1%*	*-2%*	*3%*	*0%*	*6%*
2015 Update to 2018 change	*2%*	*7%*	*17%*	*12%*	*11%*	*16%*	*13%*	*12%*
Northern New England								
AESC 2015	6.84	9.30	10.12	9.60	7.46	9.04	8.41	8.76
AESC 2015 Update	5.98	8.54	9.38	8.84	6.64	8.28	7.62	8.00
AESC 2018	5.96	7.65	8.83	8.28	6.65	7.88	7.34	7.65
2015 to 2018 change	*-13%*	*-18%*	*-13%*	*-14%*	*-11%*	*-13%*	*-13%*	*-13%*
2015 Update to 2018 change	*0%*	*-10%*	*-6%*	*-6%*	*0%*	*-5%*	*-4%*	*-4%*

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent.

2.2. Gas Commodity Costs

Background

Over the past decade, there have been dramatic changes in the U.S. natural gas market. In 2007 total U.S. production was 55.3 billion cubic feet per day (Bcfd), roughly the same as a decade earlier and 10 percent below the early 1970s peak. Moreover, the United States was importing 10.4 Bcfd (net), or about 17 percent of demand. In 2017, the EIA estimates that production will average 79 Bcfd and that the United States will become a net exporter of natural gas. The primary driver has been shale gas, which increased from 5.3 Bcfd in 2007 to nearly 45 Bcfd in 2017.

These supply and demand changes have upended traditional views of U.S. natural gas prices in many ways. The immense productivity improvements overturned the idea that natural gas drilling was an increasing-cost business and that prices must increase continually to sustain production growth. Several factors have invalidated most models and forecasts of natural gas prices: the large dispersion of shale and conventional natural gas production basins; varying prices of natural gas liquid (NGL) bi-products sold by gas producers; volumes of associated gas from shale oil production; contracts that require production regardless of price; a growing export market for U.S. gas; and large-scale changes in natural gas infrastructure.[5] The market's perception has changed from shortage to abundance.

Immense supply growth and lower prices impacted U.S. gas consumption. Between 2007 and 2017 total consumption increased at an average annual rate of 1.5 percent, versus only 0.2 percent annually over the prior decade. Electric generation was the sector that changed the most due to this growth in supply, absorbing over 60 percent of the net supply growth. Industrial gas use also increased, growing at a rate of 1.6 percent from 2007 to 2017 versus a 2.4 percent rate of decline the prior decade.

Both the magnitude and location of this supply and demand growth is resulting in systemic changes to the U.S. natural gas market. Regions that were historically short of gas, such as the Northeast, are now gas-long.[6] Massive growth in LNG export terminals along the Gulf Coast and pipelines moving gas to Mexico are making the Gulf Coast gas-short, versus a region that previously moved surplus gas to the large consuming areas in the Northeast and Midwest. Pipelines built last century to move gas north and east are now contending with the need to move Marcellus/Utica gas south, west, and north. New pipeline capacity and new export markets are changing U.S. natural gas price dynamics. Traditional gas supply-area hubs on the Gulf Coast might also become gas demand-area hubs, depending on export growth. Similarly, historical gas demand-area hubs in the Northeast or Midwest might function as supply hubs during non-winter peak periods.

How do these market changes affect the cost of natural gas to New England? Previous AESC reports, as well as AESC 2018, posited that there were three primary parts in developing avoided natural gas costs, including:

1. The natural gas commodity cost at the point of purchase or production (the "supply area" cost);
2. The pipeline transportation cost from the supply area to the LDC citygate or electric generating plant; and
3. The retail distribution margin from the citygate to the end-user's burner tip.

The massive investments in pipeline infrastructure and increased liquidity at many supply-area and market-area hubs now allow gas buyers and sellers to arbitrage natural gas prices across much of the United States. Natural gas price formation no longer follows the historical "supply cost plus pipeline transportation" model. New market dynamics now allow prices to reflect real-time conditions. At times, these conditions might reflect the full costs of gas plus transportation, but more often prices now reflect

[5] NGL refers to Natural Gas Liquids. These are hydrocarbons such as ethane, propane, butanes, etc. that are produced in conjunction with natural gas. These liquids are often sold separately.

[6] We use the census region definition for the Northeast, which is subdivided into the Middle Atlantic (NY, NJ, and PA) and New England (CT, MA, VT, RI, NH, ME). See: http://www2.census.gov/geo/docs/maps-data/maps/reg_div.txt. As a practical matter, the new supply hubs are in the Middle Atlantic due to Marcellus and Utica gas production growth.

local supply-demand pressures that are either higher or lower than the historical model. AESC 2018 sees prices at hubs that are oversupplied that exhibit only variable costs pricing. These costs might be zero or even negative for natural gas because of must-produce contracts and only-fuel charges for pipeline transportation. During high-demand or supply-short periods, some marketers can realize prices significantly above their cost because they have price hedges or stored gas and additionally own firm pipeline transportation.

Below we discuss the changing dynamics of natural gas pricing in the United States and describe an integrated approach to derive avoided gas costs in New England.

Supply area natural gas cost

As in previous AESC studies**,** AESC 2018 concludes that the Henry Hub should serve as the foundation for developing price forecasts relevant to New England markets. The rationale for this choice is that Henry Hub has been the U.S. natural gas price benchmark since the early 1990s and is likely to continue that role in the foreseeable future. There are numerous reasons for choosing Henry Hub.

1. Foremost, perhaps, is that it is the most highly traded natural gas pricing point in the United States. According to the Chicago Mercantile Exchange (CME), the NYMEX Henry Hub contract (symbol "NG") is the third-largest physical commodity futures contract in the world by volume.[7] The New York Mercantile Exchange (NYMEX) trades Henry Hub monthly gas with contracts extending over the next 10 calendar years (currently through December 2029).

2. Many natural gas purchase and sales contracts for natural gas are tied to the NYMEX because of transparency and liquidity. Moreover, they allow market participants the ability to hedge and to manage risk.

3. For many trading points (hubs) Henry Hub serves as the derivative pricing market in the form of basis trades; i.e., the difference between the Henry Hub price and the price at a different hub.

4. While regional supply and demand dynamics will continue to evolve, the Gulf Coast (Texas and Louisiana) currently absorb nearly 30 percent of domestic gas supply (local consumption and exports) and with new LNG terminal construction that proportion could rise to nearly 50 percent by 2030.[8] These volumes strongly favor Henry Hub as the primary marginal pricing point for gas over the forecast period.

5. EIA (in its Annual Energy Outlook, or AEO) and many other organizations base their price forecasts on Henry Hub.

[7] Details on the NYMEX Henry Hub Contract can be found on the Chicago Mercantile Exchange (CME) website: http://www.cmegroup.com/trading/energy/nymex-natural-gas-futures.html.

[8] AEO 2017 Reference Case. See: https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf.

Although there are monthly NYMEX natural gas price quotes through 2029, the number of trades drops sharply beyond two years; i.e., there is decreasing liquidity. In the near term, Henry Hub provides the market with a collective view of the price necessary to balance demand and supply. This market view is affected by current conditions, e.g., storage levels, near-term demand and supply expectations, and drilling activity. Gas price hedging traditionally peaks in the winter, which is reflected in NYMEX NG price seasonality. Thus, as in previous AESC studies, AESC 2018 relies on NYMEX futures for monthly Henry Hub gas prices for the medium-term natural gas price forecast. In addition, AESC 2018 uses the seasonality in monthly prices observed in the NYMEX futures to develop long-term monthly trends for the Henry Hub gas price.

Beyond the medium term and starting in 2020, AESC 2018 uses AEO 2017 for our forecast of Henry Hub gas prices. The AEO 2017 uses the EIA's National Energy Modeling System (NEMS) model to produce different cases for future Henry Hub prices.[9] Previous AESC studies have used the EIA's AEO because the inputs and models are public, transparent, and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among fuels. The AEO 2017 Reference case is the basis for our primary New England natural gas price forecasts.[10] Key assumptions in the Reference case include:

1. Trend improvement in known technologies, along with a view of economic and demographic trends reflecting the current central views of leading economic forecasters and demographers.
2. Current laws and regulations affecting the energy sector, including sunset dates for laws that have them, are unchanged throughout the projection period. The potential impacts of proposed legislation, regulations, or standards are not reflected in the Reference case.

Sensitivity of AESC 2018 natural gas prices

Given the uncertainty in the AEO 2017 Reference case modeling assumptions (drilling costs, regulations, pipeline infrastructure, resource base, finding-rate parameters, production profiles, productivity changes, regulations and policies, tax rates, oil prices, etc.); AESC 2018 also provides low and high natural gas price cases based on AEO 2017 side cases.[11] Some of the highlights in the AEO 2017 report describing the three cases include:

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[9] For NEMS documentation see: https://www.eia.gov/analysis/reports.cfm#/T1601,T144.

[10] For a description of assumptions in AEO 2017 see *Assumptions to the Annual Energy Outlook 2017*: July 2017: https://www.eia.gov/outlooks/aeo/assumptions/. Note that EIA also modeled an AEO 2017 Reference case without the Clean Power Plan—Henry Hub prices in this separate scenario are very similar to the main Reference case, differing by only +/- 3.0 percent from 2017 to 2035.

[11] See the Annual Energy Outlook 2017 Report: https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf. Note that the 2018 update to the Annual Energy Outlook was released too late to be incorporated into our modeling. While we were able to obtain preliminary modeling results for AEO 2018 from https://www.eia.gov/outlooks/aeo/workinggroup/oil-

- Reference Case. Beginning in 2021 natural gas production in the Reference case is projected to grow at a lower rate than the prior decade due in part to a moderation of net export growth and more efficient natural gas use. Gas prices slowly rise. However, rising prices are moderated by assumed advances in oil and natural gas extraction technologies. Hub prices rise because of increased drilling levels, production expansion into less prolific and more expensive-to-produce areas, and demand from both petrochemical and liquefied natural gas export facilities. Moderate natural gas prices raise the demand for U.S. LNG exports to Europe, Latin America, and Asia. Gross exports rise from roughly 8 Bcfd in 2020 to over 12 Bcfd in 2035.

- Low Price Case. The AEO 2017 side case that embodies lower natural gas prices is called "High Oil and Gas Resource Technology." Lower costs and higher resource availability allow for increased levels of production at lower prices which increases both domestic consumption and exports. Estimated ultimate recovery per shale gas, tight gas, and tight oil well in the United States, and undiscovered resources in Alaska and the offshore lower 48 states are 50 percent higher than in the Reference case. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50 percent higher than in the Reference case. Also, tight oil and shale gas resources are added to reflect new plays or the expansion of known plays. By 2035, domestic gas production is about 23 Bcfd higher than in the Reference case. Lower natural gas and oil prices stimulate economic growth, resulting in higher natural gas consumption and exports. By 2035, consumption is 10 Bcfd higher and LNG exports are 11 Bcfd higher than in the Reference case.

- High Price Case. The AEO 2017 side case that results in higher natural gas prices is "Low Oil and Gas Resource Technology." Henry Hub prices near historical highs drive down domestic consumption and exports. Estimated ultimate recovery per shale gas, tight gas, and tight oil well in the United States and undiscovered resources in Alaska and the offshore lower 48 states are 50 percent lower than in the Reference case. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50 percent lower than in the Reference case. Domestic natural gas production in 2035 is only 76 Bcfd, not much different from current volumes. Higher prices constrain growth in gas consumption and LNG exports. In 2035, domestic consumption is almost 17 Bcfd lower than in the Reference case, while LNG exports are 4 Bcfd lower.

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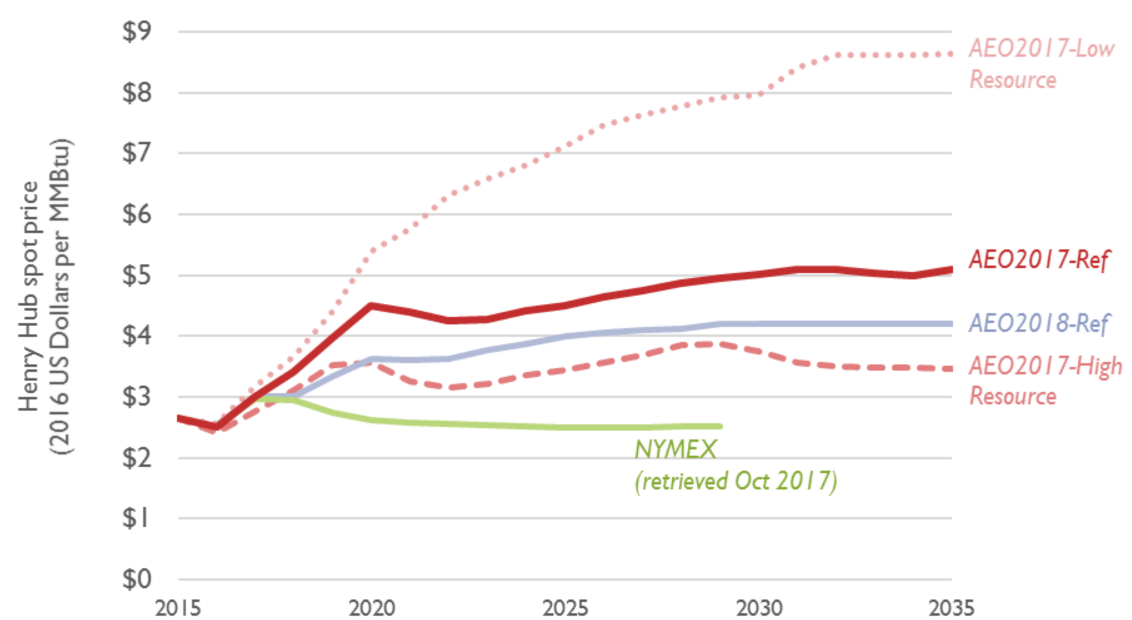
naturalgas/pdf/AEO2018%20PNGBA%20working%20group%20session%202_2017_09_21.pdf, final modeling inputs and methodology were not available in time to be included in our modeling. For these reasons, we relied on AEO 2017 instead of AEO 2018. Final AEO 2018 natural gas prices were released in February 2018 (available at https://www.eia.gov/outlooks/aeo/tables_ref.php) and are presented in this document for comparative purposes.

Figure 2 shows potential forecasts of Henry Hub prices using the current NYMEX futures (symbol "NG") and the three relevant cases in the AEO 2017.[12] Between 2018 and 2019, we use the NYMEX prices series before shifting to an average of NYMEX/AEO prices in 2020, and fully to the AEO forecasts beginning in 2021.[13]

Figure 2. Henry Hub gas price forecasts



Note: In AESC 2018, we used a combination of NYMEX futures (for the near term) and the AEO 2017 Reference case (for the long term) as our main reference points for constructing a projection for Henry Hub prices. All other prices shown in this figure are for informational purposes only. The final AEO 2018, for example, closely follows the Henry Hub price trajectory in the AEO 2017 Reference case, but at a price that is on average 14 percent lower in any given year through 2035.

Natural gas prices at other upstream supply points, including Algonquin Citygate

Although Henry Hub is the U.S. natural gas price benchmark, prices vary greatly across the nation. Conditions such as local production, pipeline capacities, storage availability, and demand variability are some of the many factors that cause this variation. Over the past few decades, most supply and consuming regions developed gas hubs, which are liquid pricing points where gas is bought and sold for immediate or future delivery. There are many hubs in the Northeast, but the critical question is which ones determine New England natural gas prices?

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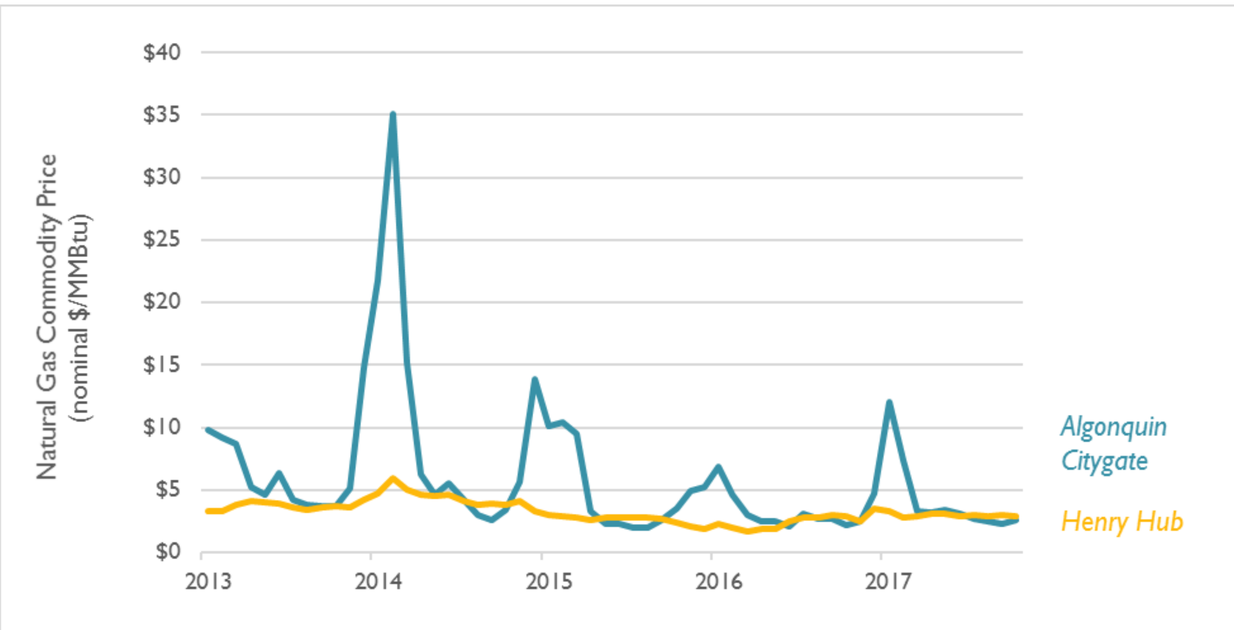
[12] Source: CME. Downloaded 10/18/2017 at 4:00 PM PDT.

[13] We use the NYMEX NG futures final prices dated November 7, 2017 at 4:00 PM EST to forecast Henry Hub prices.

With no indigenous production, New England natural gas is transported by pipeline or imported in the form of LNG. The pipeline shippers purchase natural gas at various supply or market hubs. This natural gas may be sourced from the U.S. Gulf Coast, Midwest, Appalachia, and both Eastern and Western Canada; however, production in the the Marcellus/Utica is outstripping natural gas consumption in the Northeast. As a result, the physical source of New England pipeline gas is increasingly from this nearby basin even if shippers are purchasing gas at distant supply basins (Gulf Coast, Western Canada, Permian Basin, etc.).[14] Thus the price at hubs that source Marcellus/Utica gas is increasingly relevant to New England.

For monthly prices at the Algonquin Citygate and hubs upstream of New England, AESC 2018 applies the same methodology used for NYMEX Henry Hub prices. That methodology relies on NYMEX futures for monthly gas prices over the next two years as well as historical monthly basis. We then apply the trends in average monthly prices to our longer-term projections. See Figure 3 for a historical comparison of gas prices at Algonquin Citygate and Henry Hub.

Figure 3. Historical comparison of natural gas prices at Algonquin Citygate and Henry Hub



AESC 2018 also incorporates monthly prices for Dawn Ontario and Marcellus, using a similar methodology as our projection for the Algonquin Citygate basis. While often correlated, natural gas prices at each hub will vary, depending on supply, demand, pipeline capacity, transport costs, and other conditions. Similar to Henry Hub, there are trading platforms for some of the upstream hubs that may influence the New England natural gas market. For example, NYMEX trades Dominion South basis, Texas

[14] Since natural gas is fungible, interstate pipelines can displace gas anywhere it enters or leaves the system.

Eastern Zone M-3 (TETCO M3), and Transcontinental Gas Pipeline - Zone 6 (Transco-Z6). Natural Gas Intelligence (NGI) publishes prices for the Dawn Hub.[15] In most cases there is also a futures market of varying length at these hubs.

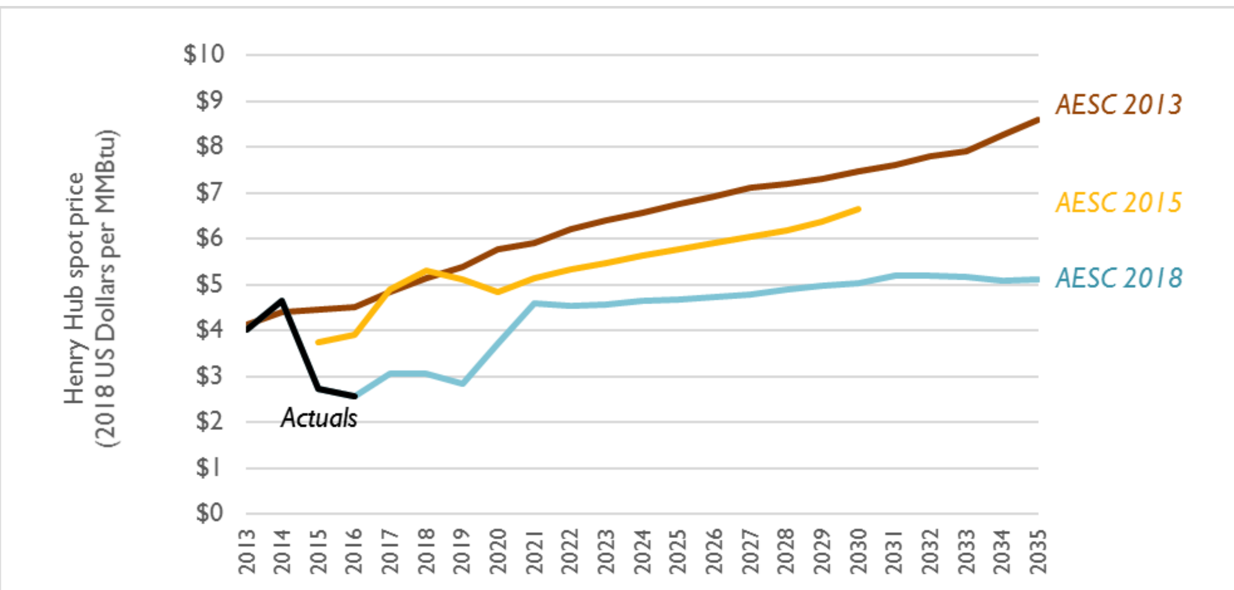
AESC 2018 uses regressions of historical prices to determine which set of price hubs provide the best source for determining marginal gas supply sources for each New England region**.** For monthly prices at the relevant hubs, we apply the same methodology we use for NYMEX Henry Hub prices as described above. AESC 2018 incorporates historical monthly basis data for these pricing points as well as futures, allowing us to apply the trends in average monthly prices to our longer-term projections.

Note that these price forecasts implicitly assume that no large-scale pipeline expansion projects will impact monthly basis, other than ones under construction or slated to be constructed over the next several years. Nor do these natural gas price forecasts take into account possible annual or seasonal changes to natural gas prices resulting from changes in natural gas demand (such as those caused by increased renewables, new imports, or increased energy efficiency).

2.3. AESC 2018 Natural Gas Price Compared to Previous AESC Studies

Figure 4 compares the Henry Hub price forecast in AESC 2018 with the Henry Hub price forecast used in AESC 2013 and AESC 2015.

Figure 4. Henry Hub gas price forecast used in previous AESC studies and AESC 2018



[15] For NGI details on the Dawn hub see: http://www.naturalgasintel.com/data/data_products/forward-contracts?location_id=MCWDAWN&region_id=midwest.

AESC 2013 included price adjustments to the AEO 2012. The AESC 2015 projection did not make similar adjustments.[16] Instead, AESC 2015 assumed that the recent "EIA Annual Energy Outlooks take into consideration the relevant regulatory and other structural components needed to forecast avoided costs of gas in New England."[17] AESC 2018 adopts the same logic to price forecasts as AESC 2015.

Comparision of long-term natural gas price forecast for Henry Hub

In prior AESC studies, EIA's AEO has typically been used to project long-term Henry Hub prices. While AEO forecasts have varied considerably, the assumptions used in the NEMS model are chosen by industry and government experts and are based on a consensus of current and future conditions (see Figure 5).

Figure 5. Comparison of AESC Henry Hub prices

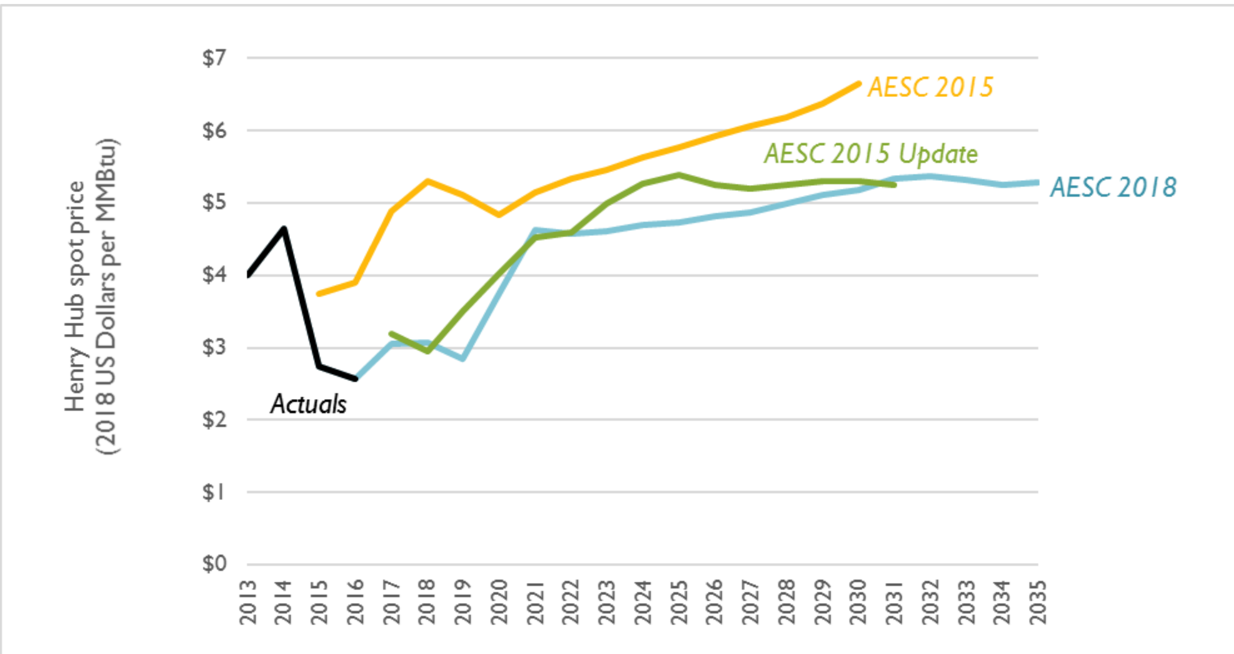


Table 4 compares the levelized prices for natural gas in AESC 2018 with comparable prices forecast in AESC 2015. To provide a rationale for the differences in the projections, this section discusses differences in methodologies, market conditions, and model assumptions.

[16] AESC 2013. Pages 2-7 and 2-8.

[17] AESC 2015. Pages 2-32

Table 4. Comparison of long-term natural gas prices

Study and levelization period	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2015 (2016–2030)	2018 $/MMBtu	$5.44	$6.23	$0.80
AESC 2015 Update (2017–2031)	2018 $/MMBtu	$4.62	$5.55	$0.93
AESC 2018 (2018–2032)	2018 $/MMBtu	$4.38	$5.39	$1.01
Change from AESC 2015 to AESC 2018	%	-19.4%	-13.6%	-
Change from AESC 2015 Update to AESC 2018	%	-5.2%	-2.9%	-

- **AESC 2015:** In AESC 2015, levelized Henry Hub natural gas prices average $5.44/MMBtu (2016–2030), 19.4 percent higher than AESC 2018. Some of the factors that may have contributed to a higher price track include assumptions of a smaller volume of technically recoverable reserves, higher production costs during the first few years of the shale revolution, and a price track that has averaged about $4.00/MMBtu since 2010 (AEO was published in April 2014).

- **AESC 2015 Update:** Using AEO 2016, the AESC 2015 Update projected a levelized Henry Hub price of $4.62/MMBtu, about 15 percent lower than the earlier projection, but 5.2 percent higher than AESC 2018. AEO 2016 assumed recoverable reserves about 27 percent higher than AEO 2014 and incorporated higher rates of technological improvements and innovation. Two years of prices below $3.00/MMBtu was a likely driver in this forecast as were industry estimates of lower breakeven costs for surging Marcellus and Utica production.

- **AESC 2018:** This study relies on AEO 2017 for longer-term Henry Hub price forecasts, with a 15-year levelized value of $4.38/MMBtu. Lower long-term prices appear due to higher associated gas production and another downward adjustment in breakeven drilling and operating costs in the major shale and tight gas producing regions.

Determining the reasons behind differences in natural gas price projections made at different times by different models and forecasters is an imprecise exercise. We have previously commented that NYMEX Henry Hub Futures change continually as thousands of buy/sell decisions are made daily by producers, consumers, hedgers, speculators, and other traders. At a given point in time, we can look back at price history to see if there are analogs to current fundamentals (supply, demand, inventories, etc.), but market expectations are at best an educated guess. For price forecasting models, we can often compare assumptions. However, many price models contain exogenous variables and make changes that are often difficult to detect.

Comparison of medium-term natural gas price forecast for Henry Hub

The methodologies used to forecast the Henry Hub price have been similar over the past several AESC studies in that NYMEX Henry Hub Futures were adapted for early-year projections and prices in the current AEO were used for longer-term forecasts. NYMEX futures represent a current unbiased estimate of Henry Hub prices and have formed the basis for estimating the first two years of the AESC price projections in the past. However, existing market conditions (past and recent prices, production and demand trends, etc.) continually affect the market. The conditions that underpin the first two years of the AESC 2015, AESC 2015 Update, and AESC 2018 Henry Hub prices forecast are as follows:

- **AESC 2015:** NYMEX Henry Hub futures prices dated December 14, 2014 were used in AESC 2015. NYMEX futures projected 2015–16 prices of $3.71 and $3.94 per MMBtu, respectively.[18] These prices were considered bearish relative to the recent past (the prior five-year average was more than $4.00 per MMBtu) and conventional wisdom centered on a breakeven price of at least $4.00/MMBtu in most of the growing production basins. This bearish outlook was the result of a market that was seeing rapid production growth and record-high summer storage injections. Beyond 2016, the market expected prices to again exceed $4.00/MMBtu.

- **AESC 2015 Update:** In the AESC 2015 Update, NYMEX futures prices dated September 27, 2016 were used to forecast Henry Hub prices from 2017 to 2021, resulting in an average price of $3.64 per MMBtu over this five-year period versus $5.06/ MMBtu in AESC 2015.[19] The comparable forecast in AESC 2018 is $3.47/MMBtu. The Fall 2016 price outlook was characterized by a tightening demand-supply balance due to a combination of higher demand for natural gas for electricity generation, a lower-than-normal inventory build, and declining production growth.

- **AESC 2018:** The November 7, 2017 NYMEX Henry Hub futures used in AESC 2018 reflected a summer with below-average storage growth and perennial expectations of a colder-than-normal winter. The 2018 NYMEX average price of $3.06/MMBtu was the highest annual price since 2015. A weaker NYMEX 2019 futures price ($2.96/MMBtu) was likely predicated on strong production growth expectations that have the potential to overwhelm demand increases.[20]

AESC 2018 uses a methodology to forecast monthly Henry Hub prices that mostly parallels the approach used in AESC 2015. AESC 2018 uses actual 2017 and near-term monthly NYMEX Henry Hub futures (to 12/2019) to derive monthly factors (ratio of the monthly price to the annual average). These factors are applied to the annual prices in the AEO 2017 Reference case. For AESC 2015, the monthly projections used the actual factors observed in each of the 12-year NYMEX futures series (through 2027) and applied the monthly NYMEX price variation in the final year to the subsequent AEO annual price projections from 2028 to 2031.

[18] All natural gas prices are expressed in 2018 dollars per MMBtu, unless otherwise noted.

[19] Note that between the initial AESC 2015 NYMEX Henry Hub price projection and the AESC 2015 Update, Henry Hub near-month futures averaged $3.16 and fell to a multi-decade-low price of only $1.64.

[20] Average NYMEX futures price hold below $3/MMBtu through 2025.

The AESC 2018 Henry Hub price forecast reflects gas market conditions and assumptions that differ from the fall of 2015 and 2016. Medium-term prices (the subsequent two calendar years) reflect the current NYMEX futures complex, which embeds recent price history and the expected supply and demand balances.[21] Longer-term prices, as forecast in the AEO 2017 price outlook, reflect changes in assumptions (drilling costs, pipeline infrastructure, resource base, finding-rate parameters, production profiles, productivity and technology changes, regulations and policies, tax rates, oil prices, domestic natural gas demand growth, LNG exports, etc.).

Comparision of New England basis differentials

Previous AESC studies have consistently used NYMEX basis futures as a starting point for forecasting Algonquin Citygate (ACG) prices.[22] Those futures reflect current market expectations—weather, new pipeline construction, etc. However, the methodologies used in previous studies show small differences. For example, AESC 2015 used the current NYMEX over the first two years of the forecast (2015–2017), but it assumed that additional pipeline capacity added after 2017 would reduce winter basis by 40 percent thereafter. The AESC 2015 Update reduced its estimate of new pipeline capacity, raising basis. AESC 2018 uses an average of 2017 actual and 2017–2019 NYMEX basis futures. The levelized basis is higher than the previous projections because it appears to convey current expectations that little new pipeline capacity will be added after 2019.

2.4. New England Natural Gas Market

Background

Natural gas consumption

The EIA reports that 2.4 Bcfd of natural gas was delivered to consumers in the six New England states in 2017 (see Figure 6). Residential customers accounted for 23 percent, commercial and industrial customers used 35 percent, and electricity generators consumed the remaining 42 percent. Gas deliveries in 2017 were 11 percent higher than in 2007, with most of the growth occurring in the commercial sector.

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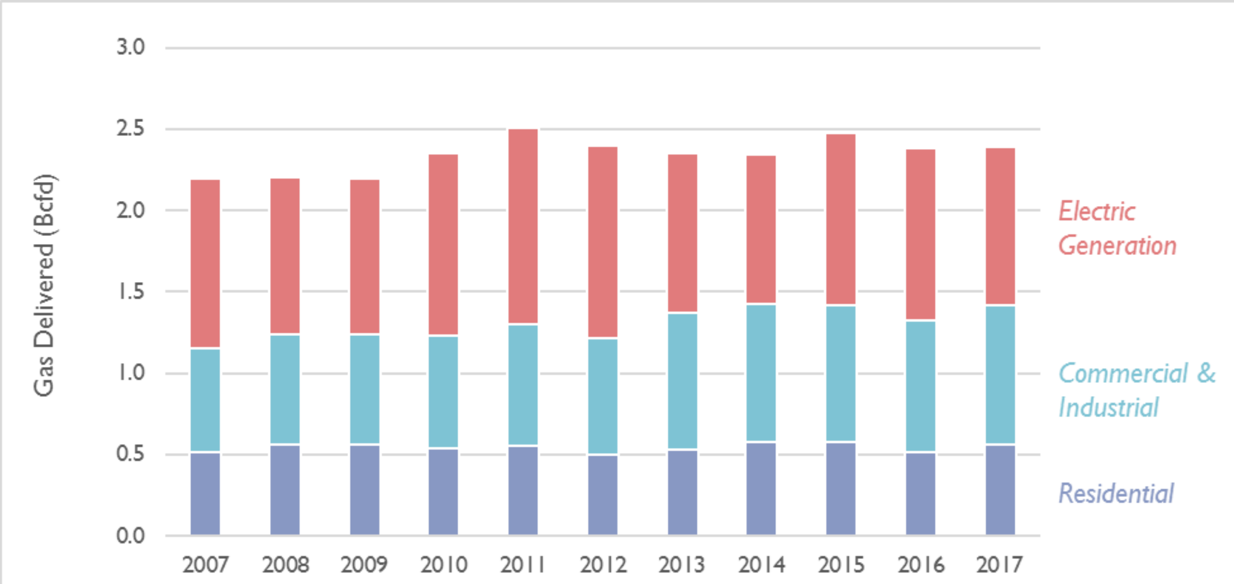
[21] Implicitly, the NYMEX price sends signals to gas producers and consumers to continue or change their behavior. Weak prices are a signal to reduce production and increase consumption and vice versa. However, if the price signals are acted upon, future conditions and gas prices will be different.

[22] Consultation with Vermont Gas resulted in a different methodology for estimating basis for Dominion South (Marcellus) and Dawn. Over the 2020-2035 period, AESC 2018 uses the 2019 futures for Dominion and Dawn; ($0.54) and ($0.20), respectively.

Figure 6. Natural gas delivered to consumers in New England by year

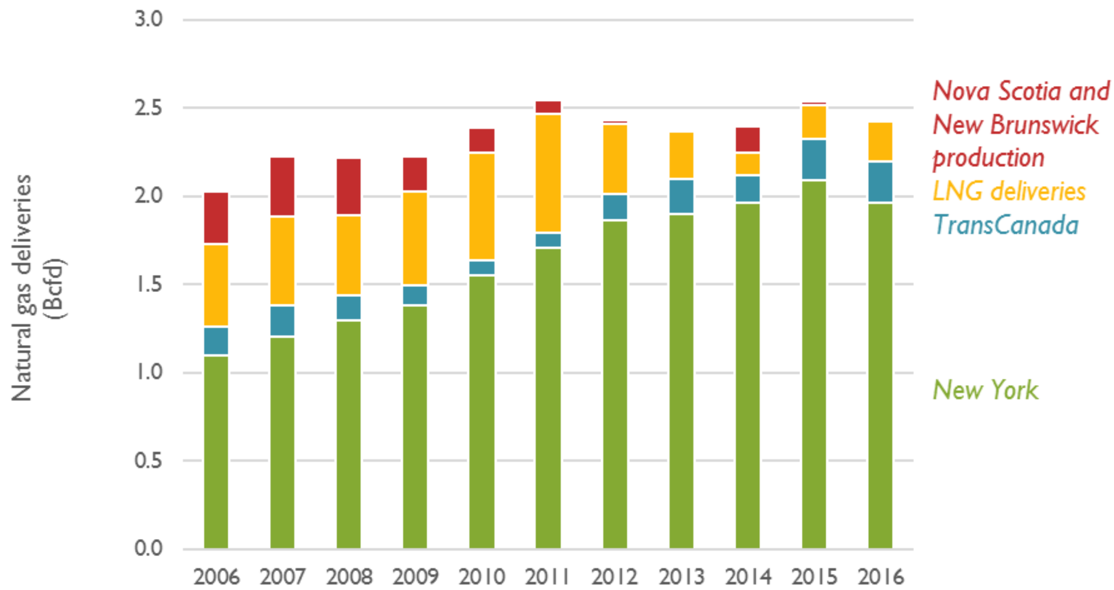


Source: https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm.

New England gas supplies

The sources of natural gas delivered into the New England market have changed in recent years. The principal factors have been the growth in Marcellus Shale gas production, the decline in offshore Nova Scotia gas production, and the reduction in LNG imports. The change in the composition of the gas supplies entering New England is shown in Figure 7. Gas received from pipelines that enter New England from the west (via New York) nearly doubled between 2006 and 2015, while gas produced in the Maritimes provinces has dropped to almost nothing. Gas received from LNG import terminals in Massachusetts and New Brunswick declined sharply from 2011 to 2014 but were somewhat higher in 2015 and 2016. Gas received from TransCanada pipelines at the Vermont and New Hampshire borders has increased since 2011.

Figure 7. Natural gas delivered into New England by year



New England gas supply infrastructure

Tennessee Gas Pipeline and Algonquin Gas Transmission were the first interstate pipelines to supply natural gas to the region, and these two companies still operate most of the high-pressure transmission pipelines in Connecticut, Massachusetts, and Rhode Island. Three more major pipeline systems entered service between 1992 and 2000. One onshore LNG terminal and two offshore LNG receiving facilities are located in Massachusetts. The gas delivery infrastructure that currently brings natural gas into New England is described below and in Figure 8.

<u>Pipelines</u>

Tennessee Gas Pipeline (TGP): The TGP system extends from Texas to New Hampshire. Two branches of the TGP system supply New England. The TGP 200 Line enters western Massachusetts from upstate New York and extends into the Boston area. The TGP 300 Line enters southwestern Connecticut at Greenwich and connects to the 200 Line near Springfield, MA. In addition to these two mainlines, TGP operates lateral pipelines that transport gas into Rhode Island and New Hampshire. The Connecticut Expansion project increased TGP capacity from Wright, NY to Connecticut markets by 0.072 billion cubic feet per day (Bcfd) in late 2017.

Algonquin Gas Transmission (AGT): The AGT system begins at a connection with Texas Eastern Transmission in Lambertville, NJ. AGT also receives gas from TGP at Mahwah, NJ and from Millennium Pipeline at Ramapo, NY. AGT delivers gas in Connecticut, Rhode Island, and Massachusetts. In 2003 AGT built a 25-mile undersea pipeline extension (the “HubLine”) from Weymouth, MA to Salem, MA. The

Algonquin Incremental Market (AIM) project expanded the capacity of the AGT mainline into New England by 0.342 Bcfd. The AIM expansion was completed in January 2017.

Iroquois Gas Transmission System (IGTS): IGTS, which entered service in 1992, connects with the TransCanada PipeLines system (TCPL) at Waddington, NY. IGTS crosses the southwestern corner of Connecticut before terminating in Long Island and New York City. IGTS has interconnections with TGP at Wright, NY (near Albany) and with AGT at Brookfield, CT. Direct deliveries from IGTS into New England are constrained by the capacity of Connecticut LDCs and power generators to receive gas at IGTS meters, and by competition for firm pipeline capacity from downstream markets in New York.

Portland Natural Gas Transmission System (PNGTS): PNGTS, which began operating in 1999, receives natural gas from TCPL at the New Hampshire-Quebec border. PNGTS delivers gas in New Hampshire and Maine, and it terminates at an interconnection with TGP at Dracut, MA. The C2C Project restored the end-to-end capacity of the PNGTS mainline to 0.210 Bcfd in late 2017 by increasing the minimum gas receipt pressure at the Canadian border. PNGTS, in conjunction with TCPL, has also proposed the Portland XPress expansion project, which would provide additional transportation capacity from the Dawn Hub in Ontario.

Maritimes & Northeast Pipeline (M&N): M&N was built in 1999 to transport gas produced in offshore Nova Scotia. The U.S. portion of the M&N system extends from the Maine-New Brunswick border to northeastern Massachusetts. M&N connects with PNGTS at Westbrook, ME, with TGP at Dracut, MA, and with AGT at Salem, MA. In 2009, M&N began receiving gas from the Brunswick Pipeline, which is the outlet for the Canaport LNG terminal at St. John in New Brunswick.

LNG Terminals

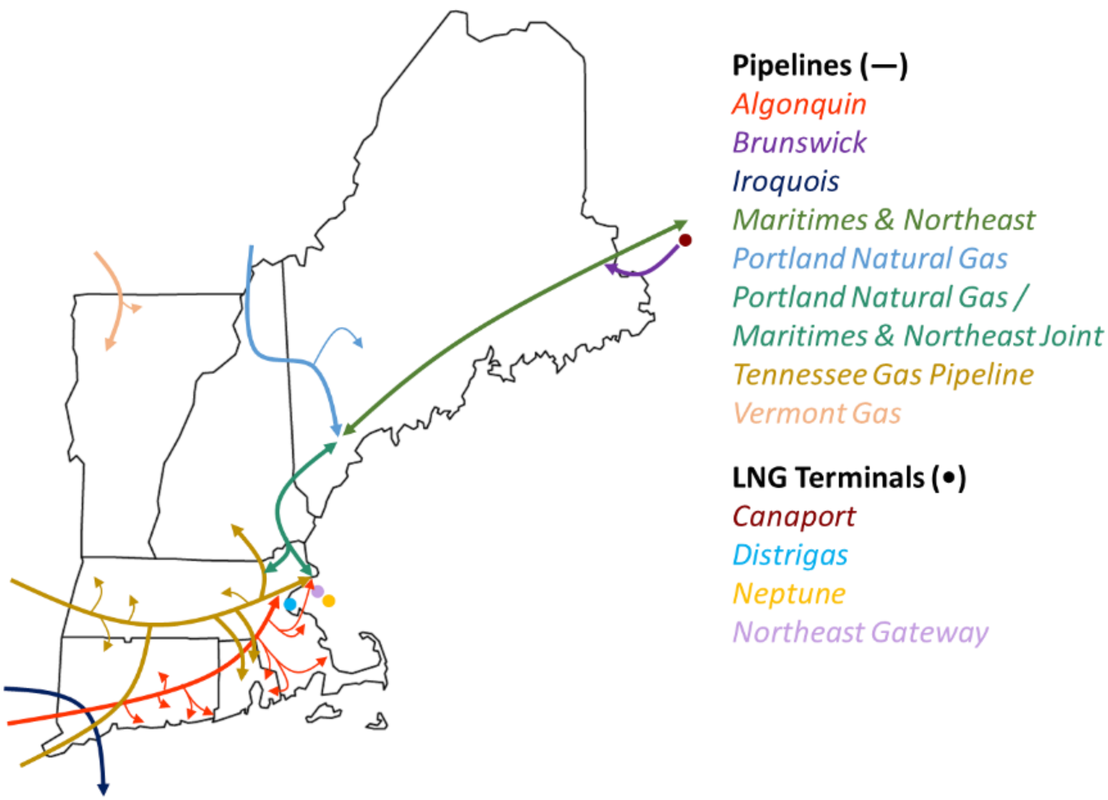
Distrigas of Massachusetts: The Distrigas LNG terminal, located in Everett, MA, has operated since 1971. The terminal is currently owned by ENGIE Gas & LNG. Distrigas delivers gas into TGP, AGT, and the National Grid distribution system, and it is the sole source of fuel for the 1,500 MW of gas-fired generating capacity at Mystic units 8 and 9. LNG is also transported by truck to gas peaking facilities located throughout the region.

Northeast Gateway: Northeast Gateway is an offshore LNG-receiving facility connected to the AGT HubLine pipeline. Northeast Gateway began operating in 2008, but it has received only a few winter-season shipments in recent years.

Neptune LNG: Neptune is a second offshore LNG-receiving facility that feeds into the AGT HubLine. The Neptune facility has not operated since it was completed in 2010.

Canaport LNG: While the Canaport LNG terminal is not located in New England, a single-purpose pipeline connects the facility to M&N at the Maine-New Brunswick border. Canaport, operated by Repsol, has close to 10 Bcf of storage capacity and can send out approximately 1 Bcfd.

Figure 8. New England's natural gas pipeline infrastructure



Source: Synapse Energy Economics, Inc.

The total gas delivery capacity into the New England market is shown in Table 5. The October 2016 estimates are taken from a recent study commissioned by ISO New England, adjusted for the gas that Vermont Gas Systems receives from TCPL.[23] As of January 2018, the total gas delivery capacity into New England is approximately 5.3 Bcfd. This includes the capacity created by the AGT AIM, TGP Connecticut Expansion, and PNGTS C2C projects during 2017. West-to-east pipeline capacity connected to upstream gas production and underground storage is approximately 3.5 Bcfd. Another 0.3 Bcfd can be received from TCPL via Quebec. The remaining 1.5 Bcfd of gas delivery capacity is dependent on gas supply from the Distrigas and Canaport LNG import terminals.

[23] ICF International, "Forecast of Near-term Natural Gas Infrastructure Projects," October 3, 2016.

Table 5. Natural gas delivery capacity into New England (Bcfd)

	OCT 2016	JAN 2018
Algonquin	1.44	1.82
Tennessee	1.32	1.39
Iroquois	0.26	0.26
West-to-East	**3.02**	**3.47**
PNGTS	0.19	0.21
Vermont Gas	0.07	0.07
TCPL Direct	**0.26**	**0.28**
Maritimes	0.83	0.83
Distrigas	0.70	0.70
LNG-Dependent	**1.53**	**1.53**
Total	**4.81**	**5.28**

Planned and potential gas pipeline projects

Table 6 summarizes the natural gas pipeline expansion projects that are currently in active development or under consideration. The next phase of the Atlantic Bridge project and the Portland XPress expansion would add 0.15 Bcfd of pipeline capacity into New England by the end of 2020.

Table 6. Planned and potential pipeline projects delivering gas into New England

	Capacity (Bcfd)	Description	Status
Atlantic Bridge	0.133	Expand AGT mainline to provide service from Ramapo, NY into M&N at Salem.	Began partial service in late 2017, with full service planned in 2018.
Portland XPress	0.050	Add compression to the PNGTS mainline and expand TCPL from Dawn.	Precedent agreements signed. Phased in-service from 2018 to 2020.
Access Northeast	0.925	Expand AGT mainline by 0.525 Bcfd. Eversource would build a 6.8 Bcf, 0.4 Bcfd LNG facility in Acushnet, MA.	Activity suspended in early 2017.

Table 7 describes upstream pipeline projects that would improve access to gas supplies from the Marcellus and Utica shale gas producing areas for the New England market.

Table 7. Planned and potential pipeline projects, upstream of New England

	Capacity (Bcfd)	Description	Status
Vaughan Mainline Expansion	0.041	Expand TCPL delivery capacity to Vermont Gas and PNGTS.	New services to start in 2017 and 2018.
Millennium Eastern System Upgrade	0.223	Expand Millennium pipeline from Corning, NY to Ramapo, NY.	FERC certificate issued 7/29/2016. Planned 9/1/2018 in-service.
Constitution Pipeline	0.650	New pipeline from Susquehanna Co., PA to interconnects with TGP & Iroquois at Wright, NY.	FERC certificate issued 12/2/2014. On hold pending NY State permits.

New England LDC supply portfolios

LDCs obtain gas supply resources for the customers that make up the utility's planning load. Planning load customers include firm sales customers, and firm transportation service customers that are either eligible for capacity assignment, or for whom the LDC has a "supplier of last resort" obligation.

To meet their firm customer requirements, LDCs typically maintain a portfolio of gas supply resources that includes long-term contracts with pipeline and gas storage operators, and on-system LNG and propane-based peaking gas facilities. Resources that are commonly held by New England LDCs include:

- Contracts for pipeline capacity from gas producing areas, such as the Marcellus Shale gas region in Pennsylvania;
- Contracts for pipeline capacity from intermediate gas storage and trading hubs, such as the Dawn Hub in southern Ontario;
- Contracts for pipeline capacity from trading points within the New England market area, such as Dracut and Salem, MA; and
- Contracts for winter season gas supply delivered at the LDC citygate.

LDC resource planning considers peak day, winter season, and annual gas requirements under extreme, "design" conditions. Based on a review of recent LDC resource plans and other public sources, we found that New England LDCs as a group expect to meet about 60 percent of their design day requirements using pipeline capacity from supply points outside of New England (see Table 8). Eight percent would be supplied by gas purchased within New England and either transported using short-haul pipeline capacity, or purchased directly at the LDC citygate. The remaining third of the LDCs' design day supply comes from LNG and propane peaking facilities located within New England.

Table 8. New England LDC design day resources, 2017–18 winter (Bcfd)

	Bcfd	Percent
Pipeline Capacity into New England	2.84	60%
Gas Purchased within New England	0.39	8%
LNG and Propane Peaking Supply	1.49	32%
Total Design Day Supply	4.72	100%

The composition of New England LDC supply portfolios varies by region. LDCs in Southern New England (Connecticut, Rhode Island, and Massachusetts) tend to have more pipeline capacity from outside the market area, while LDCs in Northern New England (New Hampshire and Maine) are more dependent on gas purchased within New England. Northern New England LDCs also have less supply from LNG and propane for peak periods. Vermont Gas is supplied from the Canadian pipeline system, with supplemental supply from an on-system propane peaking facility.

Demand growth and pipeline capacity requirements

Our review of the resource plans of the 13 largest New England LDCs indicates that most LDCs will need to acquire additional gas supply resources during the AESC 2018 forecast period (see Table 9). For the 2017–18 winter season, five of the 13 LDCs estimated that their design day planning load requirements exceeded the capacity of the long-term resources in their supply portfolios. These utilities planned to make up the difference using winter season contracts for citygate-delivered supply.

If gas requirements continue to grow at the currently projected rates, more than half of the 13 LDCs will have a design day supply deficiency within five years, and nearly all LDCs will need additional firm resources within the next decade. The shortfall is estimated to be about 0.3 Bcfd in 2022–23 and 0.8 Bcfd in 2027–28. Several LDCs plan to fill a portion of their design day supply shortfall by expanding on-system peaking capacity, or contracting for LNG supply and short-haul pipeline services. Some LDCs, particularly Northern New England LDCs connected to M&N, are likely to continue to buy significant amounts of citygate-delivered gas. The remaining requirements will need to be met with pipeline capacity from outside New England. If New England LDCs in aggregate continue to hold pipeline capacity from outside the region to meet about 60 percent of their design day requirements, the LDCs' demand for additional pipeline capacity could exceed 0.5 Bcfd within 10 years.

Table 9. Potential design day deficit (MDth)

	2017–18	2022–23	2027–28
National Grid (MA)	23.7	289.0	414.4
NSTAR Gas	10.6	7.4	57.0
Columbia of MA	-	-	-
Liberty (MA)	14.4	12.4	12.0
Berkshire Gas	14.5	3.3	4.9
Fitchburg Gas	-	-	-
National Grid (RI)	-	11.3	38.6
Yankee Gas	-	25.4	115.0
CT Natural	-	-	45.4
Southern CT	-	-	40.3
Liberty (NH)	-	16.4	40.8
Northern Utilities	47.0	59.3	76.4
Vermont Gas	-	-	-
Total	**100.2**	**324.4**	**844.7**

2.5. AESC 2018 Avoided Natural Gas Cost Methodology

Avoidable gas supply costs

The avoided cost is the change in total gas supply cost resulting from a reduction in natural gas use. The total gas supply cost generally includes four components:

(1) the market price of gas at the point of purchase;
(2) the fixed costs of the pipeline, storage, and peaking resources that deliver gas into the local distribution system;
(3) the variable costs to transport gas by pipeline and cycle gas through storage and peaking facilities; and
(4) the cost of delivering gas through the gas distribution system ("retail margin").

For an LDC, the total gas supply cost will depend on the resources in the utility's portfolio. Supply resources can be categorized as baseload, intermediate, or peaking. Baseload resources, such as pipeline capacity that extends from outside the local market area, tend to have a relatively high fixed cost, but a lower variable cost. This type of resource is best suited to supplying high load factor customers that consume gas at a relatively constant rate throughout the year. Peaking resources, such as on-system LNG, typically have lower fixed costs but higher variable costs. These types of resources are a better fit for gas requirements that occur on only a limited number of days per year.

The avoided cost also depends on the characteristics of the gas requirement that is reduced, and the costs of the marginal gas supply resources that correspond to each type of load. For example, if the load reduction is limited to commercial and industrial non-heating customers, the avoided cost will typically be the marginal cost of a baseload resource. For residential heating load, on the other hand, the avoided cost is likely to involve a combination of resources, since the variable gas use of residential heating customers causes the LDC to dispatch a wider range of pipeline, storage, and peaking resources to meet the customers' requirements.

Avoided cost estimates also need to account for costs that are not avoidable. For example, LDCs often sign long-term contracts for new services that require a pipeline system expansion. Once the LDC commits to an amount of capacity on the pipeline, the utility is obligated to pay the monthly reservation charge through the initial contract term. Capital expenditures for on-system peaking facilities are another example of costs that are not avoidable once the facilities are built.

Finally, the avoided cost will depend on whether gas supplies are abundant, so that lower gas use allows the LDC to reduce the existing resources in its supply portfolio. Conversely, if gas supplies are tight, a reduction in gas use will cause the LDC to scale back the new resources that it acquires. This distinction is especially important in New England, where the cost of new gas pipeline capacity is much higher than the costs of existing capacity. For example, the cost of transporting gas from the Marcellus Shale producing areas into New England using new pipeline capacity is estimated to be more than eight times the cost of transporting gas over the same route using existing pipeline services.[24]

Avoided cost calculations

The natural gas avoided cost is an "all-in" cost that includes both variable costs and avoidable fixed costs. For AESC 2018 the avoided gas supply costs are calculated by region (Northern New England, Southern New England, and Vermont), for each end-use category. The five end-use categories are residential heating, residential water heating, residential non-heating, commercial and industrial heating, and commercial and industrial non-heating. The avoided costs are calculated at the citygate, without LDC distribution costs, and at the customer meter, with the avoidable portion of the retail distribution margin included.

The methodology used to calculate the natural gas avoided cost generally follows the same process that LDCs use for resource planning. There are four main steps. Step 1 is to identify the gas supply resources that are likely to be "on the margin." The list of potential marginal resources is based on our review of LDC resource plans and other public sources. Step 2 is to calculate what it would cost to use each of these resources to supply different types of loads. For example, a resource that costs $1.00/MMBtu when used as a year-round baseload supply source would cost $2.42/MMBtu as a winter-only resource dispatched 151 days per year (i.e. at 41 percent load factor). Step 3 is to determine the marginal resource that is the least-cost option to supply gas requirements in each defined load segment ("costing period") over the 15-year planning horizon. In Step 4, the avoided cost for each end-use type is calculated as a weighted average of the marginal resource costs over the applicable costing periods.

Marginal gas supply resources

AESC 2018 uses the following marginal gas supply resources for calculating the avoided costs:

1. Dawn Hub

Two new, large pipelines—Rover Pipeline and the NEXUS pipeline—are currently being built to transport Marcellus and Utica shale gas to the Dawn Hub in southwestern Ontario.[25,26] These two new sources of natural gas supply will supplement gas from Western Canada and the Marcellus Shale gas that is currently flowing into Ontario through Niagara. The Dawn Hub is already the primary gas supply point for Vermont Gas, and a significant supply source for other New England LDCs. Several LDCs plan to

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[24] Southern Connecticut Gas Company, "Forecast of Natural Gas Demand and Supply, 2017–2021," CT PURA Docket 16-10-06, p. IV-28.

[25] https://www.roverpipelinefacts.com/

[26] http://www.nexusgastransmission.com/content/project-overview-map

acquire additional pipeline capacity from Dawn through the Portland XPress project.[27] This supply option includes transportation service from Union Gas from Dawn to Parkway (near Toronto), transportation service from TCPL from Parkway to PNGTS, transportation service on PNGTS to Dracut or the LDC citygate (for Northern New England), and transportation service on TGP from Dracut to the LDC citygate (for Southern New England).

2. Dracut & Salem

LDCs in Southern New England are considering additional gas purchases at the two endpoints of the M&N system, with pipeline transportation service from TGP or AGT to deliver gas to the citygate. With offshore production from Nova Scotia expected to end entirely within the next few years, the likely marginal supply source at Dracut or Salem is LNG from the Engie or Canaport import terminals. The commodity cost for gas sourced at Dracut or Salem is the New England wholesale market price plus a premium for firm delivery. The avoided cost also includes the transportation cost to the LDC citygate.

3. Marcellus Producing Area

The AIM and Atlantic Bridge expansion projects provide additional AGT gas transportation service from interconnects with TGP and Millennium Pipeline at Mahwah, NJ and Ramapo, NY. Both TGP and Millennium transport gas from the Marcellus Shale producing areas in Pennsylvania to East Coast markets. Several New England LDCs have also entered into long-term contracts with Millennium to gain more direct access to gas sold within the Marcellus Shale producing areas. We include a generic expansion project from the Marcellus Producing Area via Millennium and AGT as a marginal resource.

4. Delivered Supply

New England LDCs often contract with gas marketers for firm gas delivered at the LDC citygate to supplement their winter season supply. Delivered supply contracts are more prevalent in Northern New England, where producers and marketers control much of the pipeline transportation capacity that supplies the region. The cost of delivered gas is assumed to be the New England wholesale market price, plus a premium for firm citygate delivery.

5. LNG and Propane Peaking

Several LDCs have either undertaken, or are considering, projects to upgrade existing peaking facilities or construct a new LNG facility. To reflect this, we add an expansion cost adjustment to the LNG acquisition cost when calculating the marginal cost of LNG peaking supplies. For Vermont Gas, the peaking supply cost is the propane price, plus the variable operating cost for its existing facility.

The marginal gas supply resources for each New England region are summarized in Table 10.

[27] New England LDCs participating in the Portland XPress project include National Grid (MA), Columbia of MA, Berkshire Gas, Liberty (NH), and Northern Utilities.

Table 10. Marginal gas supply resources by region

	SNE	NNE	VT
Dawn	X	X	X
Dracut/Salem	X		
Marcellus Shale	X	X	
Delivered Supply		X	
LNG Peaking	X	X	
Propane Peaking			X

Costing periods

The annual planning load is divided into six costing periods to reflect the different end-use types that LDCs supply. These include industrial requirements that occur at a high load factor over the year, and heating requirements with a much lower annual load factor. Since most gas supply resources entail significant fixed costs, the load factor at which the resource will be utilized is important for determining which supply resources should be increased or decreased in response to a change in requirements.

The six costing periods are defined as follows:

The "Annual Baseload" costing period includes the portion of the LDC's annual load that occurs at a constant rate throughout the year. The "Winter/Shoulder" period includes gas requirements that occur on all days with heating degree days (HDDs) greater than zero.[28] This costing period is included to separate the base gas use from other high load factor use that varies with temperature. These high load factor requirements are typically supplied with long-haul pipeline capacity that allows the LDC to buy gas closer to the point of production, where prices are generally lower.

The "Winter" costing period includes the portion of the temperature-sensitive load that occurs throughout the November-to-March winter season, and the "Highest 90 Day" costing period captures the gas requirements that occur only during the coldest three months of the year. These types of loads are often supplied using pipeline capacity from an intermediate storage or supply hub. Contracting for pipeline transportation service over a shorter distance generally has a lower annual fixed cost than long-haul service, but the gas prices at points closer to major markets tend to be higher. Gas storage capacity that is filled during the summer and dispatched during the winter is a hedge against price volatility, and it can add flexibility and reliability to winter season gas supply.

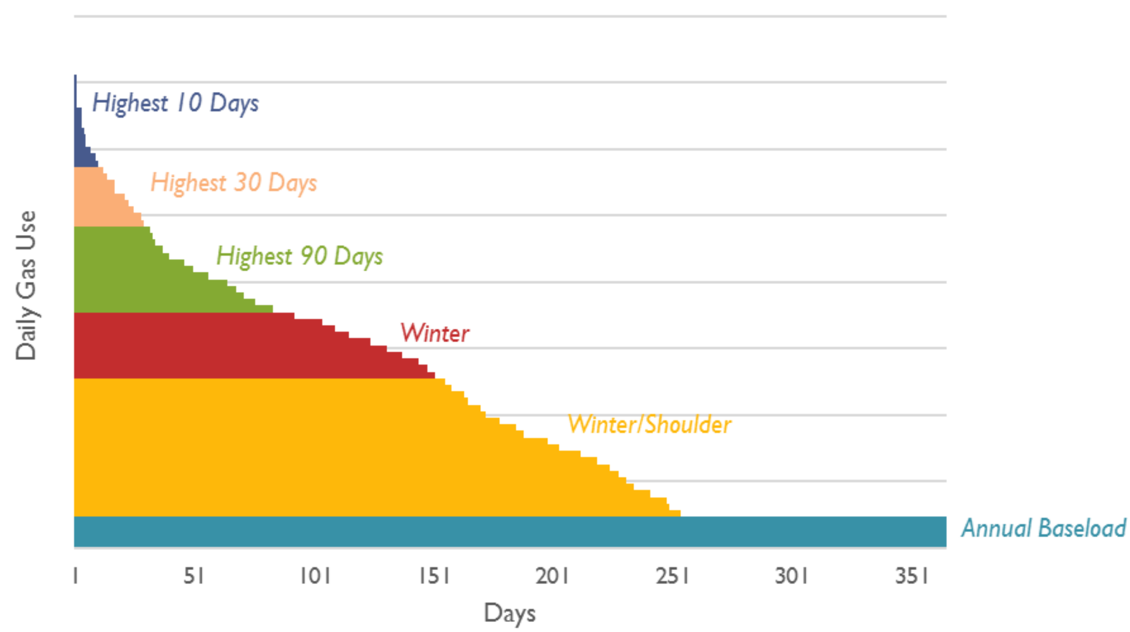
The "Highest 30 Day" and "Highest 10 Day" costing periods correspond to the gas requirements that only occur on the coldest days of the year. These requirements are typically met using market-area

[28] Heating Degree Days (HDD) can be calculated for a single day by subtracting the average outside temperature (e.g., 30°F) from the desired conditioned temperature (e.g., 65°F). HDD can then be summed over multiple days to estimate the total number of HDD (in a month, for example).

purchases and on-system peaking facilities. These resources have lower fixed costs and high variable costs, making them more suitable to meeting low-load factor gas requirements.

Figure 9 illustrates how the costing periods are used to divide the annual load curve into segments.

Figure 9. Load shape example



Annual avoided cost

The annual avoided cost for each end-use category measures the change in gas supply costs that would result from a pro rata reduction in gas requirements over the year. The annual avoided cost is calculated by first multiplying the avoided cost for each costing period by the corresponding load share, and then summing the results.

To determine the portion of the annual gas requirement that falls into each costing period, we use a simple load equation to develop a load shape for each end-use:

Daily Gas Use = Daily Base Use + Use per HDD x HDD

where, HDD is the number of heating degree days in that day.

The Base Use per Day and the Use per HDD factors are applied to a representative daily HDD profile. The load shares by costing period for each end-use type are shown in Table 11.

Table 11. End-use load distributions

Costing Period	Residential			Commercial & Industrial	
	Non-Heating	Hot Water	Heating	Non-Heating	Heating
Annual Baseload	100%	21.5%	0%	68.0%	21.0%
Winter/Shoulder	0%	52.0%	66.0%	21.0%	52.0%
Winter	0%	15.0%	19.0%	6.0%	15.0%
Highest 90 Days	0%	8.5%	11.0%	3.5%	9.0%
Highest 30 Days	0%	2.0%	3.0%	1.0%	2.0%
Highest 10 Days	0%	1.0%	1.0%	0.5%	1.0%

Table 12 provides an example of the annual avoided cost calculation. This is repeated for each end-use category, for each year of the forecast period.

Table 12. Illustrative avoided cost calculation example

Costing Period	Marginal Resource Cost ($/MMBtu)	Share of Annual Gas Use	Weighted Average ($/MMBtu)
	(A)	(B)	(A) x (B)
Annual	$4.00	-	-
Winter/Shoulder	$5.00	60%	$3.00
Winter	$6.00	25%	$1.50
Highest 90 Days	$8.50	10%	$0.85
Highest 30 Days	$15.00	4%	$0.60
Highest 10 Days	$30.00	1%	$0.30
AVOIDED COST FOR THIS END-USE TYPE ➔			**$6.25**

Avoidable LDC margins

AESC 2018 quantifies the natural gas avoided cost for each end-use by sector and the retail sector based on the sum of the avoided cost of the gas sent out by the LDC and the avoidable LDC margin, which is avoidable distribution cost from the citygate to the burner tip.

The LDC margin represents the portion or amount of distribution cost that is avoidable based on reductions in natural gas usage from efficiency measures. The LDC margin will vary by LDC. Some LDCs estimate the amount as their incremental or marginal cost of distribution. In other words, the LDC margin is the change in cost of distribution incurred as demand for gas increases or decreases. The load type and customer sector will influence incremental costs for LDCs. Low load factor or heating loads would have embedded costs that could be incremental or avoidable relative to high load factor or non-heating loads.

AESC 2018 calculates the LDC margin as a percentage of embedded costs through a stepwise process. For the first step, we quantify the difference between the citygate price of gas in a state and the price charged for each of the different retail customer types: residential, commercial/industrial, and all retail customers. Second, we develop a retail cost of gas that is the average distribution cost for Northern and Southern New England regions weighted based on the volumes of natural gas delivered to each sector in each state of the region. Third, we calculate avoidable LDC margin by end-use sector and load type as the product of (a) the retail cost of gas for each region and sector and (b) the avoided margin percentages provided by National Grid from data in Docket DPU 17-170 (2017 National Grid rate case, Boston Gas).[29] The resulting margin is then added to the avoided delivered price of gas to develop the avoided natural gas cost.

For LDCs that do not assume any avoidable distribution costs associated with reduction from efficiency programs, the avoided natural gas cost would be the avoided delivered price of natural gas.

Natural gas avoided costs: Vermont

Vermont-specific natural gas avoided cost estimates are developed for four time-of-use costing periods: (1) Design Day; (2) Peak Period; (3) Remaining Winter; and (4) Rest of Year. The Design Day avoided cost is the supply cost savings that would result from reducing gas use on the peak day. The Design Day avoided cost is the sum of (a) the Marginal Upstream Transmission cost, (b) the Marginal Downstream Transmission cost, and (c) the winter-season gas commodity and variable transportation costs.

The Peak Period avoided costs are the gas supply savings that would result from reducing gas use on the 10 days of highest demand, excluding the peak day. The Peak Period avoided cost is the propane supply cost, plus the variable operating cost for the Vermont Gas propane air peaking facility.

The Remaining Winter is the 151-day winter season (November through March), minus the 10 peak period days. The avoided cost is a weighted average of gas delivered from Dawn storage (80 days), and the variable cost of gas purchased and delivered from the Dawn Hub (61 days).

The Rest of Year costing period corresponds to the months of April through October. The avoided cost is the variable cost of baseload gas supply from the Dawn Hub.

Comparison to AESC 2015

AESC 2015 recommended using three costing periods: the highest 10 days (“peak”), the next highest 141 days (“shoulder”), and the remaining 214 days (“baseload”)—and assigning a specific supply resource to each period.[30] AESC 2018 begins with a larger number of marginal supply types, and then assigns resources to costing periods by identifying the lowest cost option for each type of load. Using more costing periods allows a greater variety of supply resources to enter into the calculation of avoided cost.

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[29] National Grid defines the LDC margin percentage as the fraction of marginal cost to embedded cost.

[30] AESC 2015, Section 2.16.

Other assumptions

Lost and unaccounted-for gas

The total quantity of gas measured at customer meters is generally lower than the measured quantity of gas that the LDC receives into its system because of lost and unaccounted-for gas (LAUF). For New England LDCs, the difference between measured receipts and deliveries is typically between 1 and 3 percent. LDCs apply an estimated LAUF percentage to their customer load forecasts when projecting their gas supply resource needs at the citygate. Based on a review of the LAUF factors reported by New England LDCs, we apply a LAUF factor of 1.5 percent.

Capacity optimization

LDCs offset the fixed costs associated with holding long-term pipeline capacity contracts by releasing capacity into the secondary market or using the capacity to make off-system sales. Overcapacity often results from the fact that pipeline expansions are infrequent and unpredictable, so that LDCs need to contract for more capacity than they currently require. Because the avoided cost methodology assumes that capacity additions (or reductions) can be scaled to match the actual change in gas requirements, we do not make any adjustment to the resource costs for capacity optimization activity.

2.6. Avoided Natural Gas Costs

This section provides a summary of the natural gas avoided costs, including a comparison of natural gas avoided costs as calculated in the 2018 AESC Study to both the 2015 AESC Study and 2015 AESC Study Update.

Avoided natural gas cost by end-use

A summary of the natural gas avoided cost estimates is shown in Table 13 and Table 14. Detailed avoided natural gas costs by end-use and by costing period are presented in *Appendix C. Detailed Natural Gas Outputs.*

Table 13. Avoided costs of gas for retail customers by end-use assuming no avoidable margin

Study	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
Southern New England								
AESC 2015	6.30	6.85	7.03	6.89	6.51	6.86	6.71	6.80
AESC 2015 Update	5.45	6.00	6.18	6.04	5.66	6.01	5.85	5.96
AESC 2018	5.85	7.55	8.08	7.64	6.56	7.58	7.14	7.40
2015 to 2018 change	*-7%*	*10%*	*15%*	*11%*	*1%*	*10%*	*6%*	*9%*
2015 Update to 2018 change	*7%*	*26%*	*31%*	*26%*	*16%*	*26%*	*22%*	*24%*
Northern New England								
AESC 2015	6.30	8.07	8.66	8.19	6.96	8.09	7.60	7.91
AESC 2015 Update	5.44	7.34	7.98	7.47	6.15	7.37	6.83	7.18
AESC 2018	5.65	7.34	7.82	7.40	6.37	7.37	6.93	7.18
2015 to 2018 change	*-10%*	*-9%*	*-10%*	*-10%*	*-8%*	*-9%*	*-9%*	*-9%*
2015 Update to 2018 change	*4%*	*0%*	*-2%*	*-1%*	*4%*	*0%*	*1%*	*0%*
Vermont								
Study	**Design Day**	**Peak Days**	**Remaining Winter**	**Shoulder / Summer**				
AESC 2015 (a)	549.00	22.91	7.88	6.50				
AESC 2015 Update (b)	548.73	23.87	7.08	5.69				
AESC 2018	561.39	26.27	4.89	4.48				
2015 to 2018 change	*2%*	*15%*	*-38%*	*-31%*				
2015 Update to 2018 change	*2%*	*10%*	*-31%*	*-21%*				

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent.

Table 14. Avoided costs of gas for retail customers by end-use assuming some avoidable margin

Study	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL
	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	RETAIL END USES
Southern New England								
AESC 2015	6.95	8.28	8.73	8.53	7.15	8.06	7.74	7.71
AESC 2015 Update	6.08	7.40	7.83	7.64	6.28	7.18	6.85	7.26
AESC 2018	6.18	7.89	9.17	8.58	6.99	8.34	7.75	8.17
2015 to 2018 change	*-11%*	*-5%*	*5%*	*1%*	*-2%*	*3%*	*0%*	*6%*
2015 Update to 2018 change	*2%*	*7%*	*17%*	*12%*	*11%*	*16%*	*13%*	*12%*
Northern New England								
AESC 2015	6.84	9.30	10.12	9.60	7.46	9.04	8.41	8.76
AESC 2015 Update	5.98	8.54	9.38	8.84	6.64	8.28	7.62	8.00
AESC 2018	5.96	7.65	8.83	8.28	6.65	7.88	7.34	7.65
2015 to 2018 change	*-13%*	*-18%*	*-13%*	*-14%*	*-11%*	*-13%*	*-13%*	*-13%*
2015 Update to 2018 change	*0%*	*-10%*	*-6%*	*-6%*	*0%*	*-5%*	*-4%*	*-4%*

Notes: All values are in 2018 $/MMBtu. AESC 2015 levelized costs are for 15 years (2016–2030) at a discount rate of 2.43 percent. AESC 2015 Update levelized costs are for 15 years (2017–2031) at a discount rate of 1.43 percent. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent.

The following figures visualize the comparison between the avoided natural gas costs across AESC 2018, AESC 2015, and AESC 2015 Update.

Figure 10. Natural gas avoided costs: Southern New England (assuming no avoidable margin)

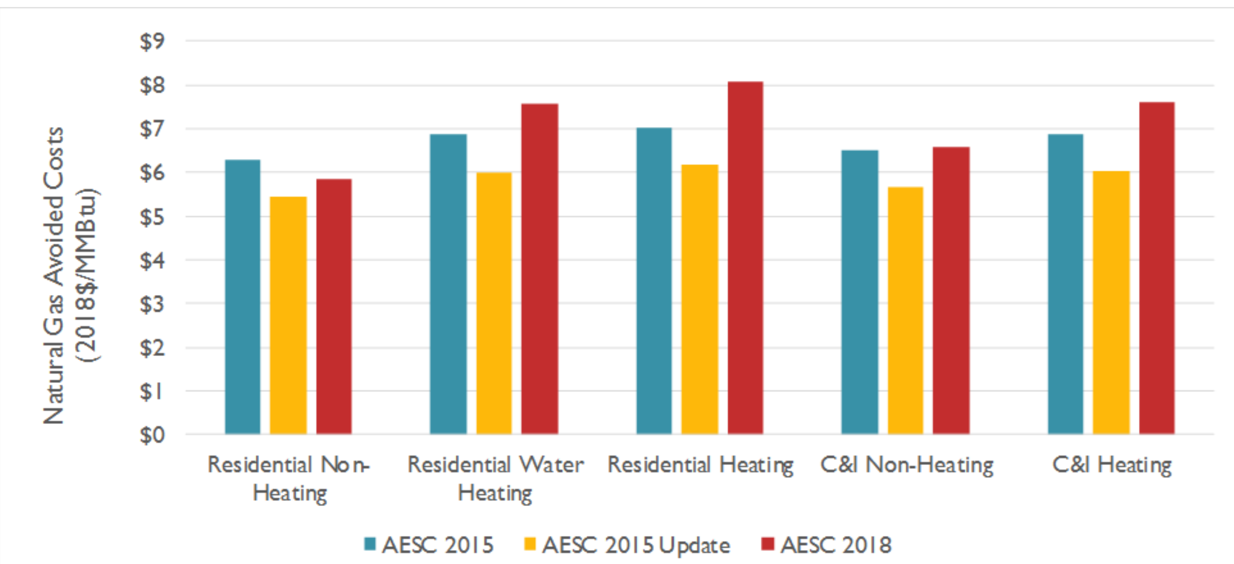


Figure 11. Natural gas avoided costs: Northern New England (assuming no avoidable margin)

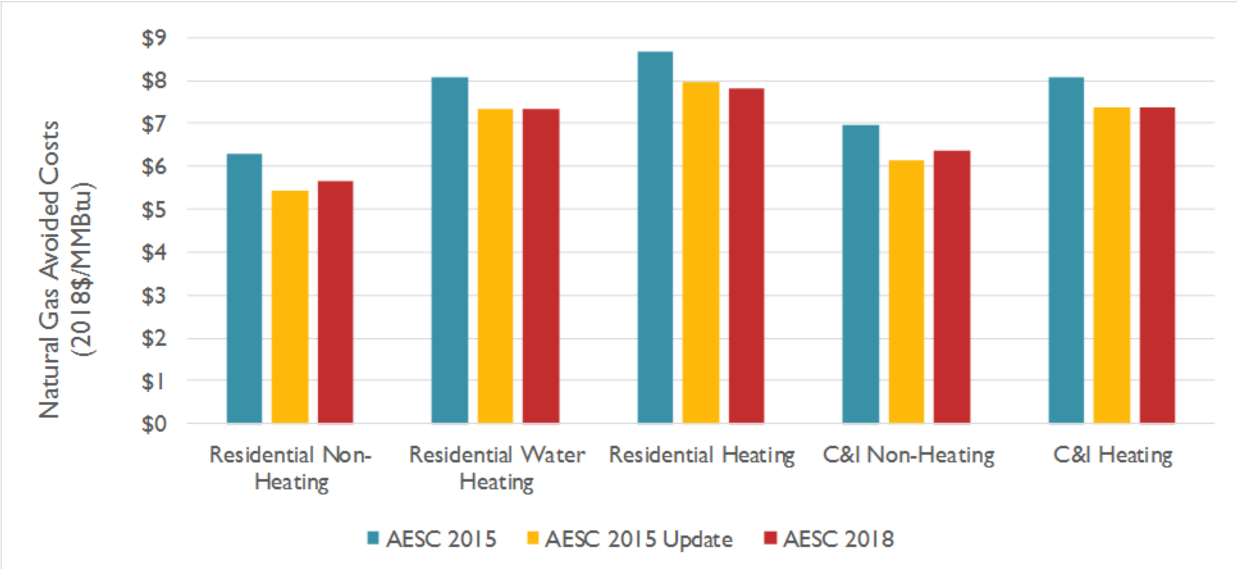
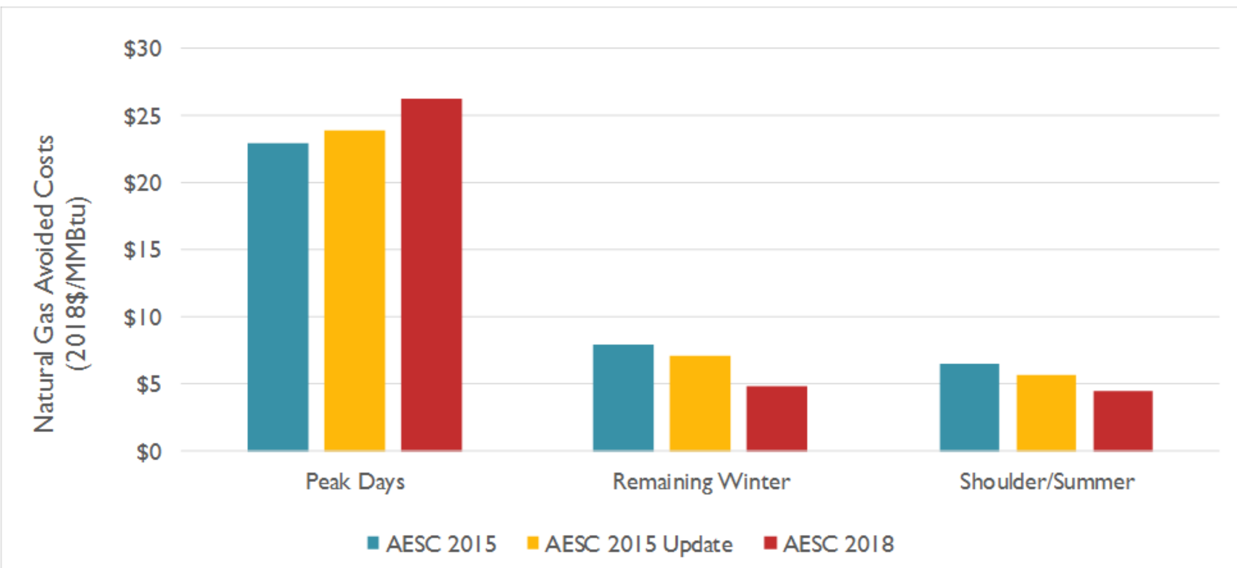


Figure 12. Natural gas avoided costs: Vermont (assuming no avoidable margin)



Comparison to AESC 2015

Southern New England

Even though the Henry Hub and Algonquin Citygate gas price forecasts used for AESC 2018 are lower than the prices used for AESC 2015 and the AESC 2015 Update, the avoided cost estimates for the Southern New England states are generally higher. The main difference is that AESC 2015 assumed a large increase in pipeline capacity into New England during the initial years of the forecast period.

Because LDCs had binding commitments to the Kinder Morgan Northeast Energy Direct (NED) project and other pipeline expansion projects at the time of the AESC 2015 study, the fixed charges for new pipeline capacity were not avoidable. The AESC 2015 avoided costs were therefore based on the tariff rates for existing pipeline services that LDCs could either terminate or renew.

The NED pipeline has been cancelled, and the Access Northeast project is currently on hold. The current expectation is that gas pipeline capacity into New England will remain tight, with incremental expansions of existing pipelines. For AESC 2018, avoided costs include the rates for new pipeline capacity, which are typically higher than the rates charged for existing gas transportation services. Because pipeline operators recover capital costs and most operating costs through the monthly demand charge, the impact of higher incremental pipeline charges is amplified for lower load factor end-uses, such as residential heating.

Northern New England

The avoided costs for Northern New England are generally lower than the avoided costs for the AESC 2015 studies. The AESC 2018 avoided cost is largely driven by market prices at the Dawn Hub and transportation costs from Dawn to Northern New England. The Dawn Hub price basis is expected to decline as a result of new pipeline capacity delivering Marcellus and Utica shale gas into southern Ontario.

Vermont

The natural gas avoided cost estimates for Vermont use the end-use costing periods and methodology that were developed for the AESC 2015 study. The Design Day avoided cost is the marginal upstream supply and delivery cost, plus the marginal LDC transmission cost. The Peak Day avoided cost is the cost of on-system peaking supply, which includes the propane price and the variable operating expense. The avoided costs for the remaining periods are based on the Dawn Hub gas supply and storage costs. Gas purchase costs are lower for AESC 2018 because of the lower Henry Hub forecast and the change in the Dawn Hub price basis. The Design Day avoided cost is higher because the AESC 2015 did not include the estimated variable operating costs for the Vermont Gas peaking facility.

3. FUEL OIL AND OTHER FUEL COSTS

In this chapter, we present the avoided fuel oil and other fuel costs used for AESC 2018, compare those estimates with AESC 2015, and identify the data sources used. In general, we find that avoided levelized costs for residential fuel oil and other fuels are generally higher than was estimated in AESC 2015, while levelized costs for commercial fuel oil is slightly lower than was estimated in AESC 2015. The primary source of this difference is a change in data sources from the previous AESC study. The significant differences from AESC 2015 in propane and wood fuel prices are related to changes in data sources as discussed below.

3.1. Comparison to AESC 2015

Table 15 compares the levelized avoided fuel costs for AESC 2018 compared with those used for AESC 2015. Annual avoided fuel costs are detailed in Appendix D. The avoided costs for AESC 2018 differ substantially from AESC 2015 for propane and wood fuels, and less so for the others. For non-wood products, AESC 2018 starts with the New England fuel prices in the EIA State Energy Data System (SEDS) and escalates prices with the crude oil price forecast. For biofuels, it is priced at a 3 percent premium to distillate as discussed below. All sector propane prices are consistently higher than distillate prices for all years in SEDS (see Table 16). For residential wood fuels, AESC 2018 surveys various state energy sources, which give much higher retail prices than those used in AESC 2015 (although they had been higher in AESC 2013). The prices used in AESC 2015 were mostly based on AEO 2014 which is a secondary source, although generally calibrated to the most recent price data. AESC 2018 has instead relied upon available primary sources whenever possible.

Table 15. Comparison of avoided costs of retail fuels (15-year levelized, 2018 $/MMBtu)

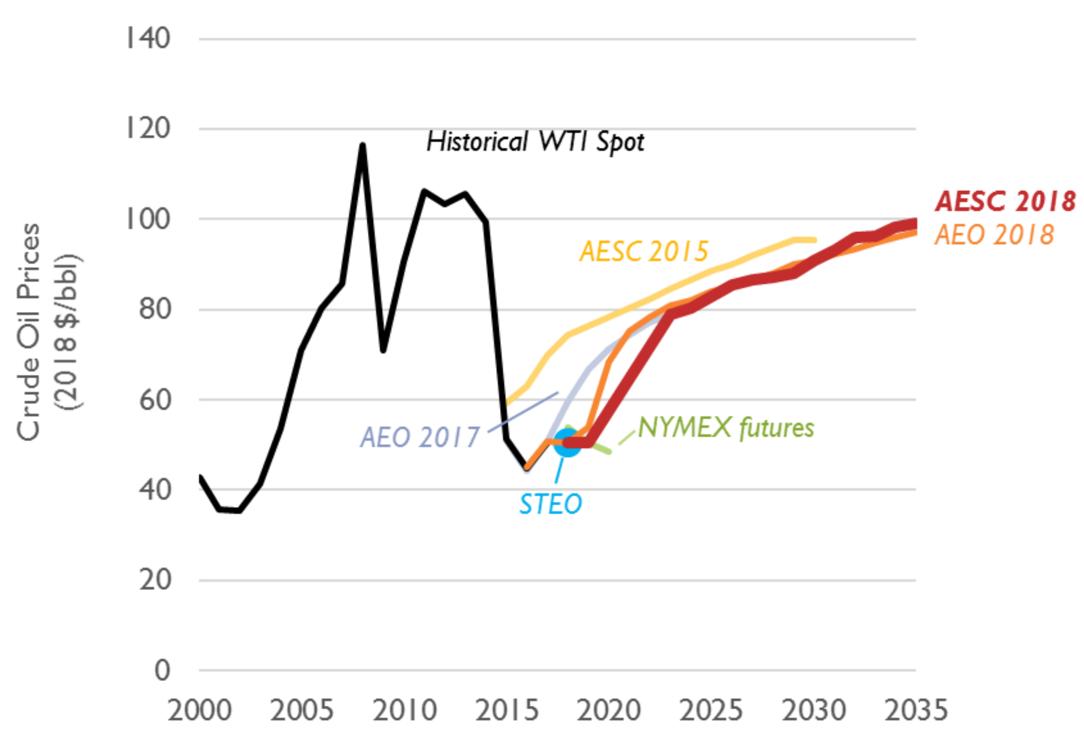
	Residential						Commercial	
	No. 2 Distillate	Propane	Kerosene	BioFuel	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)
AESC 2015 (2016–2030)	$20.15	$19.26	$21.98	$19.61	$7.14	$8.12	$19.63	$17.29
AESC 2015 Update (2017–2031)	$21.22	$19.79	$23.14	$19.61	$7.14	$8.12	$19.87	$17.46
AESC 2018 (2018–2032)	$22.17	$31.11	$19.88	$22.83	$13.40	$21.60	$18.47	$16.26
Change from AESC 2015 to AESC 2018	10.0%	61.5%	-9.6%	16.4%	87.8%	165.9%	-5.9%	-5.9%
Change from AESC 2015 Update to AESC 2018	4.4%	57.2%	-14.1%	16.4%	87.8%	165.9%	-7.0%	-6.9%

3.2. Forecast of Crude Oil Prices

The primary factor driving fuel oil prices is the price of crude oil. For AESC 2018, we use NYMEX forecasts/futures and then the Reference case of AEO 2017, following methodology used in prior AESC studies. AESC 2018 relies on EIA short-term forecasts (STEO) and futures markets (NYMEX) for the near term (two years) and then transitions to the AEO 2017 Reference case projection in 2023.[31]

Figure 13 summarizes the crude oil price projections for the constituent inputs to the AESC 2018 crude oil forecast. When comparing levelized costs, one should consider the different starting years for the AESC reports, i.e., mentally shift the AESC 2015 curve three years forward to 2018.

Figure 13. Crude oil prices, historical, forecast, AESC 2018, and AESC 2015



As shown in Figure 13, there has been significant variability in historical prices that is reflected in the uncertainty in future crude oil prices. In addition to the Reference case, the EIA's AEO 2017 also

[31] AEO 2018 has been released since we did our initial analysis, but the WTI price forecast from 2021 onwards is nearly identical to that of AEO 2017. https://www.eia.gov/outlooks/aeo/data/browser/.

considered some side cases with substantial differences, with prices in 2025 ranging from $25 to $175 per barrel.[32]

We also note that fuel oil use in the residential, commercial, and industrial sectors in New England is substantial and about on par with that of end-use natural gas consumption.

3.3. Base Fuel Prices

AESC 2018 uses information from SEDS to determine the prices of non-wood fuels.[33] The most recent available data is for 2015. This is our starting point and that is then escalated and inflated to AESC starting prices for 2018 and adjusted based on the AESC 2018 crude oil price growth rate.

Table 16 shows the New England SEDS prices for 2015. There are a few key things of note here: (1) the distillate fuel oil (DFO) prices are significantly higher for the residential sector compared to the others, (2) the same is true for liquified propane gas (LPG), and (3) but for kerosene both the residential and commercial sectors have higher prices. The source of these price differentials appears to be the retail price markups to different sectors. The residential sector represents smaller customers and thus higher markups. We also note that the fuel price differentials are consistent in SEDS over the five-year period from 2011 through 2015.

The premium price for LPG compared to fuel oils is present in all the sectors, but greater for residential. Although the cost per gallon for propane is similar to that for fuel oil, the energy content is 34 percent less resulting in a higher energy cost. LPG storage, transport, and handling are also more demanding than for fuel oil.

We have also reviewed the residential distillate fuel oil and LPG prices in the EIA heating fuel data and they are consistent with the SEDS prices.[34] The higher residential DFO starting price is the reason that the levelized AESC 2018 residential fuel oil prices in Table 16 are higher than those of AESC 2015.

Table 16. Weighted average 2015 fuel prices from EIA's SEDS (2015 $/MMBtu)

	Distillate fuel oil (DFO)	Kerosene	Propane (LPG)	Residual fuel oil (RFO)
Residential	18.72	16.79	29.76	NA
Commercial	15.25	16.85	23.28	10.12
Industrial	15.49	15.70	24.00	10.18
Weighted average	17.93	16.70	26.72	10.15

[32] EIA's AEO 2018 prices were not available until February 2018 and are informational only.

[33] For more information, see https://www.eia.gov/state/seds/.

[34] For more information, see https://www.eia.gov/special/heatingfuels/?src=home-b2#/US-MA:oil:week. Data is presented by Petroleum Administration for Defense District (PADD), which are are geographic aggregations of the 50 States and the District of Columbia.

In terms of the AESC grade categories, we used the following mapping: No. 2 grade is distillate fuel oil used in the residential sector, No. 4 is distillate fuel oil used in the other sectors, and No. 6 is residual fuel oil used in the commercial, industrial, and electric sectors. Definition of the EIA fuel oil categories can be found on the EIA website.[35]

The AEO does not provide a forecast of New England regional prices for biofuels B5 and B20, as these blends represent a small portion of the New England market. Both B5 and B20 are mixes of a petroleum product, such as distillate oil or diesel, and an oil-like product derived from an agricultural source (e.g., soy beans). The number in their name is the percent of agricultural-derived component. Thus "B5" and "B20" represent products with a 5 percent and a 20 percent agricultural-derived component, respectively. They are both similar to No. 2 fuel oil and are used primarily for heating. Each of these fuels has both advantages and disadvantages relative to No. 2 fuel oil. Their advantages include lower greenhouse gas (GHG) emissions per MMBtu of fuel consumed,[36] more efficient operation of furnaces, and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents and concerns about the long-term supply of agricultural source feedstocks.

Per ASTM D396, fuel oils for home heating and boiler applications may be blended with up to 5 percent biodiesel below the rack.[37,38] Marketers are not required to disclose information on biodiesel content below these levels. While the AEO forecast for fuel oil does not reflect any inherent biodiesel content, the current price premium for B99-B100 biodiesel is $0.75 per gallon,[39] or an implied 6 cents per gallon for the B5 blend. However, the current price for B20 is just $0.02 per gallon above diesel ($2.49 vs. $2.47). Over the last three years, this premium has averaged 7 cents per gallon. Based on this recent history, we used a 3 percent price premium for B20 above diesel and no premium for B5.

Prices in future years start with the base year prices as indicated and are then adjusted going forward using the changes in crude oil prices.

Table 17 below shows the reference starting values used for the AESC 2018 forecast.

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35 EIA Fuel oil definitions: https://www.eia.gov/tools/glossary/index.php?id=N.

36 The CO_2 emissions from the bio component of the fuel are not counted as contributing to global climate change.

37 ASTM International. "ASTM Sets the Standard for Biodiesel." Jan 2009. Available at: http://www.astm.org/SNEWS/JF_2009/nelson_jf09.html.

38 "Below the rack" refers to blending at the refinery, before fuel is sold to wholesalers.

39 DOE Alternative Fuels Data Center, July 2017 prices. https://www.afdc.energy.gov/fuels/prices.html.

Table 17. Sales-weighted and crude oil price adjusted fuel prices for 2018 (2018 $/MMBtu)

	Residential			Commercial		Industrial	
	Distillate Fuel Oil	Kerosene	Liquified Propane	Distillate Fuel Oil	Residual Fuel Oil	Distillate Fuel Oil	Residual Fuel Oil
AESC Prices	19.42	17.42	30.89	15.83	10.51	16.07	10.56

Wood fuels

The residential wood fuel prices in EIA SEDS are based on old data surveys and do not appear to be consistent with more recent sources. We instead contacted a number of New England state agencies who provided us with information about current wood prices. The prices for wood pellets ranged from $256 to $275 per ton (see Table 18).[40] Cord wood prices were between $200 to $250 per cord. The local range may be greater, but we recommend an average of these public values.

Table 18. New England retail residential wood prices

	Wood Pellet		Cord Wood
State	Bulk	Bagged	Bulk
CT	N/A	N/A	N/A
MA[41]	$256/ton	$260/ton	N/A
ME[42]	$258/ton		$250/cord
NH[43]	$269/ton	$269/ton	$200/cord
VT[44]	$275/ton		$227/cord

Thus, for wood fuel prices in AESC 2018, we use an average of the state price data summarized below. Note that on an energy basis, wood pellet prices are close to those for distillate oil, but less than those for liquefied propane. Cord wood is about two-thirds of the pellets price on an energy basis.

[40] The wood pellet prices are basically consistent with those from other EIA sources. To illustrate, the wholesale pellet prices in the Eastern region (which includes the Midwest) averaged about $160/ton in 2017. See: https://www.eia.gov/biofuels/biomass/#table_data.

[41] For more information, see https://www.mass.gov/service-details/massachusetts-wood-pellet-prices.

[42] For more information, see http://www.maine.gov/energy/fuel_prices/.

[43] For more information, see https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm.

[44] For more information, see http://publicservice.vermont.gov/sites/dps/files/documents/Pubs_Plans_Reports/Fuel_Price_Report/2016/November%2016%20Fuel%20Price%20Report.pdf.

Table 19. AESC 2018 price forecast for residential wood pellets and cord wood[45]

		Wood Pellets (tons)	Cord Wood (cords)
New England price per unit	2017 $/unit	$264.5	$225.7
Heat Content[46]	MMBtu/unit	16.0	22.0
Price (2017 dollars)	2017 $/MMBtu	$16.53	$10.26
Price (2018 dollars)	2018 $/MMBtu	$16.86	$10.46

3.4. Avoided Costs

For the avoided costs for fuel oil products and other fuels by end-use, we used the prices as discussed above and the consumption as projected in AEO 2017. The consumption of these fuels is not expected to increase significantly over the study period. Moreover, the supply systems are flexible and diverse, and not subject to the capacity- or time-based constraints associated with electricity and natural gas. Thus, we believe that the market prices provide an appropriate representation of the avoided costs.

For petroleum-related fuels, we started with the costs of those fuels by sector by multiplying our projected regional prices for each fuel and sector by the relative quantities of each petroleum-related fuel that AEO projects will be used in that sector. We estimated that the crude oil price component of these projected prices is the portion that can be avoided through demand-side management (DSM) programs. For other fuels, we used the projected regional prices multiplied by the consumption of those fuels as projected by AEO with appropriate fractional adjustments based on the SEDS historical data. We considered the full cost of those fuels to be avoidable.

3.5. Fuel Emissions

Table 20 provides CO_2 emission rates for the various fuels. In this table, we have designated the rate for wood fuels as zero. This essentially a proxy value as there are many views about the GHG impacts of wood fuels.

[45] 2017 price in MMBtu is obtained by dividing the unit price by the heat content. The 2018 price represents a 2 percent inflation to the 2017 price.

[46] Wood pellet heat content is based on premium pellets with below 5 percent moisture content. Cord wood heat content is above the US EIA standard of 20 MMBtu/cord to represent greater hardwood use in New England. Actual values may vary considerably.

Table 20. CO_2 emission rates for non-electric fuels

Fuel	CO_2 Emission Rate (lbs/MMBtu)
Distillate fuel oil	161
B5 Biofuel	153
B20 Biofuel	129
Kerosene	159
LPG	139
RFO	173
Wood	zero
Wood & Waste	zero

Sources: Emission rates for petroleum products from EIA https://www.eia.gov/environment/emissions/co2_vol_mass.php.[47]

There are also SO_2 and NO_X emissions associated with fuel combustion.[48] Most of the available emission data is quite old and the impacts are very small. Thus, we see little value of further research at this time. However, for reference we provide the emission rates from the earlier study (see Table 21). Most of the Northeast has switched to Ultra-Low Sulfur Diesel (ULSD) fuel oil, which consists of only 50 or 15 parts per million (ppm) of sulfur.[49] By contrast, the historically used 1 percent sulfur oil contains 10,000 ppm. This shift to ULSD drastically reduces the SO_2 emissions by a factor of over 600. Distillate oil at 15 ppm sulfur is equivalent to 0.0016 lbs SO_2 per MMBtu, which rounds to the 0.002 lbs SO_2 per MMBtu shown in Table 21. Heavier oils likely will have higher sulfur content and the emission rates should be adjusted accordingly based on their actual characteristics.

In addition, there may be volatile organic compound (VOC) emissions from fuel oil handling and from wood fuel combustion, but that is not quantified as part of this study.

[47] Biofuel rates are based on the fossil fuel fraction. The direct CO_2 emission rate for wood combustion depends strongly on wood type and moisture content, but a rough range would be 200–250 lbs/MMBtu.

[48] This was addressed in sections 4.4.2 and 4.4.3 of AESC 2015.

[49] See https://www.eia.gov/todayinenergy/detail.php?id=5890 for more detail.

Table 21. SO_2 and NO_X emission factors

Emission Rates of Significant Pollutants from Fuel Oil Sector and Fuel	SO_2 (lbs/MMBtu)	NOx (lbs/MMBtu)
#2 Fuel Oil [a]		
Residential, #2 oil	0.002	0.129
Commercial, #2 oil	0.002	0.171
Industrial, #2 oil	0.002	0.171
Kerosene—Residential heating [b]	0.152	0.129
Wood—Residential heating [c]	0.020	0.341

Notes: For fuel oil, we assumed sulfur content of 15 ppm.
Sources: Table originally from AESC 2015, Exhibit 4-15. Page 4-93. Embedded sources include (a) Environmental Protection Agency, AP-42, Volume I, Fifth Edition, January 1995, Chapter 1, External Combustion Sources. http://www.epa.gov/ttnchie1/ap42/ (for SO_2 and NO_X); (b) AESC 2013; (c) James Houck and Brian Eagle, OMNI Environmental Services, Inc., Control Analysis and Document for Residential Wood Combustion in the MANE-VU Region, December 19, 2006. http://www.marama.org/publications_folder/ResWoodCombustion/RWC_FinalReport_121906.pdf.

4. COMMON ELECTRIC ASSUMPTIONS

A main goal of the AESC 2018 study is to estimate the electricity supply costs that would be avoided by reducing retail sales of electricity through energy efficiency initiatives or other emerging DSM programs. The avoided electricity supply costs include five different topic areas:

1. Avoided electricity market costs
2. Avoided electricity capacity costs
3. DRIPE
4. Avoided transmission and distribution
5. Avoided environmental costs not otherwise included in the above topic areas

This chapter addresses the modeling methodologies and parameters common to the first two topics. It includes methodologies, assumptions, and sources relating to the modeling frameworks, electricity demand, transmission, renewable policies, generic resource additions, known and anticipated resource additions, and known and anticipated resource retirements.

In addition to differences in underlying natural gas prices and fuel oil prices (discussed in previous chapters), modeling assumptions in AESC 2018 differ from those used in AESC 2015 in terms of:

- Lower projections for annual sales (even without taking energy efficiency into account)
- New assumptions on clean energy additions, including modeling of long-term contracting requirements that did not exist at the time of AESC 2015's writing (including Massachusetts' 83C and 83D legislation) and updates of other renewable policies including renewable portfolio standards (discussed in more detail in Chapter 0

- *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy* Policies)
- Different assumptions on known and estimated unit retirements
- Lower projections for compliance with the Regional Greenhouse Gas Initiative (RGGI)
- New assumptions on other environmental regulations, including the rollback of the federal Clean Power Plan and newly implemented state regulations such as Massachusetts Department of Environmental Protection's 310 CMR 7.74 and 7.75.

4.1. AESC 2018 Modeling Framework

The wholesale energy markets in New England are managed by ISO New England. There are two primary energy markets: (1) the Day-Ahead Market (where the majority of transactions occur) and (2) the Real-Time Market, in which ISO New England balances the remaining differences in energy supplies and demand.[50] On average, prices in these two markets are typically close to one another, although there is a tendency for greater volatility in the Real-Time Market. ISO New England also manages a capacity market, which is an auction-based system that ensures the New England power system has sufficient resources to meet future demand for electricity. Forward Capacity Auctions (FCAs) are held each year, three years in advance of a specified future operating period. ISO New England also manages a number of other ancillary markets, including regulation and reserve markets.

AESC 2018 uses three models to concurrently forecast avoided energy market and capacity costs. These models include:

The EnCompass model

Developed by Anchor Power Solutions, EnCompass is a single, fully integrated power system platform that allows for utility-scale generation planning and operations analysis. EnCompass is an optimization model that covers all facets of power system planning, including the following:

- Short-term scheduling, including detailed unit commitment and economic dispatch
- Mid-term energy budgeting analysis, including maintenance scheduling and risk analysis

[50] See ISO New England's 2016 Annual Markets Report for more information at https://www.iso-ne.com/static-assets/documents/2017/05/annual_markets_report_2016.pdf.

- Long-term integrated resource planning, including capital project optimization and environmental compliance
- Market price forecasting for energy, ancillary services, capacity, and environmental programs

EnCompass provides unit-specific, detailed forecasts of the composition, operations, and costs of the regional generation fleet given the assumptions described in this document. Synapse has populated the model with a custom New England dataset developed by Anchor Power Solutions and based on the 2015 Regional System Plan, which has been validated against actual unit-specific 2015 dispatch data.[51] Synapse integrated the New England dataset with the EnCompass National Database, created by Horizons Energy. Horizons Energy benchmarked its comprehensive dataset across the 21 NERC Assessment Areas and it incorporates market rules and transmission constructs across 76 distinct zonal pricing points. Synapse uses EnCompass to optimize the generation mix in New England and to estimate the costs of a changing energy system over time, absent any incremental energy efficiency or DSM measures.

More information on EnCompass and the Horizons dataset is available at www.anchor-power.com.

EnCompass modeling topology

EnCompass, like other production-cost and capacity-expansion models, represents load and generation by mapping regional projections for system demand and specific generating units to aggregated geographical regions. These load and generation areas are then linked by transmission areas to create an aggregated balancing area. Load and generation areas reported on in AESC 2018 can be found in Table 22; modeled load and generation areas are described in Table 23. In AESC 2015 and AESC 2013, the same topology was used for electricity-sector dispatch modeling, though both previous reports used a slightly different topology for reporting areas. In past years, modeling zones were matched to reporting zones using load-weighted averages or simple one-to-one translations (e.g., the New Hampshire reporting zone was assumed to be contiguous with the New Hampshire modeling zone). In the 2018 AESC study, we use load-weighted averages to translate all modeling zones into reporting zones.[52] While some zones under each topology are close matches, other reporting zones are made up of a number of different modeling zones. The percentages for weighting percentages are based on locations of pnodes in specific states and modeling zones (see Table 24).[53]

[51] ISO New England. "2015 Regional System Plan." Available at: https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[52] Recent modeling by Synapse indicates that while some adjacent load zones feature similar pricing in some years, prices are not similar enough to warrant a blanket assumption for zone assignments. In future years, this distinction in weighting will likely be even more different as state-specific prices diverge as a result of state-specific renewable and emission regulation policies, although this phenomenon has not yet been modeled.

[53] Historical pnode load factors for 2016 can be found at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/nodal-load-wgts.

Table 22. Reporting zones in AESC 2018

	AESC Reporting Zones
1	Maine
2	Vermont
3	New Hampshire
4	Connecticut
4a	SWCT (Southwest Connecticut, including Norwalk-Stamford)
4b	OTCT (Rest of Connecticut, i.e., Northeast CT)
5	Rhode Island
6	Massachusetts
6a	SEMA (Southeastern Massachusetts)
6b	WCMA (West-Central Massachusetts)
6c	NEMA (Northeastern Massachusetts)

Table 23. Modeled load zones in AESC 2018

EnCompass Region	ISO New England subarea / RSP
NE Maine Northeast	BHE
NE Maine West Central	ME
NE Maine Southeast	SME
NE New Hampshire	NH
NE Vermont	VT
NE Boston	Boston
NE Massachusetts Central	CMA/NEMA
NE Massachusetts West	WMA
NE Massachusetts Southeast	SEMA
NE Rhode Island	RI
NE Connecticut Northeast	CT
NE Connecticut Southwest	SWCT
NE Norwalk Stamford	NOR

Table 24. Translation between modeling zones (vertical) and reporting zones (horizontal)

		ME	NH	RI	VT	All CT	SW CT	OT CT	All MA	SE MA	NE MA	WC MA
NE Maine Northeast	BHE	14%	-	-	-	-	-	-	-	-	-	-
NE Maine West Central	ME	52%	-	-	-	-	-	-	-	-	-	-
NE Maine Southeast	SME	34%	-	-	-	-	-	-	-	-	-	-
NE New Hampshire	NH	-	81%	-	3%	-	-	-	-	-	-	-
NE Vermont	VT	-	16%	-	90%	-	-	-	-	-	-	-
NE Boston	Boston	-	-	-	-	-	-	-	38%	-	100%	1%
NE Mass. Central	CMA/ NEMA	-	3%	-	-	-	-	-	17%	-	-	54%
NE Mass. West	WMA	-	-	-	7%	1%	-	3%	14%	-	-	45%
NE Mass. Southeast	SEMA	-	-	3%	-	-	-	-	24%	78%	-	-
NE Rhode Island	RI	-	-	97%	-	-	-	-	7%	22%	-	-
NE Connecticut Northeast	CT	-	-	-	-	46%	-	97%	-	-	-	-
NE Connecticut Southwest	SWCT	-	-	-	-	34%	64%	-	-	-	-	-
NE Norwalk Stamford	NOR	-	-	-	-	19%	36%	-	-	-	-	-

Neighboring regions modeled in this study are New York, Quebec, and the Maritime Provinces. These regions are not represented with unit-specific resolution. Instead, they are represented as a source or sink of import-export flows across existing interfaces in order to reduce modeling run time.[54]

[54] In this analysis, the Maritimes zone includes Emera Maine and Eastern Maine Electric Cooperative (EMEC) which are not part of ISO New England and, therefore, are not included in any of the New England pricing zones used in this study. These regions are not modeled as part of the Maine pricing zone and were modeled as part of the New Brunswick transmission area.

The Renewable Energy Market Outlook model

In addition to EnCompass, AESC 2018 uses Sustainable Energy Advantage's New England Renewable Energy Market Outlook (REMO), a set of models developed by Sustainable Energy Advantage that estimate forecasts of scenario-specific renewable energy build-outs, as well as REC and clean energy certificate (CEC) price forecasts. Within REMO, Sustainable Energy Advantage can define forecasts for both near-term and long-term project buildout and REC pricing.

Near-term renewable builds are defined as projects under development that are in the advanced stages of permitting and have either identified long-term power purchasers or an alternative path to securing financing. These projects are subject to customized, probabilistic adjustments to account for deployment timing and likelihood of achieving commercial operation. The near-term REC price forecasts are a function of existing, RPS-certified renewable energy supplies, near-term renewable builds, regional RPS demand, alternative compliance payment (ACP) levels in each market, and other dynamic factors. Such factors include banking, borrowing, imports, and discretional curtailment of renewable energy.

The long-term REC price forecasts are based on a supply curve analysis taking into account technical potential, resource cost, and market value of production over the study period. These factors are used to identify the marginal, REC price-setting resource for each year in which new renewable energy builds are called upon. The long-term REC price forecast is estimated to be the marginal cost of entry for each year, meaning the premium requirement for the most expensive renewable generation unit deployed for a given year.

The FCM model

The 2018 AESC study uses a spreadsheet model to develop FCM auction prices for power years from June 2018 onwards. The major input assumptions regarding the forecasts of peak load and available capacity in each power year are coordinated with the input assumptions used in the Encompass energy market simulation model. General assumptions for this model include the assumption that resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 9 through FCA 11, the assumption that FCM prices will be to a large degree determined by the price of new peaking units, and the assumption that the supply curve in future FCAs feature similar slopes to those observed in FCA 9 through FCA 11. Please see Chapter 5. *Avoided Capacity Costs* for more detail on this methodology.

Modeled market rules

The EnCompass model approximates the market rules that are used in ISO New England. The following sections provide an overview of the model's approach to these rules.

Marginal-cost bidding

In deregulated markets, generation units are assumed to bid marginal cost (opportunity cost of fuel plus variable operating and maintenance costs plus opportunity cost of tradable permits). The model prices are based on such representative marginal costs. Notably, the model calculates bid adders to close any gap between energy market revenues and submitted bids. The resulting energy-price outputs are benchmarked against historical and future prices.

Installed capacity

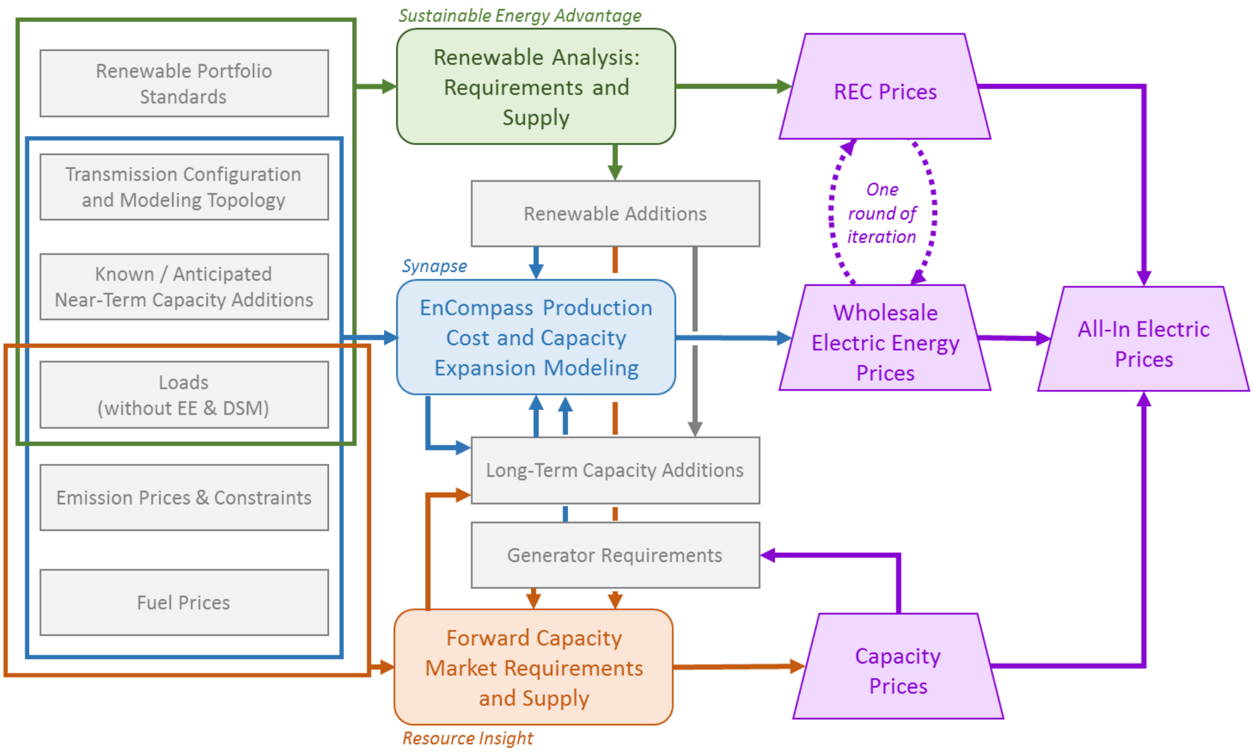
Installed-capacity requirements for the EnCompass model include reserve requirements established by ISO New England on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec installed-capacity credits) are described in Chapter 5 *Avoided Capacity Costs*. Installed capacity for the energy model in each model year is consistent with the values assumed in the FCA analysis, although the values are not necessarily the same due to imports and exports.

Ancillary services

EnCompass allows users to define generating units based on each unit's ability to participate in various ancillary services markets including Regulation, Spinning Reserves, and Non-Spinning Reserves. The model allows users to specify these abilities for each unit, at varying levels of granularity. EnCompass allows units to contribute to contingency and reserves requirements, and it considers applicable costs when determining bids.

The interactions between the models used in this study are highlighted in Figure 14.

Figure 14. AESC 2018 modeling schematic



Modeling timescale

In EnCompass, REMO, and the FCM Model, we explicitly model 18 years from 2018 through 2035. In order to develop 15-year and 30-year levelized avoided costs, AESC 2018 continues the trajectory of each avoided cost component through 2050.[55]

For each modeled year, we use the temporal resolutions described below.

For avoided energy costs:

- Each year is first modeled in EnCompass' capacity-expansion construct. In this construct, EnCompass optimizes to determine the most cost-effective capacity additions.[56] Under this construct, EnCompass is run at the resolution of a typical week—this means that EnCompass represents each year from 2018 to 2035 as an aggregation of 12 months, each of which is represented by a typical week, each week of which is represented by five "on peak" days and two "off peak

[55] In most cases, this involves applying a cumulative average growth rate (based on 2030 and 2035) to each year from 2036 to 2050.

[56] Note that these capacity additions are limited to generic resource types (described below). Note that we enter other capacity as exogenous additions.

days," each day of which is represented by a 24-hour chronological dispatch period.

- After running EnCompass in the capacity-expansion construct, we next run it in production-cost mode for a subset of years. EnCompass' production-cost mode uses the capacity-expansion outputs as "seed" data, and it allows the model to better approximate unit commitment over the course of a year. In this construct, we use an 8760-hour resolution for each year between 2018 and 2035.

- Hourly 8760 data are then aggregated using load-weighted averages to the four time periods used for reporting in previous AESC studies (summer on-peak, summer off-peak, winter on-peak, and winter off-peak).[57]

For avoided capacity costs:

- Program administrators can claim avoided capacity by either bidding capacity (cleared) into the FCAs, or by reducing peak summer loads through non-bid capacity (uncleared) (which then becomes phased-in load forecasts for subsequent FCAs). Hence, all avoided capacity will be stated per kW of peak load reduction.

- The capacity value of passive demand resource (such as an energy efficiency program) or an active demand resource cleared in the capacity market will be determined by the capacity value accepted by the ISO. The user of the model will need to estimate how much capacity value will be recognized by the ISO for each resource that will be bid into the market. The capacity value of energy efficiency that is not cleared in the capacity market will be approximately the load reduction of the measure at the ISO's normal peak conditions.[58]

- ISO New England models peak load by regressing daily peak in each day of July and August on a number of variables, including monthly energy, $WTHI^2$, a time trend × WTHI, and dummies for weekends and holidays (also × WTHI). While it is difficult to determine exactly how load reductions in various summer conditions will affect the peak forecast, an energy efficiency measure that reduces load throughout the summer or in the days with above-average WTHI should fully

[57] These time periods are defined as follows: Winter on-peak is October through May, weekdays from 7am to 11pm; winter off-peak is October through May, weekdays from 11pm to 7am, plus weekends and holidays; summer on-peak is June through September, weekdays from 7am to 11pm; and summer off-peak is June through September, weekdays from 11pm to 7am, plus weekends and holidays.

[58] The normal peak conditions are defined as a weighted temperature-humidity index (WTHI) for the day of 79.9°, where the weighting is (10 × the current day's THI, plus 5 × the previous day's THI, plus 2 × the THI two days earlier) ÷ 17. The daily THI is 0.5 × temperature +0.3 × dewpoint +15. The THIs are computed for eight cities (Boston, Hartford, Providence, Portland, Manchester NH, Burlington VT, Springfield, and Worcester) and weighted by zonal loads.

affect the load forecast. Load management that affects only a few summer days would have a much smaller impact on the load forecast.

For DRIPE:

- Energy DRIPE is estimated as proportional to avoided energy cost. Thus, energy DRIPE can be applied to any level of disaggregated avoided energy cost.
- Capacity DRIPE is stated per kW of peak load reduction, for bid resources and for non-bid load reductions. Those values can be attributed to programs in the same manner as the avoided capacity costs.
- Natural gas supply DRIPE and oil DRIPE are intrinsically annual values.
- Natural gas basis DRIPE is associated with high-load days in the winter, for both electric and natural gas loads.

For avoided transmission and distribution:

- Avoided T&D costs result from load reductions in the hours in which T&D equipment experiences high loads. These hours are spread across the peak hours in summer and winter (depending on the utility's mix of loads) and sometimes into shoulder months and off-peak hours.
- Pool transmission resources are planned for system extreme conditions, which would be hotter-than-normal (one day in ten years) summer days. These costs are allocated to the summer peak in the standard avoided-cost tables, and they will be avoidable by any resource that reduces the ISO forecast for extreme loads.

4.2. Emerging DSM Programs

The AESC 2018 avoided cost streams include 8,760 values in addition to the four traditional energy costing periods (summer on-peak, summer off-peak, winter on-peak, and winter off-peak). The 8,760 avoided cost values should provide individual program administrators flexibility in designing emerging DSM programs beyond traditional DSM programs that have relied upon the avoided cost value streams provided in previous AESC reports (see Table 25). In addition, the 8,760 avoided cost values may also help refine the quantification of traditional DSM programs that have relied upon avoided cost values from previous AESC studies.

On the issue of emerging DSM technologies, the Analysis Team believes that there is currently no need to incorporate additional inputs into the model that may impact the development of avoided costs for emerging DSM technologies. The following table summarizes the application of AESC 2018 components for several emerging technologies facing program administrators.

Table 25. Current status of emerging DSM technologies

Technology	Other Components or Considerations
Conservation Voltage Reduction	The traditional avoided costs streams may be applied for CVR programs. CVR occurs in front of customer meter. Some feeders, such as those with high motor load, may not be appropriate for CVR. CVR factors for feeders would need to be quantified. Utilities must maintain service quality requirements, which may limit applicability. Distribution planning personnel from program administrators should weigh in on the matter.
Volt-Var Control	The traditional avoided costs streams may be applied for VVO programs. VVO occurs in front of customer meter. Hourly data for real and reactive power will determine hourly line losses, and the difference between baseline and impact losses yields energy savings. Distribution planning personnel from program administrators should weigh in on the matter.
Behind-the-Meter Storage	User would need to determine charging and discharging periods. If one predicts the peak hour in each year of the study that sets the FCM clearing price, then one can discharge the battery at that peak (100 percent coincident with peak). While batteries reduce energy in one period, batteries increase usage in other periods. Batteries consume more energy overall due to round-trip losses. Ideally, avoided energy costs are higher than the increased energy costs. Because of this and the cycling nature, 8760 may be useful. Storage programs may apply the negative of the avoided cost values when charging consistent with current practices used by program administrators.
Behind-the-Meter Distributed Generation	Depending on the resource type and if the resource has islanding capability, there may be some benefit for reliability for the islanded customer.
Peak Load Management	The timing of when demand response occurs is important, because it's primary goal is to typically to reduce energy use in higher priced periods. Current program designs have been focused on reducing customer load over a small number of hours during the summer season, however Study Group members have identified a preference for energy modeling that broadly captures the value from varying program designs in both summer and winter seasons. The 8760 avoided cost results should provide program administrators with additional granularity. Other peak load management programs that are 100 percent coincident may function like BTM storage discharge. Some Study Group members have expressed an expectation that there would be some consideration of whether resources that are actively dispatched in the ISO New England economic dispatch have different cost implications than passive utility-dispatched programs.
Non-Wires Alternatives	NWA projects are usually driven by T&D constraints, and primarily distribution constraints. Each Massachusetts program administrator has a different method for determining avoided T&D, and much of the information that goes into those calculations may be confidential. There may also be a combination of different technologies that are unique to the utility's service territory and situation.

Technology	Other Components or Considerations
Strategic Electrification	For a small number of heat pumps and EVs, traditional avoided costs may be applicable. This is the same methodology currently employed by several program administrators. Strategic electrification programs could leverage the traditional avoided costs by applying the negative values when there is incremental load. A large electrification program (for EVs and/or heat pumps) would require different load forecast assumptions such as those modeled in the High Load sensitivity described in Chapter 12. The Analysis Team requested input from the Study Group to determine the appropriate level of EV and heat pump adoption for high penetration scenarios. For example, recent Bloomberg New Energy research reports suggest that EV adoption could reach 4 percent of annual new automotive sales by 2021 and 10 percent by 2025. New England new automotive sales were 807,000 in 2016; 10 percent of annual new automotive sales would be approximately 80,000 EVs or almost 4.5 times the 18,000 EVs currently registered in New England.[59] Other strategic electrification programs may be similar to existing energy efficiency programs. The AESC 2018 sensitivity chapter outlines a scenario with greater adoption of EVs and heat pumps. A ratepayer-funded EV program for charging stations may have similar qualities and considerations as Behind-the-Meter Storage or Peak Load Management depending on the nature of the program.

4.3. New England System Demand

Forecasts of annual peak demand and energy used in each of the AESC 2018 models were based on the 50/50 values published by ISO New England in the 2017 Forecast Report of Capacity, Energy, Loads and Transmission (CELT) study.[60]

Annual energy and peak load forecasts

In AESC 2018, we rely on the forecast values determined by ISO New England for forecasts of annual energy and peak load for 2018 through 2026. Because the main modeling case in the 2018 AESC study assumes that no new energy efficiency or other DSM measures are installed in 2018 and later years, we increase ISO New England's econometric forecasts to reflect the amount of passive demand resource (PDR) that is planned for installation in 2017.[61,62] Beyond 2026, we extrapolate annual energy and peak

[59] More information on automotive data for New England can be found at autoalliance.org.

[60] The "50/50" forecast contains ISO New England's statistically most-likely estimate of future demand. ISO New England also publishes other forecasts for demand, including a 90/10 and a 10/90 forecast, which represent the high and low range of estimates for demand.

[61] Note that the CELT forecast does not include any explicit assumptions regarding the adoption of electric vehicles or other ongoing strategic electrification.

[62] This adjustment for PDR is based on the cumulative PDR estimated to be in place in 2017, according to CELT 2017. Note that unlike the AESC 2015 study, we do not decrease demand in future years to reflect PDR for which program administrators are financially committed, but have not yet not delivered (i.e., resources with capacity supply obligations in the 8th Forward Capacity Auction and later years, See AESC 2015, pages 5-14). Although these resources do have a financial commitment to be implemented, we believe that embedding them in the load forecast would prohibit users of the AESC 2018 from evaluating these resources' cost-effectiveness because of double-counting.

load using the cumulative average annual growth rate (CAGR) of the last five years (2022–2026) (see Figure 15 and Figure 16). In 2016, PDR and PV solar reduced gross system energy demand by 11 percent and summer peak demand by 10 percent; by 2026, ISO New England estimates that these values will grow to 22 percent and 17 percent, respectively.

Figure 15. Historical and projected annual energy forecasts for all of ISO New England

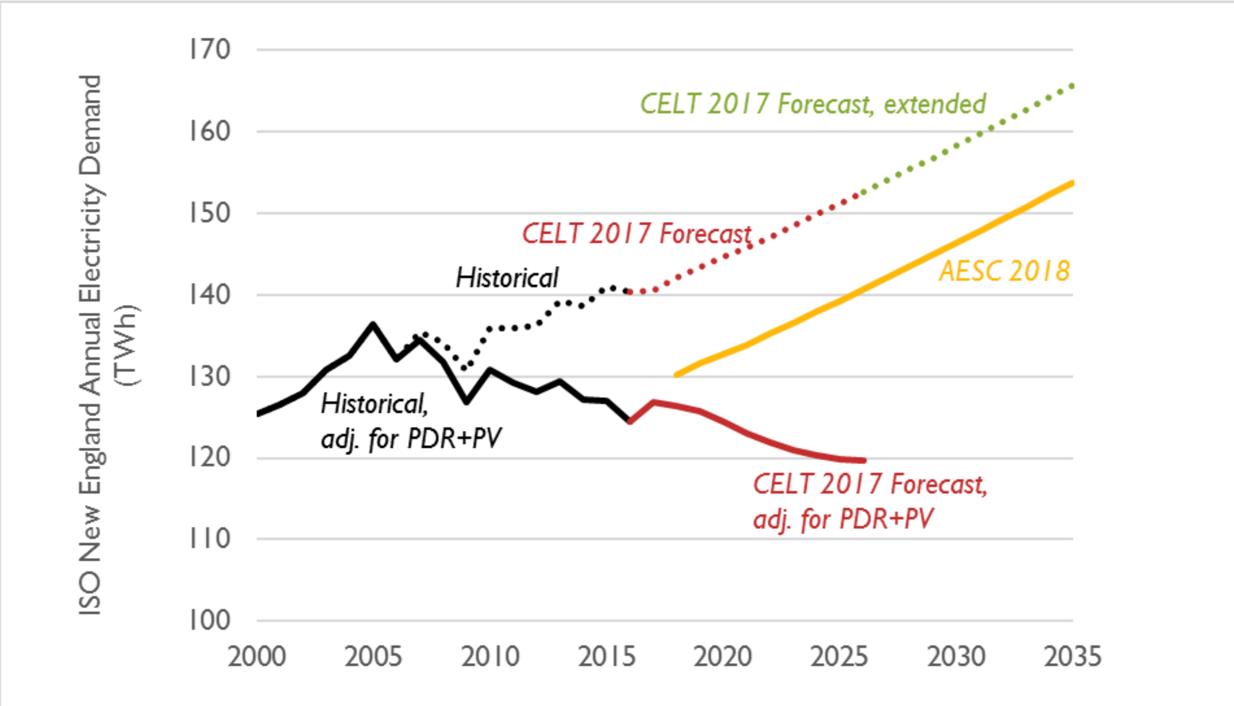
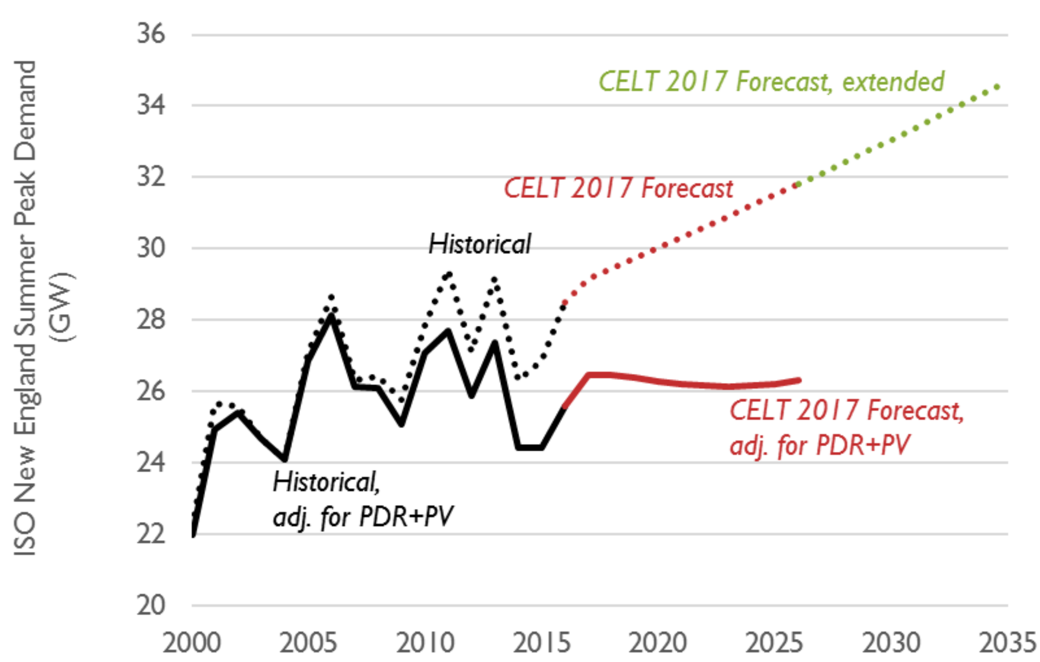


Figure 16. Historical and projected summer peak demand forecasts for all of ISO New England



Note: A trajectory is not shown for AESC 2018 in this chart; peak demand (and all hourly demand) is estimated using a combination of the annual demand in Figure 15 and hourly load shapes published by ISO in CELT 2017.

In May 2017, ISO New England released its newest electricity demand forecast, CELT 2017.[63] As in the CELT forecasts before it, in CELT 2017 ISO New England developed a forecast of annual energy for New England as a whole and for each individual state and load zone. These forecasts are based on regression models that integrate inputs on previous annual consumption, real electricity price, real personal income, gross state product, and heating and cooling degree days for data from 1990 through 2016.

In the past, ISO New England developed the load forecasting model and its coefficients by analyzing the historical relationships between energy requirements and those independent variables since 1984. In those years, the forecast implicitly contained some level of reductions from efficiency programs due to the programs in effect during the historical period.

Since 2008, ISO New England has sought to compensate for these "embedded energy efficiency" effects by explicitly accounting for PDR. Thus, programmatic energy efficiency is excluded from the main ISO New England econometric forecasts, producing a "gross" forecast for annual energy and peak demand

[63] Further information about the CELT forecast can be found at ISO New England's web page, https://www.iso-ne.com/system-planning/system-plans-studies/celt and https://www.iso-ne.com/static-assets/documents/2017/05/modeling_procedure_2017.pdf.

that is higher than it would be without the impact of PDR.[64] Since 2008, ISO New England has put forth a separate PDR forecast for energy efficiency resources, and since 2015, it has published a third forecast for distributed solar (DG PV). ISO New England then subtracts the forecasted quantities of PDR and DG PV from its gross forecast to estimate a “net” forecast, a lower number that reflects the actual estimated demand for each modeled year.

Load forecasts and capacity requirements

The CELT load forecast in one year is used in the forward capacity auction early in the next year, to set the installed-capacity requirement for the capacity period starting about three years after that. For example, the peak forecast for the summer of 2021 (released in April 2017) was used to set the installed-capacity requirement for FCA 12 (held in February 2018), which set the capacity obligations and prices for June 2021 to May 2022.

The actual capacity requirement is determined by the intersection of the supply curve (determined by resource bids) and a sloped “demand curve” set by ISO New England. Figure 17 shows the ISO demand curve used in FCA 10, and Figure 18 shows the more complex demand curve design for FCA 11.[65]

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[64] However, the econometric forecast can be impacted by the effects of federal energy efficiency standards and other non-programmatic energy efficiency.

[65] The ISO also sets demand curves for portions of New England in which capacity prices might separate from the overall ISO price. Construction of transmission and redistribution of generation resulted in all zones clearing at the same price in FCA 10 and 11.

Figure 17: Sloped demand curve, FCA 10

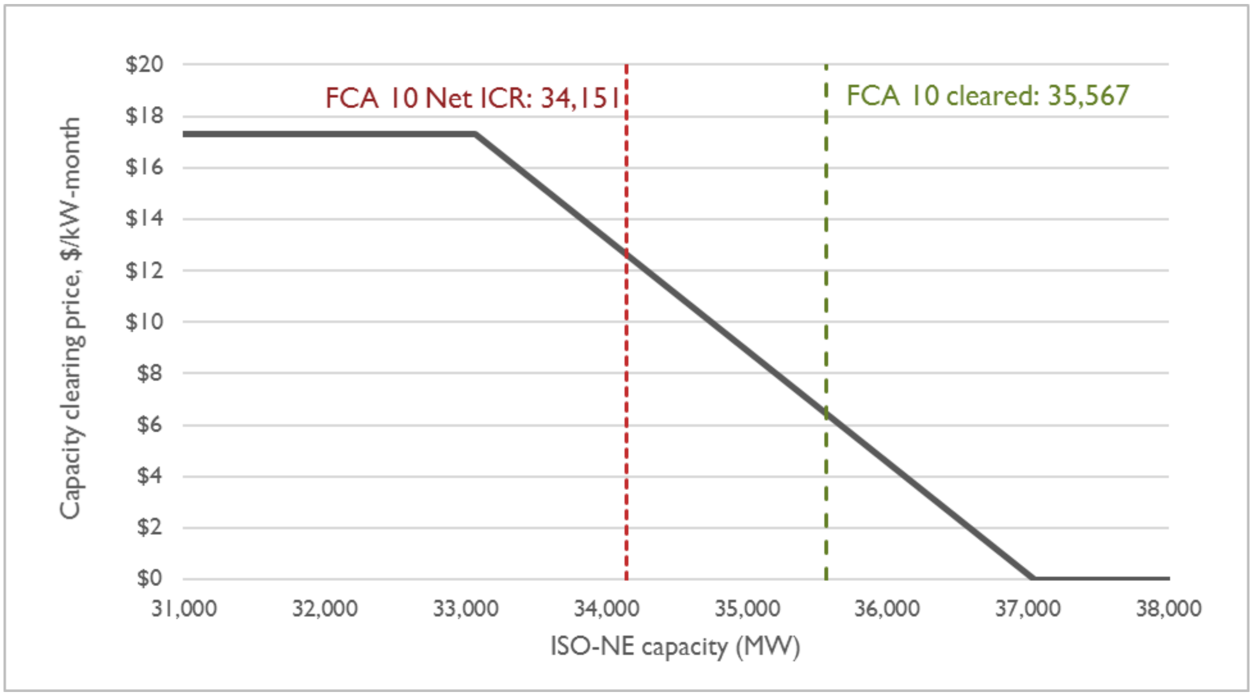
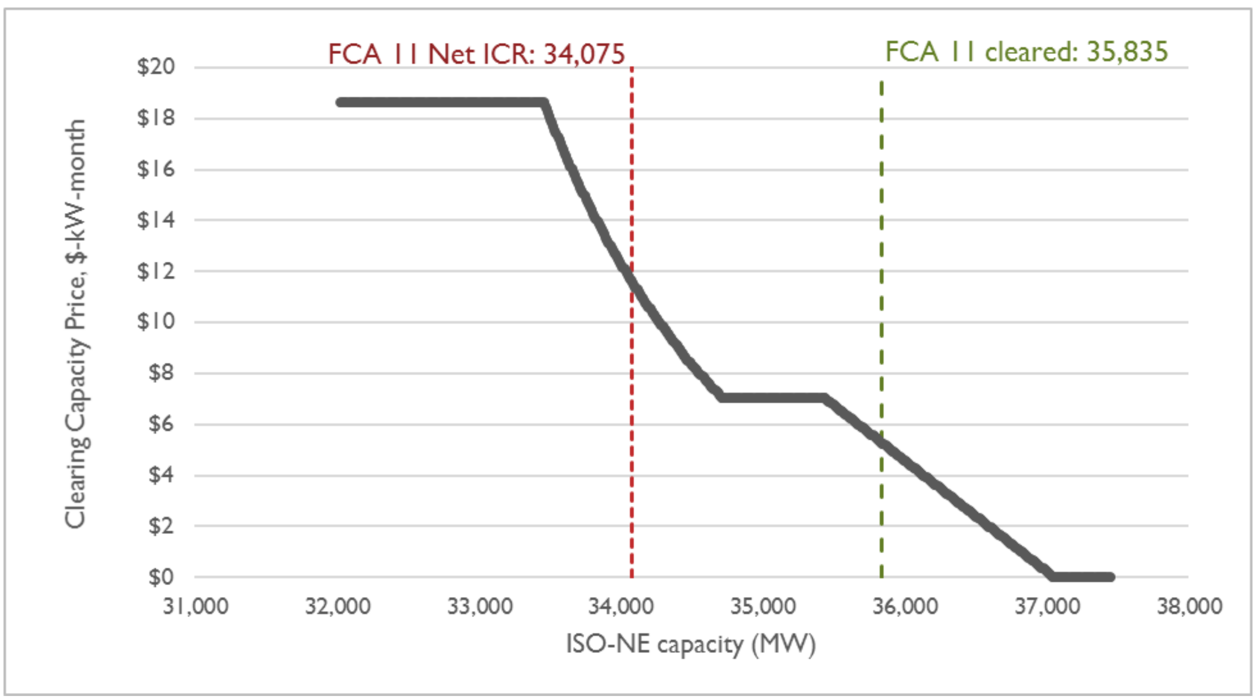


Figure 18: Sloped demand curve, FCA 11



Load shapes

After estimating annual energy and peak demand, AESC 2018 applies an hourly load shape developed for each load zone published by ISO New England in the 2017 CELT study.[66] Note that while it is possible that load shapes may change over time, the scale and shape of these changes are uncertain. As a result, we rely on ISO New England's load shapes for purposes of simplification.[67]

Energy losses

As an input, the EnCompass model requires energy forecasts that include any transmission or distribution losses. According to EIA, the average amount of electricity lost to transmission and distribution nationwide was 5.2 percent between 2010 and 2015.[68] In other words, for every 1.00 MWh delivered to end-use customers, 1.05 MWh of electricity needed to be generated. ISO New England's CELT forecast for system demand refers to the total electricity required to supply the system (in our example, it would forecast an energy requirement of 1.05 MWh, rather than 1.00 MWh). As a result, we are not planning to account for any transmission or distribution losses in the electricity energy modeling.[69] Please see Chapter 5 *Avoided Capacity Costs* for a discussion of how losses are modeled in terms of avoided capacity.

Incorporating energy efficiency and DSM measures in the ISO's forecast

After developing econometric forecasts for annual energy and peak load, ISO New England produces two additional forecasts: one for PDR, and one for distributed solar. ISO New England estimated energy efficiency and distributed generation effects first based on levels of capacity that has cleared in the FCM, and secondly on future estimated levels of resource addition and attrition.

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[66] Hourly load shapes developed by ISO New England for the CELT 2017 forecast can be found at https://www.iso-ne.com/static-assets/documents/2017/05/rsp17_sa_eei.txt

[67] Note that in our modeling, we assume hourly capacity factor shapes for utility-scale and distributed solar consistent with those reported by NREL in its PVWatts tool (available at http://pvwatts.nrel.gov/). Hourly capacity factor shapes for onshore wind are based on reported capacity factors by ISO New England for 2015 and 2016 (see https://www.iso-ne.com/static-assets/documents/2015/04/hourly_wind_gen_2015.xlsx and https://www.iso-ne.com/static-assets/documents/2016/04/hourly_wind_gen_2016.xlsx). Hourly capacity factor shapes for offshore wind are based on data estimated by Synapse in 2016 using the Weather Research and Forecasting (WRF) model. This methodology is in line with the analysis of offshore wind energy resources by Dvorak M J, Corcoran B A, Ten Hoeve J E, McIntyre N G and Jacobson M Z. 2013. "US East Coast offshore wind energy resources and their relationship to peak-time electricity demand." *Wind Energy*. 16: 445-53. Available at: http://onlinelibrary.wiley.com/doi/10.1002/we.1524/abstract;jsessionid=F1116B50C23EB8B4389596CAD240CAD1.f02t01.

[68] See https://www.eia.gov/electricity/state/unitedstates/xls/us.xlsx for more information.

[69] Note that models used in previous AESC studies differed on the required input; in AESC 2013, for example, the model used required an input of end-use electricity demand, requiring the modelers to adjust the modeled forecast by an estimate of transmission and distribution losses.

During the development of each CELT forecast, ISO New England works with the Energy Efficiency Forecast Working Group (EEFWG), which produces an estimate for future energy efficiency based on expected future energy efficiency expenditures and program performance. While these projections are useful for forecasting future energy efficiency savings, they are not relevant to the 2018 AESC forecast, which is based on loads without future incremental energy efficiency savings.

Incremental electrification

In its 2017 CELT forecast, ISO New England does not make any explicit assumptions regarding increases in system demand that result from vehicle electrification or other types of strategic electrification.[70] In the 2018 AESC Study, we likewise assume no increase in annual energy sales or system peak resulting from increased electrification. Note that other levels of load (which could incorporate impacts from electrification) could be modeled in a sensitivity.

4.4. Anticipated Non-Renewable Resource Additions and Retirements

The following section highlights key input assumptions regarding retirements of existing units as well as anticipated additions of new generating units. Note that this section is not meant to be a comprehensive census of all existing generators; instead, it is meant to provide an overview of the significant changes to non-renewable capacity that is expected to occur during the analysis period.[71] For information on renewable resource additions, see Chapter 0.

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[70] Note that the electricity demand forecast assumed in AEO 2017 (not used in the 2018 AESC analysis) assumes very low levels of future vehicle electrification. The electrification levels modeled in AEO 2017 are a small fraction of the electric vehicle targets agreed to by Connecticut, Massachusetts, Rhode Island, Vermont, and four other states (see "ZEV MOU" at http://www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf/ for more information).

[71] Note that we are not proposing to include any incremental demand response resources in our analysis, in line with our assumptions for conventional energy efficiency resources.

Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies.

Nuclear units

There are three remaining nuclear plants in New England: Pilgrim (MA), Seabrook (NH), and Millstone (CT). Pilgrim and Seabrook each have one unit, Millstone has two (see Table 26). Of the four units, only Pilgrim has announced a retirement date within the analysis period. The Nuclear Regulatory Commission (NRC) has relicensed Pilgrim 1, Millstone 2, and Millstone 3, along with many other reactors outside New England, without denying a single extension.[72] Based on this track record and the lack of evidence suggesting that the NRC would deny license renewals for any of these plants, we assume that Seabrook 1 and Millstone 3 continue to operate throughout the entire modeling period. We assume that Millstone 2 retires in July 2035. We do not model any incremental nuclear unit additions during the study period.

Table 26. Nuclear unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	License Expiration Date
Pilgrim 1	MA	670.0	June 2019	June 2032
Seabrook 1	NH	1,242.0	None	March 2030
Millstone 2	CT	909.9	None	July 2035
Millstone 3	CT	1,253.0	None	November 2045

Coal units

As of October 2017, there are six coal units operating in New England, spread across three power plants (see Table 27). Other recently retired plants include Brayton Point (retired June 2017), Mount Tom (retired June 2014), and Salem Harbor (retired June 2014).

Of the remaining units, Bridgeport Station 3 has already announced a retirement date. The Merrimack and Schiller units have undergone substantial environmental retrofits in recent years. Merrimack and Schiller are both owned by Eversource (d/b/a Public Service Company of New Hampshire), and are obligated to be sold as part of a settlement requiring Eversource to comply with New Hampshire's electricity restricting legislation.[73] In October 2017, PSNH announced the sale of these coal plants to Granite Shore Power, LLC for $175 million.[74] As part of this sale, the new owners must keep these plants

[72] Detail on nuclear license expiration dates can be found at https://www.nei.org/Knowledge-Center/Nuclear-Statistics/US-Nuclear-Power-Plants/US-Nuclear-Plant-License-Information.

[73] See http://www.puc.state.nh.us/regulatory/docketbk/2016/16-817.html for more information.

[74] More information on the October 2017 sale of Schiller, Merrimack, and Eversource's other power plants can be found at https://www.eversource.com/content/ct-c/about/news-room/new-hampshire/newspost?Group=new-hampshire&Post=eversource-announces-sale-of-power-plants

in operation for 18 months (i.e., through at least Summer 2019). In this analysis, we make the following assumptions for these units' future operation:

Schiller

The Schiller power plant consists of four 50 MW units. Schiller 4 and 6 primarily burn coal to supply electricity, while Schiller 5 is primarily powered by biomass. Schiller is also the site of a 21 MW gas-fired combustion turbine. Schiller 4, Schiller 5, and Schiller 6 were all constructed prior to 1957, making all three units at least 60 years old. Schiller 4 and Schiller 6 possess selective non-catalytic reduction (SNCR) and low NO_X burners to control for NO_X emissions, electrostatic precipitators to control for particulate matter, and halogenated sorbent injection systems to control for mercury.[75] Schiller 5 uses fluidized bed limestone injection to reduce SO_2 emissions, an SNCR to control for NO_X, and a baghouse to control for particulate matter. All four Schiller units have capacity commitments through FCA-11 (i.e., through May 31, 2021). Schiller 4 and 6 operated at capacity factors of about 8 percent in 2016 and 4 percent in the first eight months of 2017 (see Figure 19). The biomass-fueled Schiller 5 operated at about 68 percent capacity factor throughout this period. Coal plants have high fixed operation and maintenance costs, and they are rarely cost-effective to keep operating at such low capacity factors. We assume that Schiller 4 and Schiller 6 retire on June 1, 2021, and that the other two Schiller units are operational throughout the analysis period.[76]

Merrimack

The Merrimack power plant consists of two coal-fired units, and two 19 MW gas-fired combustion turbines. In aggregate, the coal capacity at Merrimack is about three times the size of the coal/biomass capacity at Schiller. Both coal units at Merrimack were built in the 1960s, making the two units about 50 years old. Both Merrimack coal units feature a wet fluidized gas desulphurization system to control for SO_2, a selective catalytic reduction (SCR) system to control for NO_X, and an electrostatic precipitator to control for particulate matter. All four Merrimack units have capacity commitments through FCA-11 (i.e., through May 31, 2021). Merrimack 1 operated at a capacity factor of 13 percent in 2016 and 7 percent in the first eight months of 2017; Merrimack 2 operated at 8 percent and 5 percent in those periods (see Figure 19). We assume that Merrimack 1 and Merrimack 2 retire on January 1, 2025, and that the other two Merrimack units are operational throughout the analysis period.[77]

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[75] Additional data on environmental controls is available at ampd.epa.gov.

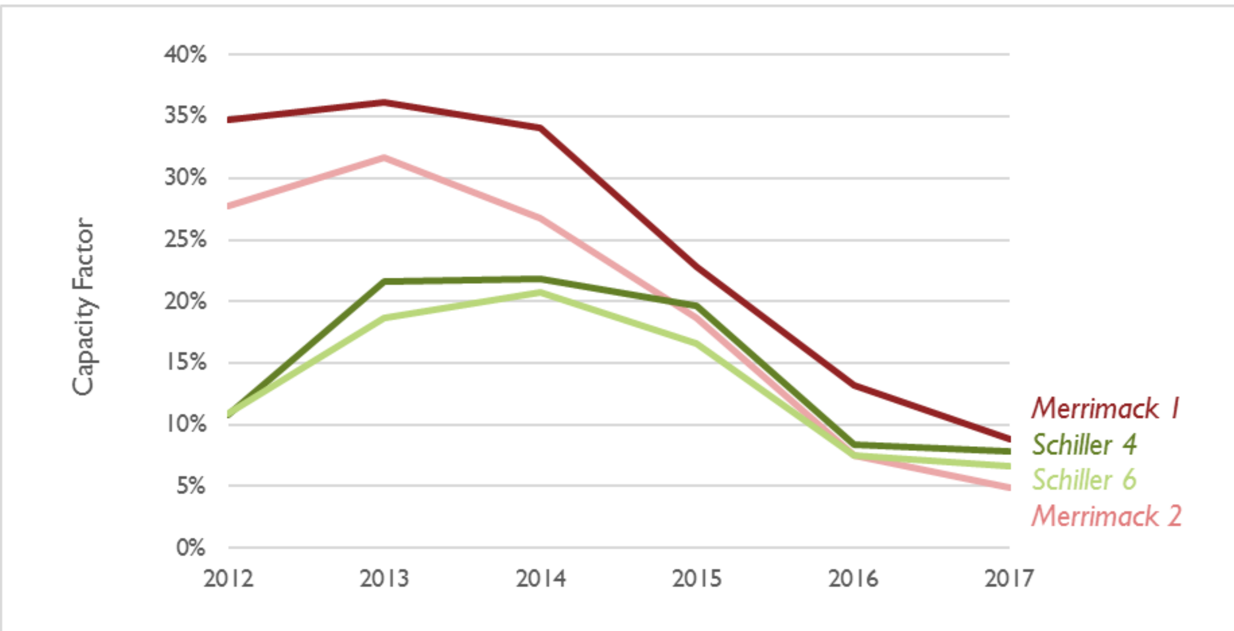
[76] In AESC 2013, Schiller 4 and Schiller 6 were assumed to retire in 2020. In AESC 2015, these units were not assumed to retire. Schiller 4 and Schiller 6 are assumed to retire once their currently existing capacity supply obligation retires at the end of May 2021.

[77] In both AESC 2013 and AESC 2015, all four Merrimack units were assumed to operate throughout those studies' analysis periods. Our assumption that Merrimack 1 and Merrimack 2 retire in 2025 is based on these two units' marginally-better operating economics (relative to Schiller 4 and Schiller 6).

Table 27. Coal unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	Modeled Retirement Date	Notes
Bridgeport Station 3	CT	400.0	June 2021	June 2021	-
Merrimack 1	NH	113.6	None	January 2025	-
Merrimack 2	NH	345.6	None	January 2025	-
Schiller 4	NH	50.0	None	June 2021	-
Schiller 5	NH	50.0	None	None	Primarily biomass-fired
Schiller 6	NH	50.0	None	June 2021	-

Figure 19. Capacity factors for coal-burning Merrimack 1, Merrimack 2, Schiller 4, and Schiller 6



We do not model any incremental coal unit additions during the study period.

Natural gas and oil units

Throughout the study period, we assumed over 3,300 MW of new capacity additions from natural gas resources. Table 28 lists the units that were exogenously added throughout the study period. Data on capacities and online dates are from Forward Capacity Market obligations and supplemented by data from EIA's Form 860. We assumed these resources would be primarily natural gas-fired, although some also possess dual-fuel capability.

Table 28. Incremental natural gas / oil additions

Unit	State	Capacity (MW)	Modeled Online Date	Unit Type
Bridgeport Harbor 6	CT	484.3	June 2019	Combined Cycle
Burrillville Energy Center 3	RI	485.0	June 2019	Combined Cycle
CPV Towantic Energy Center CTG1	CT	285.0	May 2018	Combined Cycle
CPV Towantic Energy Center CTG2	CT	285.0	May 2018	Combined Cycle
CPV Towantic Energy Center STG	CT	280.5	May 2018	Combined Cycle
Salem Harbor 5	MA	158.4	January 2018	Combined Cycle
Salem Harbor 6	MA	158.4	January 2018	Combined Cycle
Salem Harbor 7	MA	240.7	January 2018	Combined Cycle
Salem Harbor 8	MA	240.7	January 2018	Combined Cycle
Canal 3	MA	333.0	June 2019	Combustion Turbine
Medical Area Total Energy Plant CT3	MA	13.8	May 2017	Combustion Turbine
Medway Peaker 1	MA	194.8	June 2018	Combustion Turbine
Wallingford CTG6	CT	50.0	June 2018	Combustion Turbine
Wallingford CTG7	CT	50.0	June 2018	Combustion Turbine
MIT Central Utilities/Cogen Plant (new)	MA	44.0	Apr 2020	Combustion Turbine

Note: The Killingly Energy Center (a 550 MW NGCC) is not included on this list as it has not cleared the capacity market and is not under construction. Similarly, only the first half of the proposed Burrillville Energy Center is included here. Footprint Power has an FCM obligation as of June 2017; however, this power plant is not yet operational. For the purposes of this modeling, we assumed this plant is online as of January 1, 2018.

In addition, several natural gas- and oil-fired units were assumed to retire over the study period. Table 29 details these units, along with other units of this resource type that have recently retired. Unit retirements are based on announcements by the unit owners. We do not assume any additional exogenous natural gas- or oil-fired unit retirements beyond those detailed in this table.

Table 29. Natural gas / oil retirements

Unit	State	Capacity (MW)	Announced / Modeled Retirement Date	Unit Type
Brayton Point 4	MA	475.5	June 2017	Steam Turbine
Bridgeport Station 4	CT	18.6	May 2017	Combustion Turbine
MIT Central Utilities/Cogen Plant CTG1	MA	21.2	Apr 2020	Combustion Turbine

Other resources

In AESC 2018, we do not assume any incremental battery storage after 2018. Both Governor Baker's Energy Storage Initiative and stipulations of Massachusetts Chapter 188 require the Massachusetts Department of Energy Resources to determine targets for cost-effective storage additions.[78, 79] However, because AESC 2018 may be used to examine the cost-effectiveness of these resources, we have deliberately excluded them in an effort to avoid double-counting.

Note that our analysis also includes other existing resources not discussed in the above sections. These include conventional hydroelectric resources, pumped-storage hydroelectric resources, and other natural gas-fired and oil-fired resources that are not assumed to exogenously retire during the study period.

Generic non-renewable resource additions

In addition to known and anticipated capacity additions, we allow the EnCompass model to construct generic unit additions of the types represented in Table 30 if it is determined there is a peak demand need. Note that there are two types of each of these generic additions: one type that is built in Massachusetts load zones (and therefore subject to Mass DEP 310 CMR 7.74), and one type that is built in any of the other New England load zones.[80]

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[78] Based on public comments regarding MA DOER's announcement on determination of storage targets, a total of 600 MW of battery storage is proposed to be added in Massachusetts during the study period. Battery storage is assumed to begin being added in Massachusetts starting in 2018, with incremental additions of 50 MW per year until 2019 and 100 MW per year from 2020 through 2024. Battery discharge duration is assumed to increase over time, from 1 hour (as an aggregate average across all battery capacity) in 2018 to 4 hours in 2025. The entirety of the battery systems' capacity is assumed to be available to provide regulation services and to participate in the energy market starting in 2018. Battery capacity is considered "firm," or available to bid into the forward capacity market, once total discharge duration is at least two hours.

[79] Previous Synapse studies have modeled these storage requirements as 200 MWh of battery storage online in Massachusetts by 2020, and 600 MW of battery storage online by 2025.

[80] More information on this environmental regulation can be found in the subsequent section on electricity commodities.

Table 30. Generic unit additions characteristics

	Unit	Natural gas-fired combined cycle	Natural gas-fired combustion turbine
Maximum size	MW	500	330
Minimum size	MW	200	100
Heat rate	Btu/kWh	6,546	9,220
Variable O&M costs	$/MWh	3.5	4.5
Fixed O&M costs	$/kW-yr	60.12	38.52
NO_X emissions rate	lb/MMBtu	0.0075	0.0300
SO_2 emissions rate	lb/MMBtu	0	0
CO_2 emissions rate	lb/MMBtu	119	119

Note: Each type of generic resource may be fueled either with natural gas or fuel oil.
Source: Anchor Power Solutions New England database.

4.5. Transmission, Imports, and Exports

This section describes the existing, under construction, and planned intra-regional transmission modeled in the 2018 AESC Study. It also describes our assumptions on new transmission between New England and other adjacent balancing authorities, and how we modeled imports over these inter-regional transmission lines in the analysis.

Intra-regional transmission

The interface limits used in the 2018 AESC Study reflect both the existing system and the ongoing transmission upgrades discussed in ISO New England's Regional System Plan.[81] The transmission paths that we assumed to link each of the 13 modeled regions in New England are based on those developed by Anchor Power Solutions, and updated to reflect any new or under construction transmission lines planned by the ISO.[82] In EnCompass, transmission lines are grouped and modeled in aggregate.

Inter-regional transmission

In addition, we modeled transmission between subregions of New England and adjacent balancing authorities in New York, Québec, and New Brunswick. As with intra-regional transmission, transmission lines between these regions are typically grouped into aggregate links with aggregate transfer

[81] Regional System Plan documents can be found at https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[82] Note that recent analysis by Synapse which examines large amounts of renewable construction has found that depending on where and how much renewable capacity is built, at a certain point, additional transmission capacity is required to facilitate the movement of renewable generation in northern New England (i.e., areas with favorable wind capacity factors) to Southern New England (i.e., areas of high customer load). At this time, we are not assuming any increases to north-south transmission capacity other than what has been specified by ISO New England's Regional System Plan, but it is possible that we may have to revise this assumption at a later date in order to accommodate high levels of renewables required by state RPS policies.

capacities. These transmission links were developed by Anchor Power Solutions and updated by Synapse to ensure consistency with ISO New England's census of transmission lines.

In addition, AESC 2018 models an incremental 1,000 MW transmission line from Québec to central Massachusetts. This transmission line is not meant to represent any one project; it is instead intended to represent compliance with Massachusetts' 2017 Act to Promote Energy Diversity. Under Massachusetts Chapter 188 Section 83D, Massachusetts distribution utilities were required to solicit, by no later than April 1, 2017, long-term contracts for clean energy generation (including firm service hydro and/or new Class I RPS supply) for a quantity equivalent to 9.45 TWh per year.[83] This clean energy may come either from resources that are currently eligible for compliance with the Class I RPS policy in Massachusetts (including resources located in New England or adjacent control areas) or from new hydroelectricity (including in-region resources, or resources with energy sent over new transmission lines from adjacent control areas). The portion of this energy that is assumed to come from new Class I renewables is described in Chapter 0

[83] Public versions of bids submitted under Section 83D can be found at https://macleanenergy.com/83d/83d-bids/.

Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies.

Any contracts selected from the 83D solicitation process must be executed by no later than December 31, 2022. In this analysis, we assume that this new transmission resource is phased in, starting at 100 MW and 830 GWh on January 1, 2021, 500 MW and 4,150 GWh on January 1, 2022, and 1,000 MW and 8,300 GWh on January 1, 2023 (see Chapter 0

Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies, below, for more detail on this assumption).[84]

Because this cost is assumed to be unavoidable to Massachusetts ratepayers, AESC 2018 does not develop or incorporate a price for this resource at this time.

Imports and exports

Import and export quantities between New England and adjacent balancing areas are represented as fixed, based on recent historical quantities. Anchor Power Solutions has calibrated transfers on these lines such that transfers in historical years match actual historical transfers.

Transmission limits

EnCompass handles interface limits using two separate mechanisms. The first dictates the flow on single pathways, from one zone to another. The second imposes limits on area groups, or models major existing projects. The tables below show the assumptions for each, based on data provided by Anchor Power Solutions.

Table 31. Single pathway transmission limits

Zone A	Zone B	A to B Capacity (MW)	B to A Capacity (MW)
NE Connecticut Northeast	NY G Hudson Valley	800	600
NE Connecticut Northeast	NY K Long Island	333	333
NE Maine Northeast	NE Maine West Central	1,325	
NE Maine Northeast	New Brunswick		1,000
NE Maine Southeast	NE Maine West Central		1,500
NE Maine Southeast	NE New Hampshire	1,900	
NE Massachusetts Central	Hydro Quebec	1,200	2,000
NE Massachusetts West	NY F Capital	800	800
NE Norwalk Stamford	NY K Long Island	428	428
NE Vermont	Hydro Quebec	100	225

[84] Note that these assumptions imply a utilization factor on the transmission lines of 95 percent.

Table 32. Group transmission limits

Transmission Limit	Path	A to B (MW)	B to A (MW)	Notes
NE East-West	NE Massachusetts Central - NE Massachusetts West	3,500	2,200	
	NE New Hampshire - NE Vermont			
	NE Rhode Island - NE Connecticut Northeast			
NE North-South	NE New Hampshire - NE Boston	2,100		A to B: 1/2019: 2,695
	NE New Hampshire - NE Massachusetts Central			
	NE Vermont - NE Massachusetts West			
	Hydro Quebec - NE Massachusetts Central			
NE SEMA/RI	NE Massachusetts Southeast - NE Boston	3,400	3,400	B to A: 6/2018: 786 6/2019: 1,280
	NE Rhode Island - NE Boston			
	NE Rhode Island - NE Connecticut Northeast			
	NE Rhode Island - NE Massachusetts Central			
NE Southeast	NE New Hampshire - NE Boston	10,000		A to B: 6/2019: 5,700
	NE Massachusetts Central - NE Boston			
	NE Rhode Island - NE Connecticut Northeast			
	NE Rhode Island - NE Massachusetts Central			
NE SW CT	NY K Long Island - NE Norwalk Stamford	3,200		
	NE Connecticut Northeast - NE Connecticut Southwest			
NE Connecticut	NE Connecticut Northeast - NY K Long Island	2,950		
	NY K Long Island - NE Norwalk Stamford			
	NE Massachusetts West - NE Connecticut Northeast			
	NE Rhode Island - NE Connecticut Northeast			
	NY G Hudson Valley - NE Connecticut Northeast			
New Brunswick	New Brunswick - NE Maine Northeast	variable	variable	-249 to 989
NY to NE	NY F Capital - NE Massachusetts West	variable	variable	-1,202 to 1,554
	NY D North - NE Vermont			
	NY G Hudson Valley - NE Connecticut Northeast			
Northport	NY K Long Island - NE Norwalk Stamford	variable	variable	-246 to 213
Phase 2	Hydro Quebec - NE Massachusetts Central	variable	variable	-540 to 1,954
Cross Sound	NE Connecticut Northeast - NY K Long Island	variable	variable	-177 to 333
Highgate	Hydro Quebec - NE Vermont	variable	variable	0 to 223

4.6. Embedded Emissions Regulations

This section contains detail on the emission regulations that are embedded in the electric commodity forecast.

The Regional Greenhouse Gas Initiative

All six New England states are founding members of the Regional Greenhouse House Initiative (RGGI). Under the current program design, the six states (along with New York, Maryland, and Delaware) conduct four auctions in each year in which carbon dioxide (CO_2) allowances are sold to emitters and other entities. The amount of CO_2 allowances for each state is determined by legislation or specified by state-specific regulation, and it decreases over time by about 2.5 percent per year. The current program design applies to all years up to and including 2020.

From 2015 through 2017, the RGGI states conducted a 2016 Program Review. Previous program reviews implemented new auction rules and reduced the number of available allowances. In August 2017, the RGGI states announced a set of proposed program changes for Years 2021 through 2030.[85] Under this extended program design, the RGGI states would continue to reduce CO_2 emissions through 2030, eventually achieving a CO_2 emissions level 30 percent below 2020 levels. This proposed program design also put forth a number of changes to the "Cost Containment Reserve" (a mechanism that allows for the release of more allowances in an auction if the price exceeds a certain threshold) and the creation of an "Emissions Containment Reserve" (a mechanism which withholds a number of available allowances if the allowance price remains below a certain threshold).

In September 2017, RGGI Inc. released its preliminary analysis of the new RGGI Program Design.[86] This included projections of a RGGI price through 2030 under three scenarios:

- A **Base Model Rule Policy Case**, which assumes a medium natural gas price, no national program for CO_2, the Pilgrim nuclear power plant retires in 2019, a 1,050 MW transmission line from Canada to New England is built in 2022, medium renewable resource costs, and no explicit assumptions about new offshore wind.
- A **High Sensitivity Model Rule Policy Case**, which assumes a high natural gas price, a mass-based national program for CO_2, the Pilgrim nuclear power plant retires in 2019, no new transmission, high renewable resource costs, and no explicit assumptions about new offshore wind.
- A **Low Sensitivity Model Rule Policy Case**, which assumes a low natural gas price, no national program for CO_2, the Pilgrim nuclear power plant retires in 2019, a 1,050 MW transmission line from Canada to New England is built in 2022 and a second line is built in 2025, low renewable resource costs, and assumes 1,600 MW of offshore wind is constructed over the analysis period.

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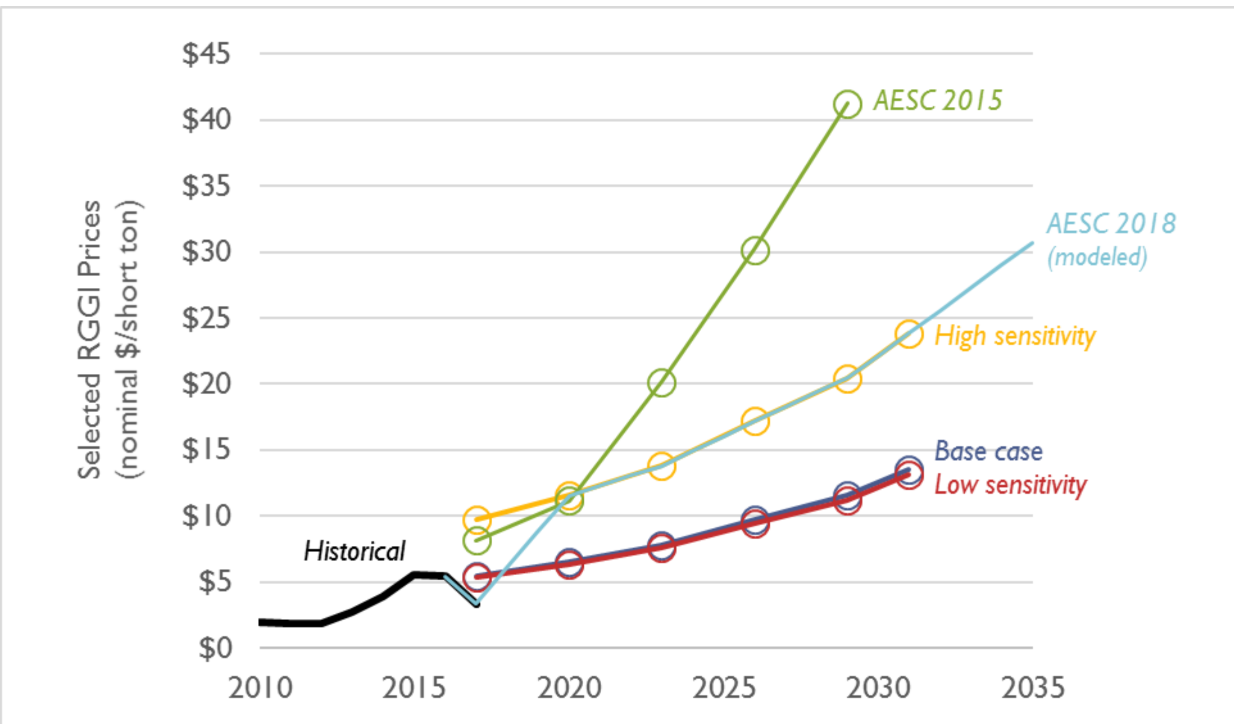
85 The official announcement can be found at http://rggi.org/docs/ProgramReview/2017/08-23-17/Announcement_Proposed_Program_Changes.pdf.

86 See http://rggi.org/design/2016-program-review/rggi-meetings for more information.

The resulting RGGI prices for these three scenarios are shown in Figure 20. This figure also shows the CO_2 allowance price used in AESC 2015, which assumes that mass-based federal regulation of CO_2 is implemented (based on a simulation by SNL Financial of the proposed Clean Power Plan). Given this, it is most directly comparable to the High Sensitivity case, which also assumes a federal, mass-based price on CO_2. Finally, Figure 20 displays the prices for RGGI allowances from auctions in December 2009 through September 2017. In nominal-dollar terms, annual average prices for RGGI allowances have never exceeded $6 per short ton.

Because the RGGI region includes states not modeled in the 2018 AESC study (New York, Delaware, and Maryland), we modeled the effects of RGGI as an exogenous price, rather than a strict cap on emissions. None of the scenarios modeled by RGGI Inc. displayed in Figure 20 exactly represent the assumptions used for the New England electricity system throughout this report. In the AESC 2018 Study, we used a RGGI price trajectory in line with the "High Sensitivity" modeled by ICF on behalf of RGGI, Inc. We chose this price trajectory as it represents a future in which there is no incremental energy efficiency after 2018, implying a higher-than-expected RGGI price.[87]

Figure 20. Historical RGGI allowance prices, recently modeled RGGI allowance prices under by RGGI, Inc, and the RGGI prices applied in AESC 2018 and AESC 2015



[87] Note that the high prices estimated in this sensitivity are due to other changes to the modeled Base Case, including the implementation of a nation-wide carbon price, and they do not directly result from a modeled future where incremental energy efficiency is absent.

Massachusetts Global Warming Solutions Act and MassDEP regulations

AESC 2018 models the GHG regulations finalized by the Massachusetts Department of Environmental Protection (MassDEP) in 2017 in accordance with the Massachusetts Global Warming Solutions Act (GWSA). Under this finalized rule, MassDEP established two regulations that impact the electric sector: 310 CMR 7.74, which establishes a state-specific cap on CO_2 emissions from emitting generators in Massachusetts and 310 CMR 7.75, which establishes a Clean Energy Standard for Massachusetts load-serving entities (LSE). Impacts of these policies in $-per-metric-ton terms are available in *Appendix G. Massachusetts GWSA Regulations Compliance Costs.*

310 CMR 7.74: Mass-based emissions limit on in-state power plants

310 CMR 7.74 assigns declining limits on total annual GHG emissions from identified emitting power plants within Massachusetts. Table 33 lists the affected power plants under this regulation. This table includes existing plants as well as other plants that are under construction and proposed plants expected to be subject to the regulation. In the 2018 AESC study, we modeled this regulation as a state-wide limit through which plants receive CO_2 allowances pursuant to 310 CMR 7.74 at the start of each year.[88] The emissions limit starts at 9.1 million metric tons in 2018. It then declines by 2.5 percent of the 2018 emissions limit to 8.7 million metric tons in 2020, and 6.4 million metric tons in 2030 (see Figure 21).[89]

In this analysis, we assumed that both new and existing units fall under the same aggregate limit. We modeled all new and existing units as able to fully trade allowances pursuant to 310 CMR 7.74 throughout each compliance year. To simplify computation, we did not model any Alternative Compliance Payments (ACP) or banking of CO_2 allowances pursuant to 310 CMR 7.74.

[88] We understand that allowances may be distributed through free allocation, through an auction, or through some combination thereof. We do not make a distinction between these approaches in the 2018 AESC study, as the approach is unlikely to substantially impact allowance prices.

[89] Under the regulation, the emissions cap continues through 2050.

Figure 21. Analyzed electric sector CO_2 limits under 310 CMR 7.74

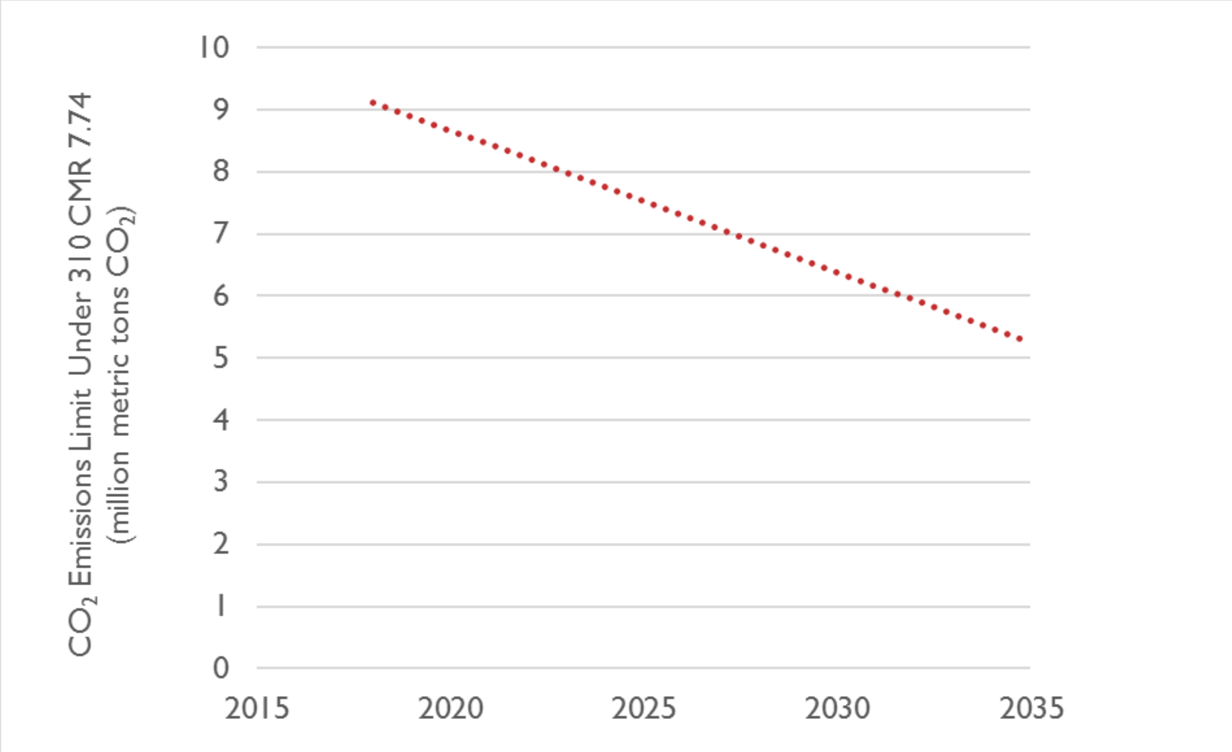


Table 33. List of generating units to be subject to 310 CMR 7.74

ORSPL	Facility	Unit Type	Fuel Type	Online Year (if new)	EnCompass Unit Name
1588	Mystic	ST	Natural Gas	-	Mystic 7
1588	Mystic	CC	Natural Gas	-	Mystic CC
1592	Medway Station	GT	Oil	-	West Medway Jet
1595	Kendall Green Energy LLC	ST	Natural Gas	-	Kendall Square Jet
1595	Kendall Green Energy LLC	CC	Natural Gas	-	Kendall Square CC
1599	Canal Station	ST	Oil	-	Canal 1
1599	Canal Station	ST	Oil	-	Canal 2
1642	West Springfield	ST	Oil	-	West Springfield 3
1642	West Springfield	GT	Natural Gas	-	West Springfield 10
1642	West Springfield	GT	Natural Gas	-	West Springfield 1-2
1660	Potter	CC	Natural Gas	-	Potter Station 2
1660	Potter	GT	Natural Gas	-	Potter Station 2 GT
1678	Waters River	GT	Natural Gas	-	Waters River 1
1678	Waters River	GT	Natural Gas	-	Waters River 2
1682	Cleary Flood	ST	Oil	-	Cleary-Flood
1682	Cleary Flood	OT	Natural Gas	-	Cleary-Flood CC
6081	Stony Brook	CC	Oil	-	Stony Brook CC
6081	Stony Brook	GT	Oil	-	Stony Brook GT
10307	Bellingham	CC	Natural Gas	-	Bellingham Cogen
10726	MASSPOWER	CC	Natural Gas	-	Masspower
50002	Pittsfield Generating	CC	Natural Gas	-	Pittsfield
52026	Dartmouth Power	CC	Natural Gas	-	Dartmouth Power CC
52026	Dartmouth Power	GT	Natural Gas	-	Dartmouth Power GT
54586	Tanner Street Generation, LLC	CC	Natural Gas	-	L'Energia Energy Center
54805	Milford Power, LLC	CC	Natural Gas	-	Milford Power (MA)
55026	Dighton	CC	Natural Gas	-	Dighton Power
55041	Berkshire Power	CC	Natural Gas	-	Berkshire Power
55079	Millennium Power Partners	CC	Natural Gas	-	Millennium Power
55211	ANP Bellingham Energy Company, LLC	CC	Natural Gas	-	ANP Bellingham
55212	ANP Blackstone Energy Company, LLC	CC	Natural Gas	-	ANP Blackstone
55317	Fore River Energy Center	CC	Natural Gas	-	Fore River
1626	Footprint (Salem Harbor)	CC	Natural Gas	2017	Salem Harbor CC
1599	Canal 3	GT	Natural Gas	2019	Canal GT
59882	Exelon West Medway II LLC	GT	Natural Gas	2018	West Medway II

310 CMR 7.75: Clean Energy Standard

This regulation establishes a new “tranche” of clean energy that is eligible to qualify for Clean Energy Certificates. More information on how we modeled this regulation as embedded in the avoided energy cost can be found in Chapter 0

Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies.

Other environmental regulations

Several other environmental regulations were modeled in EnCompass and are thus embedded in the avoided energy costs. Other environmental regulations not included in the avoided energy costs include:

Sulfur dioxide (SO_2) and nitrogen oxides (NO_X)

Allowance prices are applied for annual SO_2 emissions covered under the Cross-State Air Pollution Rule (CSAPR) and the Acid Rain Program (ARP). Actual allowance prices from 2015 ($0.50) for SO_2 are escalated at the rate of inflation through the study period (see Table 34). These assumed prices are in line with the prices assumed in AESC 2013 ($0 per short ton, in 2013 dollars) and AESC 2015 ($1.11 per short ton, in 2015 dollars).

Note that, in AESC 2018, we assumed no NO_X prices. This assumption stems from three factors: the New England states being exempt from the CSAPR program; an assumption that currently proposed state-specific regulations in Massachusetts and Connecticut on ozone-season-NO_X are unlikely to be binding; and NO_X prices having been excluded from modeling in the update to the 2015 AESC study.

Table 34. Emission allowance prices per short ton (constant 2018 $ and nominal dollars)

	SO_2	
	2018 $	*Nominal $*
2018	$0.52	$0.52
2019	$0.52	$0.54
2020	$0.52	$0.55
2021	$0.52	$0.56
2022	$0.52	$0.57
2023	$0.52	$0.58
2024	$0.52	$0.59
2025	$0.52	$0.60
2026	$0.52	$0.61
2027	$0.52	$0.63
2028	$0.52	$0.64
2029	$0.52	$0.65
2030	$0.52	$0.67
2031	$0.52	$0.68
2032	$0.52	$0.69
2033	$0.52	$0.71
2034	$0.52	$0.72
2035	$0.52	$0.73

Mercury

As in past AESC studies, we assumed no trading of mercury and no allowance prices.

Other state-specific CO_2 policies

Similar to Massachusetts GWSA, all other New England states have specified a goal or target for reducing CO_2 emissions (see Table 35). Unlike Massachusetts, no other state has currently issued specific regulations aimed at requiring that emissions remain under a specified cap in some future year. In the 2018 AESC analysis, we did not include any embedded costs of GHG reduction compliance from states other than Massachusetts, and we assumed no additional electric-sector regulations than those put forth under 310 CMR 7.74 and 7.75.[90]

Table 35. State-specific GHG emission reduction targets 2050

State	2050 Target	Sources
Connecticut	80% below 2001	C.G.S. 22a-200a (enacted by H.B. 5600) (https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098- R00HB-05600-PA.htm)
Maine	75–80% below 2003	"Long-term" target; date not specified: Maine Rev. Stat. ch. 3-A §576(3) (enacted by PC 2003, C. 237) (http://legislature.maine.gov/statutes/38/title38sec576.html)
Massachusetts	80% below 1990	Mass.Gen.L. ch. 21N §3(b) (https://malegislature.gov/Laws/GeneralLaws/PartI/TitleII/Chapter21N/Section3)
New Hampshire	80% below 1990	2009 New Hampshire Climate Action Plan (http://des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan /documents/nhcap_final.pdf)
Rhode Island	80% below 1990	Resilient Rhode Island Act of 2014, Sec. 42-6.2-2 (http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM)
Vermont	75% below 1990	10 V.S.A. § 578 (enacted by S. 259) (http://www.leg.state.vt.us/docs/legdoc.cfm?URL=/docs/2006/acts/ACT168.HTM)

Federal CO_2 policies

In 2014, the U.S. Environmental Protection Agency (EPA) published a draft regulation under Section 111(d) of the Clean Air Act. This proposed regulation, known as the "Clean Power Plan" was to be the first-ever federal level-regulation aimed at reducing CO_2 emissions from the electric sector. A final version of the rule was promulgated in October 2015. The final Clean Power Plan did not set a price on

[90] Note that the 2018 AESC study does not assume that the full costs of the Massachusetts GWSA are embedded in the energy prices and CES compliance prices. AESC 2018 only models the cost of compliance associated with regulations promulgated by MassDEP, including 310 CMR 7.74 and 310 CMR 7.75. In reality, the full cost of the Massachusetts GWSA will also be driven by (a) other, modeled impacts to the electric sector (i.e., new unit retirements, unit additions, natural gas prices, load forecasts) and (b) explicitly non-modeled impacts to the electric sector (i.e., energy efficiency and other DSM programs), (e) emission-reducing actions that occur outside the electric sector, and will be bounded by (c), the interim targets for specific milestone dates, which are not yet established.

CO_2 per se; instead, compliance with the rule would result in an "effective" price of CO_2. There have been a wide range of estimated costs of compliance for the Clean Power Plan—the 2015 AESC study relied on analysis by SNL Financial of the proposed rule, which found a nationwide compliance cost of about $31 per short ton in 2029. In Synapse's 2016 Carbon Dioxide price forecast, compliance costs (for the final Clean Power Plan) were estimated to be between $23 and $43 per short ton in 2030.[91] More recently, modeling by RGGI, Inc. has found that 2029 compliance costs with a final, nationwide version of the Clean Power Plan could be as low as $6 per short ton.[92]

In February 2016, the U.S. Supreme Court issued an unprecedented stay on the final Clean Power Plan, preventing the regulation from moving forward while it was still in development and being challenged in lower courts. In October 2017, the EPA, under direction from a new Presidential administration, officially announced its withdrawal of the Clean Power Plan. Under the "endangerment finding," which resulted from the U.S. Supreme Court case *Massachusetts v. EPA* (2005), EPA is still obligated to issue regulations for CO_2, although currently it is unclear what form those regulations will take, or when they will be put forth. As of October 2017, the EPA has announced that it is seeking industry input on revised CO_2 regulations and that they will be forthcoming at some later date.

[91] Synapse's 2016 Carbon Dioxide Price Forecast is available at http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf.

[92] See http://rggi.org/docs/ProgramReview/2017/09-25-17/Draft_IPM_Results_Model_Rule_High.xlsx.

5. Avoided Capacity Costs

AESC 2018 develops avoided capacity prices for annual commitment periods starting in June 2018. The avoided capacity costs are driven by actual and forecast clearing prices in ISO New England's Forward Capacity Market. The forecast prices are based on the experience in recent auctions and expected changes in demand, supply, and market rules. These prices are applied differently for cleared resources, non-cleared energy efficiency, and non-cleared demand response. This section contains background information and findings relevant to avoided capacity costs.

On a 15-year levelized basis, the 2018 AESC forecast is 48 percent lower than what was estimated in the 2015 AESC study for the same years. Specifically, AESC 2015 assumed that the (at the time) existing capacity surplus would rapidly disappear, bringing the capacity price close to ISO New England's estimate of net CONE.[93] While the capacity surplus did disappear, the subsequent capacity auction (FCA 9) cleared well below the previous estimates of net CONE, and the market price fell substantially in the next few years. Since AESC 2015, a large amount of capacity has been added, and ISO New England has reduced its estimate of CONE and shifted the demand curve; these factors have again created substantial surplus capacity. Due to changes in the market structure (particularly CASPR), along with expected state-mandated procurement of a large amount of clean energy capacity, retiring major generation is likely to be replaced by renewable resources. Generators will have strong incentives to avoid abrupt retirement, making price spikes (as observed in FCA 8 and 9) less likely.

5.1. The History and Structure of the ISO New England Capacity Market

The ISO New England capacity auctions have been through three periods since they were instituted in 2008. The prices in FCA #1 (for 2010/11) through FCA #6 (for 2015/16) were determined by administratively determined floor prices. The next two auctions constitute a transition period:

- In FCA#7, NEMA lacked sufficient capacity to provide a competitive market, and the ISO imposed separate ceiling prices for new and existing resources, while the rest of the pool (ROP) still cleared at the floor price.
- In FCA #8, following a large amount of retirements (including the surprise announcement of the 1,500 MW Brayton Point plant just before the deadline for qualifying to bid in the auction), all of New England experienced insufficient competition, and the ISO set ceiling prices.

[93] CONE is the "Cost of New Entry," or the estimated capacity price required for a new power plant to come online.

In FCA 9 (for 2018/19) through FCA #12 (for 2021/22), the auctions finally cleared at competitive market prices, rather than administrative floors or ceilings. Even in FCA #9, the combined SEMA/RI zone experienced insufficient competition, despite the ROP clearing at a competitive price.

Table 36 shows the ROP results for each round of each of the last four auctions. As price falls, ISO New England increases the level of "demand," i.e., the amount of capacity it deems appropriate to procure. Simultaneously, the amount of supply that would clear falls with the price, and the excess of supply over demand falls even faster.

Table 36 also shows that new gas-fired combined-cycle and combustion turbine units cleared in FCAs 9 and 10 at prices well below ISO New England's estimates of the cost of new capacity net of energy and ancillary revenues (net CONE). For FCA #12, ISO New England lowered its estimate of net CONE to the middle of the range of the clearing prices in FCAs #9 and #10; FCA #12 ended with a price about 40 percent below net CONE, yet one new gas combustion turbine (owned by the Massachusetts Municipal Wholesale Electric Company) still cleared.

Table 36. FCA results by round, Net CONE and major new gas plants cleared

	Round	Net CONE	Rounds					Cleared New Gas Units in ROP	
			1	2	3	4	5	Units	MW
FCA 12	$/kW-mo	$8.04	$10.50	$8.00	$5.50	$4.63			
	Demand		33,361	33,731	34,626	35,030			
	Excess		3,972	3,589	2,666	0			
	Supply		37,333	37,320	37,292	35,030		1	58
FCA 11	$/kW-mo	$11.08	$14.50	$11.50	$8.50	$5.50	$5.297		
	Demand		33,786	34,091	34,475	35,789	36,134		
	Excess		4,072	3,727	3,266	748	0		
	Supply		37,858	37,818	37,741	36,537	36,134		
FCA 10	$/kW-mo	$10.81	$14.50	$11.50	$8.50	$7.03	-		
	Demand		33,719	34,409	35,099	35,788	-		
	Excess		3,531	2,830	1,733	0	-		
	Supply		37,250	37,239	36,832	35,788	-	3	1,302[94]
FCA 9	$/kW-mo	$11.64	$14.00	$11.00	$9.551	-	-		
	Demand		33,713	34,373	35,032	-	-		
	Excess		1,907	1,193	0	-	-		
	Supply		35,620	35,566	35,032	-	-	3	835

[94] One of these units, the 485 MW Burrillville 3 combined-cycle (also known as Clear River Energy Center 1), has not yet received approval from the Rhode Island Energy Facility Siting Board. If the unit cannot be in service by June 2019, the owner (Invenergy) will need to find other resources to provide that capacity.

Table 37 shows the change in price per megawatt change in the excess capacity, for each round of the auctions.

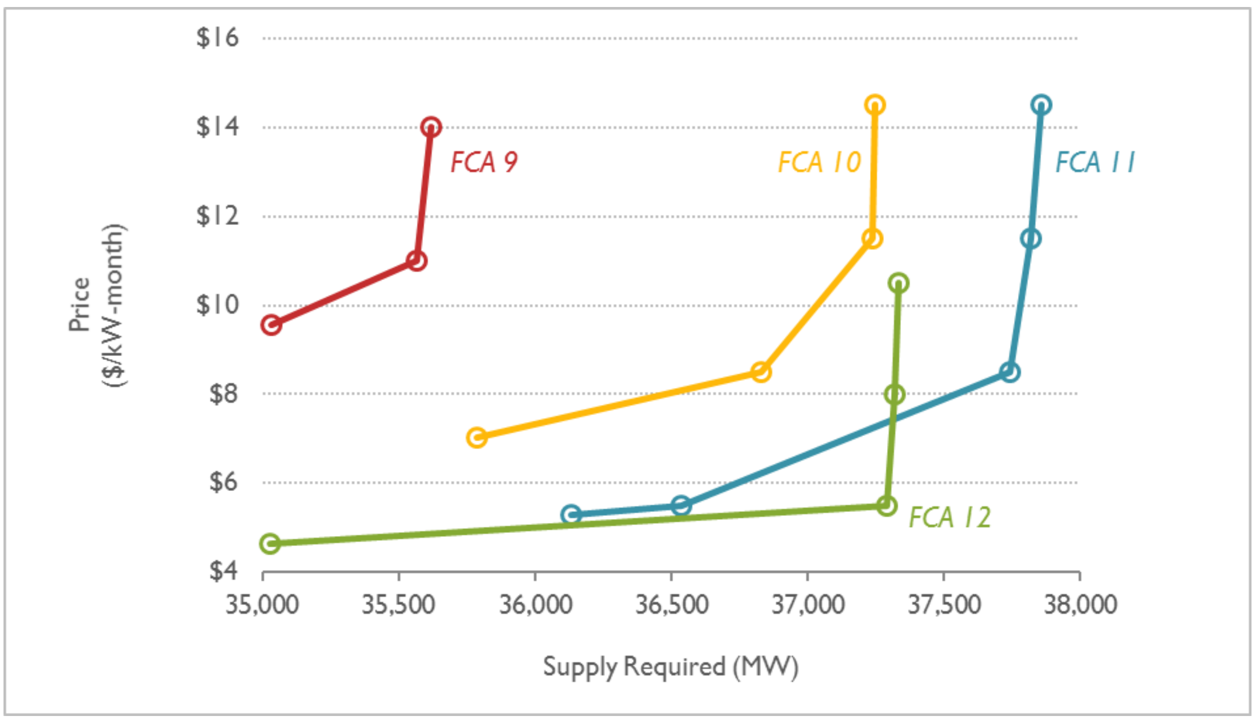
Table 37. Slope of FCA results by round ($/kW-month per MW of excess supply)

	Slope from Round			
	1 to 2	**2 to 3**	**3 to 4**	**4 to 5**
FCA #12	$0.0065	$0.0027	$0.0003	
FCA #11	$0.0087	$0.0065	$0.0012	$0.0003
FCA #10	$0.0043	$0.0027	$0.0008	
FCA #9	$0.0042	$0.0012		

5.2. Supply Curves

Figure 22 presents the ROP price and supply data from Table 36 as supply curves for each of the last four auctions. The shift in the supply curve to the right is partially a result of increased clearing of energy efficiency resources, which would not occur in the AESC base case. Each year, the market has been able to provide more capacity at a given price, or provide a given capacity at a lower price. In the future, further changes in ISO rules and procedures, such as in the stringency of resource qualification and the limits on import capacity, will continue to affect the supply curve.

Figure 22. FCA supply curves



5.3. ISO New England's Competitive Auctions with Sponsored Resources Initiative

One such change is ISO New England's initiative (recently approved by FERC) to change the manner in which new FCA resources demonstrate that they are not bidding below costs.[95] Presently, resources can count as offsets to their costs the expected revenues from the ISO energy, capacity, and ancillary markets.[96] ISO New England's proposal for "Competitive Auctions with Sponsored Policy Resources" (CASPR) will, starting with FCA 13, limit the non-ISO payments used in justifying the FCA bid to the RECs that are available to all qualifying resources. CASPR would thus prevent new capacity from clearing under Massachusetts's SMART program for distributed solar, as well as a number of major renewable or clean projects that will be supported by new contracts with utilities under the Multi-State Clean Energy RFP (which has selected 246 MW of solar and 126 MW of wind projects, to be divided among Massachusetts, Connecticut, and Rhode Island), the Massachusetts 83C process (which aims to bring online 1,600 MW of offshore wind by 2027) and the Massachusetts 83D RFP (which originally selected the Northern Pass transmission line, totaling 1,090 MW).[97] If these sponsored resources were allowed to clear in the FCA, the capacity price would be pushed much lower, preventing the clearing of new market-based resources and potentially leading to the retirement of otherwise viable existing generation.

The CASPR solution treats the existing FCA as the first stage of a two-stage process. After the capacity supply obligations are determined in the primary auction, without participation of the sponsored resources, the ISO will run a substitution auction in which cleared generation resources can retire and buy out of their capacity supply obligations, by paying the sponsored renewable or green resources. For example, if an FCA clears at $6/kW-month, a cleared generator might offer to pay up to $4/kW-month to get out of a capacity supply obligation. The substitution auction may clear at $1/kW-month, in which case the retiring generator will be paid $5/kW-month for doing nothing in the delivery year. The substitution auction could even clear at a negative price, in which case the retiring resource would be paid more for not performing in the delivery year than for delivering capacity. The ISO considers the gain to the retiring generator a "severance payment" for giving up its place in the ISO markets.

The retiring resource must give up its transmission interconnection rights and permanently retire from all ISO markets.[98] The substituted sponsored resource will be treated in the future as though it had cleared in the FCA, and it will be able to bid into future FCAs as an existing resource. The prospect of

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[95] See https://www.ferc.gov/CalendarFiles/20180309230225-ER18-619-000.pdf for details on FERC's approval of CASPR.

[96] The ISO has allowed up to 200 MW of new renewable technology resources (RTR) that do not meet the minimum-price rule to clear in the market in each FCA, starting with FCA 9. The CASPR rules would eliminate that RTR provision.

[97] That line was later rejected by the NH Site Evaluation Council, but Massachusetts was offered several similar transmission lines and other clean resources. A large amount of capacity is likely to be procured through this process.

[98] Only existing generation resources with transmission interconnection rights would be able to discharge their capacity supply obligations in the substitution auction.

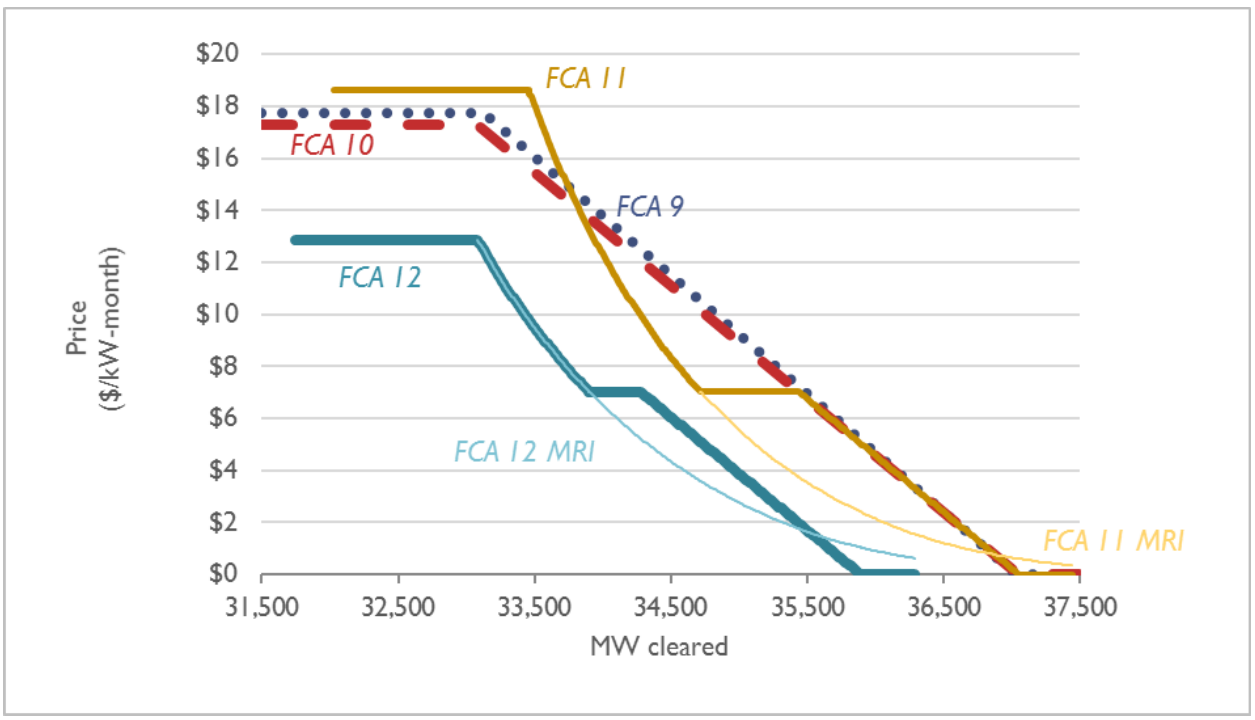
receiving capacity revenues for many years into the future may result in the sponsored resource bidding a substantial negative price in the substitution auction, such as paying $5/kW-month for one year to receive the market price indefinitely.

One effect of the CASPR rules will be to create incentives for marginally viable existing generators to bid to clear in FCA 13 (or later, if the initial supply of sponsored resources is too small) with the intention of selling the capacity supply obligation in the substitution auction. The stock of existing transmission-connected generator capacity supply obligations may never retire, since they can be profitably transferred to sponsored resources.

5.4. Administrative Demand Curves

Figure 23 shows the administrative demand curves set by ISO New England for FCAs 9 to 12. FCAs 9 and 10 used linear demand curves, while FCAs 11 and 12 use a three-part demand curve, comprising (from left to right) a portion proportional to the estimated Marginal Reliability Impact (MRI), a flat connector, and a linear portion. After FCA 13, the ISO plans to use a demand curve entirely proportional to MRI; that shape is also shown for FCA 11 and 12 in Figure 23. While it appears that the MRI-based demand curves will be lower over most of the price range than the linear or partially linear curves of the last three auctions, the ISO is likely to continue adjusting the demand-curve formula.

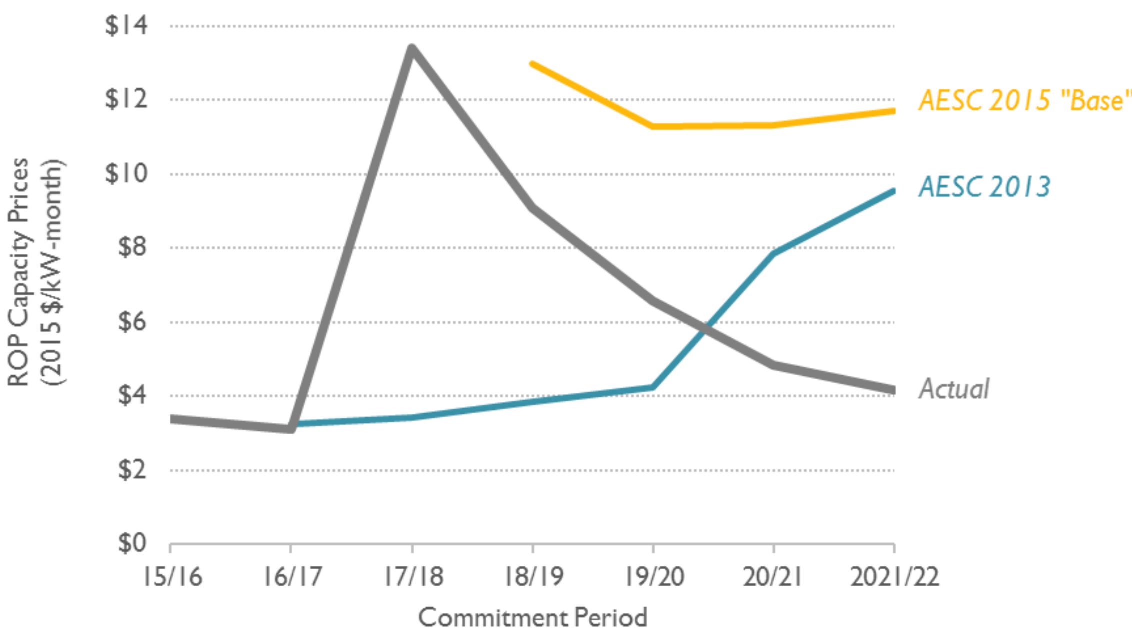
Figure 23. ISO New England-wide capacity demand curves



5.5. Capacity Price Forecast

As shown in Figure 24, neither AESC 2013 nor AESC 2015 did a particularly good job of forecasting the actual capacity prices.[99] Forecasts of capacity prices have been defeated by changes in the market rules and availability of new resources, as well as unexpected retirements.

Figure 24. Comparison of ROP capacity prices, forecasts and actual



This current analysis relied on the results of the last four auctions, which cleared at bid prices, rather than administrative floor or ceiling prices. Our assumptions included the following:

- Resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 12. Most existing resources (renewables, nuclear, hydro, combined-cycle, and modern combustion turbines) continue to bid in as price-takers, at or below likely FCM clearing prices.
- The CASPR rules will be approved and implemented substantially as proposed.
- After FCA 12, most retirements of fossil plants (mostly steam and old combustion turbine units) and potentially nuclear plants will be through the substitution auction, with sponsored resources (initially Massachusetts solar and the Multi-State Renewables, later resources from the Massachusetts 83C

[99] Since the AESC avoided costs assume no energy efficiency programs, the forecasts in 2013 and 2015 would ideally have been somewhat higher than the actual FCA results.

and 83D processes, later Connecticut procurements, and potentially utility-owned renewables and storage).

- Since abrupt retirement of a large amount of capacity might mean that the owner could not obtain a severance payment through CASPR, generation owners are likely to attempt to spread out retirements.
- Load growth in the AESC Reference case would exceed net additions of firm capacity from generator uprates and deratings, renewable additions that can meet the ISO bid thresholds (mostly onshore wind), imports, demand response additions and retirements, and retirement of existing demand response resources and generators attached to the distribution system (and thus not able to participate in the CASPR substitution auction).
- Zonal separation is unlikely, except in the event of concentrated retirements in a single zone.

The capacity prices would have been higher in FCAs 9 to 12 if the post-2017 energy efficiency resources (whose value is estimated in the report) had not existed. Unfortunately, ISO New England reports bid and cleared demand-resources in terms of how their capacity is measured (under rules for real-time, seasonal-peak and on-peak resources), rather than by technology. Many individual demand-side resources can be classified easily (because the resource name specifies energy efficiency, combined heat and power (CHP), solar, or fuel cell), but others are a mix of distributed generation, energy efficiency, and load management, or are simply identified as “other demand resources.”

Removing the growth in energy efficiency resources would increase prices slightly, as summarized in Table 38. In FCA 11, the auction would have ended in round 4; the number of rounds would not be affected for the other two FCAs.

Table 38. FCA prices in the AESC Reference case (2018$/kW-month)

	Clearing Price	New EE MW Since FCA #8	Clearing Price without EE
FCA 12	$4.363	1,134	$4.740
FCA 11	$5.091	804	$5.351
FCA 10	$6.892	472	$7.285
FCA 9	$9.551	217	$9.815

In FCA 12, the demand curve shifted roughly 900 MW to the left compared to the FCA 11 demand curve, as shown in Figure 23. But the FCA 12 supply curve moved about 400 MW to the left of the FCA 11 supply curve, probably due to the increase in the performance payment rate (the penalty for not being able to perform when supply is tightest) by $1,500/MWh in FCA 12.[100] The decline in price from FCA 11 to FCA 12 was almost entirely due to the change in the demand curve.

In the absence of new energy efficiency programs, the 2017 CELT forecast projects annual load growth of about 250 MW, which would shift the demand curve (including the reserve requires in the net installed capacity requirement) right by about 300 MW annually. We assumed that the supply curve will stay fairly steady (barring additional rules changes), except for another $1,955/MWh increase in the performance payment rate in FCA 15. Extrapolating from the change in the FCA 12 supply curve, the FCA 15 supply curve will move left by another 520 MW.

Starting in FCA 13, the CASPR proposal would eliminate new Massachusetts solar (plus some other small renewable resources and resources procured by state-sponsored RFPs), other than as substitutes for retiring generation, reducing the chance of large rightward shifts of the supply curve.[101] We assumed that the addition of small unsubsidized generators and uprating of existing units will balance deratings of other units, and that additions and retirements of demand-response resources will also roughly balance.

Without new energy efficiency programs after 2017, the demand curve would shift rightward about 300 MW annually, which would raise the market-clearing price by about $0.10/kW-month (in 2018$) each year from FCA 13 (2022) onward; the leftward shift of the supply curve in FCA 15 would add another $0.18/kW-month that year. By FCA 16 (2025), the capacity price would be in the steeper portion of the supply curve, above $5.50/kW-month in FCA 12 dollars (2021$) or $5.18/kW-month in 2018$. The price would then rise about $0.47/kW-month each year, until it reached the price at which major new generation would be added. Given the limited experience with competitive FCA results, as well as the potential for changes in market rules and in the energy markets (which help to determine capacity prices), selecting that price is speculative. Based on the results in FCAs 9 and 10, and the FCA 12 CONE of $7.58/kW-month in 2018 dollars, we selected $7.50/kW-month in 2018 dollars as the estimated price that would start to bring in major generation. The capacity market would reach that price in FCA 20 (the summer of 2029).[102]

Once the price reached the cost of new generation, we assumed that about 600 MW of new major capacity will come online over two years, pushing the capacity price down to $6.60/kW-month. After this, the price would rise and trigger another round of construction. The delayed construction and extended addition of new generation follows the general pattern of the last several FCAs, in which high

[100] In the AESC reference world, the FCA 12 supply curve was 1,130 MW further to the left, due to the removal of the FCA 9 to 12 energy efficiency resources.

[101] Comparable projects cleared in FCAs 9 to 12 under the Renewable Technology Resource (RTR) Exemption from bid-price floors. Only a little over 100 MW of capacity cleared as RTRs in FCA 9 to 11, combined.

[102] If Burrillville #3 is unable to secure required permits and loses its CSO, the initial price increases would be accelerated by a year or so, depending on the mix of capacity acquired to replace Burrillville (e.g., high-priced resources waiting for an opportunity to retire, new DR, imports).

prices in FCA 8 and 9 resulted in large additions in FCA 9 and 10. New generation continued to clear even as prices fell, either because additional resources were able to qualify in the later auctions or because previously qualified resources were able to reduce their bid prices as development progressed.[103]

There is no way to anticipate the exact timing of future capacity price changes, once the capacity price reaches the range required to support new major gas generation. We have forecast the capacity price to vary in the $6.60 to $7.50/kW-month range. There would likely be occasional excursions beyond that level: falling due to over-procurement of lumpy resources, surges in unsubsidized renewables, or falling gross load; and rising due to unexpected load growth, loss of unsubsidized imports (e.g., if New York experiences large retirements or Québec anticipates a drought or finds a better customer for its export capacity), or unexpected retirements that exceed the backlog of sponsored projects.

A time series of capacity prices, as well as a 15-year levelized cost for the 2018 AESC study is shown in Table 39. On a 15-year levelized basis, the 2018 AESC forecast is 48 percent lower than the estimates in the 2015 AESC study and 33 percent lower than the estimate in the AESC 2015 Update. The ISO New England allowance for distribution losses (8 percent) must be added to these values.

The load reduction recognized in a particular summer (e.g., cleared or reducing the load forecast for Summer 2018 in FCA 9) receives capacity payments (or reduces capacity responsibility) in June to December of that year and January to May of the next year (e.g., June 2018 to May 2019). A load reduction in the summer of 2018 is thus worth 12 times the 2018/19 price, or $118/kW, spread over that period. The present value of the payment stream is 99.5 percent of the present value of the same monthly payment spread over Calendar Year 2018; for all practical purposes, the benefit of a load reduction in 2018 is 12 times the monthly capacity price.

[103] More new major capacity cleared in FCA 10 at $7.03/kW-month than in FCA 9 at $9.55/kW-month. Bridgeport Harbor 6 qualified in FCA 10, but did not clear, apparently because it bid more than $9.55; it reduced its bid and cleared in FCA 9. The MMWEC peaker qualified and bid more than $5.30/kW-month in FCA 11 but cleared at $4.63/kW-month in FCA 12.

Table 39. AESC 2018 capacity prices (2018 $ / kW-month)

Commitment Period (June to May)	FCA	AESC 2018	AESC 2015	AESC 2015 Update
2018/2019	9	$9.81	$13.60	$9.57
2019/2020	10	$7.28	$11.85	$6.92
2020/2021	11	$5.35	$11.89	$9.12
2021/2022	12	$4.74	$12.29	$8.51
2022/2023	13	$4.84	$12.20	$8.08
2023/2024	14	$4.94	$11.93	$7.53
2024/2025	15	$5.22	$12.55	$8.48
2025/2026	16	$5.65	$12.55	$9.21
2026/2027	17	$6.13	$12.64	$10.13
2027/2028	18	$6.60	$12.37	$10.87
2028/2029	19	$7.07	$13.08	$11.77
2029/2030	20	$7.54	$13.42	$12.66
2030/2031	21	$6.60	-	$14.09
2031/2032	22	$7.07	-	$13.98
2032/2033	23	$7.54	-	-
2033/2034	24	$6.60	-	-
2034/2035	25	$7.07	-	-
2035/2036	26	$7.54	-	-
15-year levelized		$6.42	$12.32	$9.62
Percent Difference (AESC 2018 relative to other studies)		-	-48%	-33%

Notes: All prices are in 2018 $ per month. Levelization periods are 2015/2016 to 2029/2030 for AESC 2015 and 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 2.43 percent for AESC 2015, 1.43 percent for AESC 2015 update, and 1.34 percent for AESC 2018. Dashes in AESC 2015 and AESC 2015 Update refer to years in which capacity prices were extrapolated, rather than modeled. Bolded prices for FCAs 9-12 reflect actual prices stated in 2018$.
Source: AESC 2015 Exhibit 5-32, TCR workbook.

Consumer benefit of load reductions

Any load reduction that clears as a resource in an FCA benefits the program administrator, and generally consumers, in the year that the resource clears. For example, if a program administrator in February 2015 expected to reduce peak load by a MW in the summer of 2018 and bid that amount into FCA 9, it would receive the full value of that load reduction from FCA 9 through the end of the measure's life.

But not all energy efficiency resources are bid into FCAs about three-and-a-half years in advance of the start of the commitment period (CP). Program administrators may choose to claim lower savings from new installations until the program is approved, funding is more certain, or the rate of installation is better known. Thus, a program administrator may bid only a portion of the anticipated savings into the FCA for the commitment period in which the savings are expected (CP1). The remainder can be bid into the annual reconciliation auctions (ARAs) run by ISO New England for CP1, as well as for the FCAs for later commitment periods. In general, the ARA prices are lower than the FCA price; for the ARAs completed for the commitment periods ending in 2017 to 2020, the first ARA averaged about 95 percent of the FCA price, the second ARA averaged 87 percent, and the third ARA averaged 27 percent. Table 40 summarizes the effectiveness of an energy efficiency resource in producing capacity revenue in future commitment periods, as a function of the year the program administrator is willing to bid into the auction. A resource for which bidding is delayed until the year that the resource is expected to enter service (Year 0) would provide only 27 percent of the revenues in that year (CP1), 87 percent in the next year, 95 percent in the third year, and 100 percent for CP4 and after.

Table 40. Effect of delayed resource bidding by bidding year and commitment period

Summers for 2018 EE→		2018	2019	2020	2021	2022	Bidding
Bid years for 2018 EE ⇩	Year	CP1	CP2	CP3	CP4	CP5	Example
2015	–3	100%	100%	100%	100%	100%	40%
2016	–2	95%	100%	100%	100%	100%	20%
2017	–1	87%	95%	100%	100%	100%	20%
2018	0	27%	87%	95%	100%	100%	10%
2019	1	0	27%	87%	95%	100%	10%
Weighted Value for Example:		79.1%	90.4%	98.2%	99.5%	100%	

Table 40 also provides examples for the years in which the program administrator may bid capacity and the summers for which the resource may be counted, to clarify the meaning of the bid year and the summer of the commitment period. In addition, Table 40 shows an example in which the program administrator bids 40 percent of the 2018 savings into FCA 9, then bids another 20 percent into the subsequent year's reconfiguration auction, 20 percent in the next year's reconfiguration auction, and so on.

Program savings that are not cleared as capacity resources provide savings much more slowly. A load reduction in 2018 will first affect the ISO New England's Spring 2019 load forecast, which will be used in the February 2020 FCA 14 for 2023/24. Thus, there is a five-year delay between the load reduction and its first influence on the capacity charges to load.[104]

The ISO forecasts peak load by regressing daily peak load on monthly or annual energy requirements (the ISO documentation is inconsistent), a positive time trend over the years, and weather variables. The forecast of energy requirements is driven by the previous year's energy requirement, economic variables (mostly GDP), electricity price, and weather. Load reductions from energy efficiency measures will reduce both the actual energy used to develop the energy forecast model and the relationship of

[104] Any reduction in a customer's load in the actual peak hour in one summer (e.g., 2018) will reduce the capacity obligation of the customer (or the customers included in the same load profile group, such as the UI residential load group) in the following commitment year (e.g., 2019/20). But it will not reduce the capacity procured. Hence, uncleared load reductions will shift costs to other customers (in the same state and in other states) with a one-year delay. States that do not consider costs and benefits at the regional level (including those that recognize only intrastate DRIPE benefits) would logically treat this capacity-cost shift as a benefit. The same is true for ISO New England charges that are not avoidable but are allocated on energy and/or peak loads (operating reserves, uplift, and other ancillary services).

peak load to energy and time. The 2017 forecast used 27 years of data for the energy regressions and 15 years for the peak regressions, so a load reduction in one year, or a few years, will have little effect on the trend.[105]

While we cannot precisely determine the effect of load reductions on the ISO's complex econometric models and load forecasts, a reasonable estimate would be that the load forecast would reflect the full effect of the load reduction in Year 10 of the reduction. The demand curve would be shifted by the forecast reduction, increased by the loss factor (which the ISO assumes is 8 percent) and the reserve margin. Table 41 shows the phased-in value of capacity for each installation date, including losses and reserve margin.

Table 41. Phase-in of non-cleared load reduction ($/kW-month, 2018$)

Summer	FCA	Clearing Price	Reserve margin	Load Forecast Effect for installations in:			Capacity Cost Avoided by installations in:		
				2018	*2019*	*2020*	*2018*	*2019*	*2020*
2018	9	$9.81	1.168	0%			-		
2019	10	$7.28	1.198	0%	0%		-	-	
2020	11	$5.35	1.221	0%	0%	0%	-	-	-
2021	12	$4.74	1.181	0%	0%	0%	-	-	-
2022	13	$4.84	1.180	0%	0%	0%	-	-	-
2023	14	$4.94	1.179	30%	0%	0%	$1.89	-	-
2024	15	$5.22	1.177	50%	30%	0%	$3.31	$1.99	-
2025	16	$5.65	1.173	70%	50%	30%	$5.01	$3.58	$2.15
2026	17	$6.13	1.169	90%	70%	50%	$6.96	$5.41	$3.87
2027	18	$6.60	1.165	100%	90%	70%	$8.30	$7.47	$5.81
2028	19	$7.07	1.149	100%	100%	90%	$8.77	$8.77	$7.90
2029	20	$7.54	1.146	100%	100%	100%	$9.33	$9.33	$9.33
2030	21	$6.60	1.165	100%	100%	100%	$8.30	$8.30	$8.30
2031	22	$7.07	1.149	100%	100%	100%	$8.77	$8.77	$8.77
2032	23	$7.54	1.146	100%	100%	100%	$9.33	$9.33	$9.33
2033	24	$6.60	1.165	100%	100%	100%	$8.30	$8.30	$8.30
2034	25	$7.07	1.149	100%	100%	100%	$8.77	$8.77	$8.77
2035	26	$7.54	1.146	100%	100%	100%	$9.33	$9.33	$9.33

[105] The PJM load forecasters ran sensitivities on their generally similar regression-based forecasts at the request of the Maryland Office of Peoples Counsel. Those sensitivities showed that an equal-percentage load reduction on all hours for three years resulted in a reduction in the forecast by 10 to 30 percent of the load reduction starting by the seventh year (four years after the end of the modeled load reduction).

Avoided capacity costs from uncleared demand response

Any resource—demand response, load management, energy efficiency, or other passive demand resource—that clears in an FCA will have the same capacity benefit per megawatt cleared. The effect of uncleared measures, acting through the load forecast, will have a range of potential effects.

The ISO New England model for forecasting the summer peak uses data from each of the 62 days in July and August for the most recent 15 years. A reduction in the peak hours of one or a few of the latest years will tend to reduce the time-trend coefficient in the model, and reductions on the days with the highest temperature-humidity index values will tend to reduce the THI coefficients. Most energy efficiency measures that reduce the summer peak will have one or both of these effects on the results of the ISO's econometric model.

Some demand-response measures will have a much more modest effect on the forecasting model. Demand response that operates only a few times each summer, in capacity emergencies or at times of high locational marginal energy prices (LMP), may reduce only a few of the peak hours in the summer. They may not even hit the hours with the highest THIs.

The PJM load forecasters ran sensitivities on their econometric forecasting model and found that load reductions on a few high-load days each summer would reduce the load forecast by only about 10 percent of that from an energy efficiency reduction in all hours. Program administrators should model the effect of selective high-hour reductions on the ISO New England load forecast before claiming any avoided capacity costs from those resources. For initial screening, program administrators may wish to credit those measures with 10 percent of the values in Table 41.

Avoided capacity costs from short-term load reductions

Energy efficiency programs generally install equipment that continues to reduce load over its useful life. In contrast, some behavioral, demand-response and load-control programs leave no equipment in place to continue savings past the end of the program. If such a program is expected to remain in place indefinitely, it may be screened using the effects shown in Table 41. But if the program's duration is unclear (especially if it is authorized to operate for only a limited number of years), it would not be expected to have those continuing effects.

For a one-year reduction in 2018, about 30 percent of the load reduction would be reflected in 2023/24 and that effect would decline each year and reach zero in 2028. For a three-year reduction in 2018 to 2020, about 30 percent of the load reduction would be reflected in 2023/24, rising to 70 percent in 2025/26 and falling to zero in 2030 (see Table 42). In Appendix B, these reductions are adjusted to reflect losses and reserve margin.

Table 42. Phase-in and decline of load-forecast effect of short-lived uncleared measures

Year After Start	Incremental Effect from 1 Mw Reduction in Year (%)										Total Forecast Effect for 1 Mw Load Reduction for:									
	N	1	2	3	4	5	6	7	8	9	1 yr	2 yrs	3 yrs	4 yrs	5 yrs	6 yrs	7 yrs	8 yrs	9 yrs	10 yrs
N+5	30										0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
N+6	20	30									0.2	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
N+7	20	20	30								0.2	0.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
N+8	20	20	20	30							0.2	0.4	0.6	0.9	0.9	0.9	0.9	0.9	0.9	0.9
N+9	10	20	20	20	30						0.1	0.3	0.5	0.7	1	1	1	1	1	1
N+10		10	20	20	20	30						0.1	0.3	0.5	0.7	1	1	1	1	1
N+11			10	20	20	20	30						0.1	0.3	0.5	0.7	1	1	1	1
N+12				10	20	20	20	30						0.1	0.3	0.5	0.7	1	1	1
N+13					10	20	20	20	30						0.1	0.3	0.5	0.7	1	1
N+14						10	20	20	20	30						0.1	0.3	0.5	0.7	1
N+15							10	20	20	20							0.1	0.3	0.5	0.7
N+16								10	20	20								0.1	0.3	0.5
N+17									10	20									0.1	0.3
N+18										10										0.10

5.6. Other Wholesale-Load Cost Components

In addition to the locational marginal energy prices and capacity prices, the ISO New England monthly "Wholesale Load Cost Report" includes the following cost components:

- First-Contingency Net Commitment Period Compensation (NCPC)
- Second-Contingency NCPC
- Regulation (automatic generator control)
- Forward Reserves
- Real-Time Reserves
- Inadvertent Energy
- Marginal Loss Revenue Fund
- Auction Revenue Rights revenues
- Price Responsive Demand Cost
- ISO Tariff Schedule 2 Expenses
- ISO Tariff Schedule 3 Expenses

- NEPOOL Expenses

These cost components are described in more detail in the Wholesale Load Cost Reports, available from ISO New England's website, www.iso-ne.com. For 2016, ISO New England's estimates of costs to load (a load with 100 percent load factor) for most zones comprised energy (~81 percent of the total) and capacity costs (~12 percent), first-contingency NCPC (~3.5 percent), forward and real-time reserve (~1.3 percent), regulation (0.6 percent), credits for marginal losses and transmission revenues (~-1 percent), and fees (2.2 percent). In NEMA/Boston, with tight supply and a higher capacity price for much of the year, the capacity cost was 18 percent of the total, and second-contingency NCPC was 3 percent (versus 0.1–0.3 percent in the other zones). In 2017, the capacity prices rise, and the other components fall.

None of these components vary clearly enough with the level of load to warrant inclusion in the avoided-cost computation. More specifically:

- The NCPC costs (by far the largest of these categories, although much smaller than forward capacity charges) are compensation to generators that comply with ISO New England instructions to warm up their boilers, ramp up to operating levels, remain available for dispatch, possibly generate some energy, and then shut down without earning enough energy- or reserve-market revenue to cover their bid costs. Older boiler plants may take many hours to reach full load and have minimum run-times and shut-down periods, requiring plants to continue running at minimum levels overnight. Lower on-peak loads would tend to reduce the need for bringing these plants into warm reserve, thus reducing NCPC costs. On the other hand, lower energy prices (especially off-peak) would tend to increase the net compensation due to these units when they were required, since they would earn less when they actually operated. Hence, while energy efficiency may affect NCPC costs, the direction and magnitude of the effects are not clear.

- Regulation costs are associated with units that follow variations in load and supply in the range of seconds to a few minutes. Reduced load due to efficiency is likely to result in reduced variation in load (in megawatts per minute), reducing regulation costs. On the other hand, some controls may increase regulation costs, if end-use equipment responds more quickly to changing ambient conditions. Overall, energy efficiency programs will probably reduce regulation costs, but we cannot estimate the magnitude of the effect.

- Forward and real-time reserve requirements should decrease slightly with energy efficiency, for two reasons. First, lower load will tend to leave more available capacity on transmission lines, which will tend to reduce the need for local reserves. Second, a portion of real-time reserves are priced to recover forgone energy for units that remain in reserve; lower energy prices will tend to depress reserve prices. We expect that these effects would be small and difficult to measure.

- Inadvertent energy exchanges with other system operators (NY ISO, Hydro Quebec, and New Brunswick) are small and probably not affected by energy efficiency.

- The Marginal Loss Revenue Fund returns to load the difference between marginal losses included in locational energy prices and the average losses actually experienced over the pool transmission facilities. That fund is—by definition—generated by infra-marginal usage, and it will not be affected by reduction of loads at the margin.

- Auction Revenue Right revenues are generated by the sale of Financial Transmission Rights (FTR), to return to load the value of transfers on the ISO transmission facilities. To the extent that efficiency programs reduce energy congestion, the value of these rights will tend to decrease.

- Price Responsive Demand charges recover a portion of the ISO's payments for those demand resources. The use of those resources would tend to fall as peak prices fall, but so would their compensation from the energy markets, potentially increasing this charge. This category is miniscule.

- Expenses (ISO Tariff Schedules 2 and 3 and NEPOOL) are largely fixed for the pool as a whole, although a portion of the ISO tariffs are recovered on a per-MWh basis. Some of the ISO costs may decrease slightly as energy loads decline, if that leads to a reduction in the number of energy transactions, dispatch decisions, and other ISO actions required. Any such effect is likely to be small and slow to occur, and energy efficiency programs add their own costs in load forecasting, resource-adequacy planning, and operation of the forward capacity market.

The NCPC charges are roughly 20 percent of the capacity charges, and the other cost categories are considerably smaller.

6. AVOIDED ENERGY COSTS

This chapter describes the findings associated with avoided energy costs. As a point of comparison, we compare the electric energy prices for the West Central Massachusetts zone between AESC 2018 and AESC 2015.[106] On a levelized basis, the 15-year AESC 2018 annual all-hours price is $49 per MWh, compared to the equivalent value of $59 per MWh from AESC 2015. This represents a reduction of 18 percent.[107] The lower estimate for AESC 2018 is primarily due to a lower estimate of wholesale natural gas prices in New England and a lower estimate of RGGI prices.

6.1. Forecast of Energy and Energy Prices

The AESC 2018 projected level of New England electric system energy from 2018 to 2035 is presented in Figure 25. These energy levels are estimated by the EnCompass model given the capacities specified in Figure 26, fuel prices, availability factors, heat rates, and other unit attributes. Figure 25 assumes a future in which no new energy efficiency is added in 2018 or later years. This figure includes an accounting of energy imports (over both existing and new) transmission lines from electric regions adjacent to New England.

Note that all prices discussed in this chapter are wholesale prices, not retail prices.

[106] This WCMA price also represents the ISO New England Control Area price, which is within this zone.

[107] Relative to the 2015 AESC Update (which had an annual all-hours value for this geography of $50 per MWh), this represents a decrease of 3 percent.

Figure 25. AESC 2018 New England-wide generation, imports, and system demand

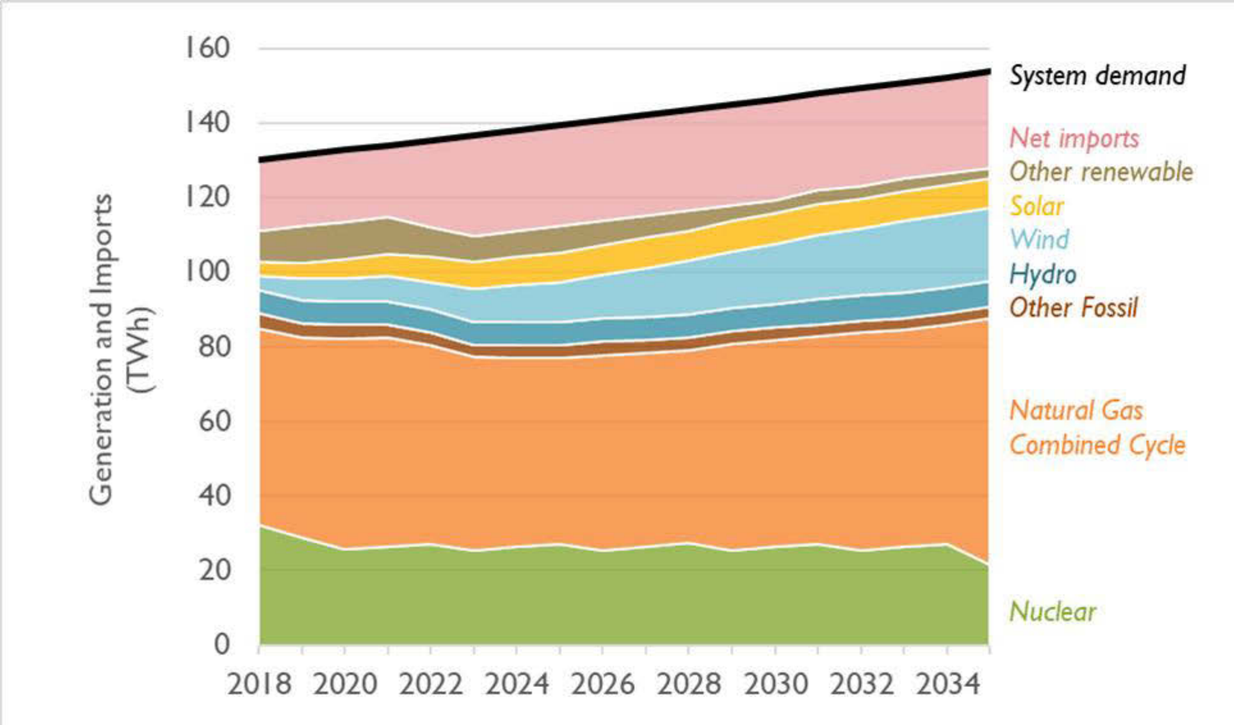
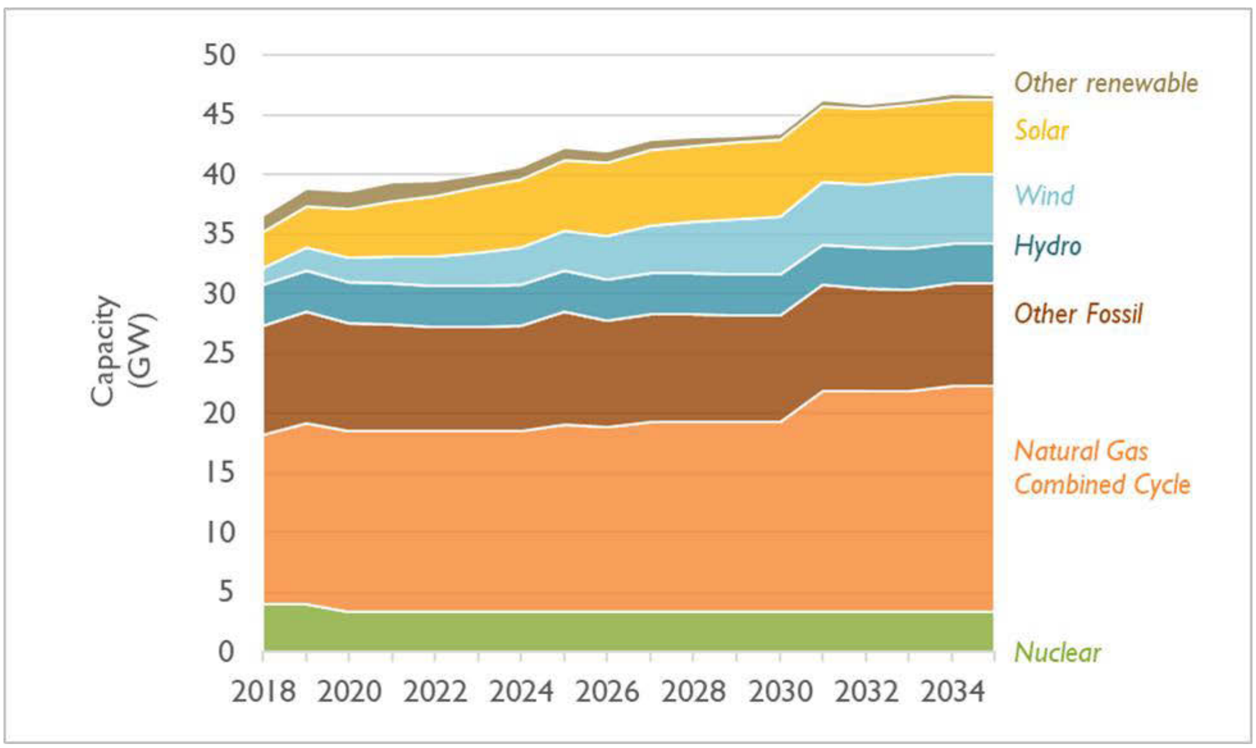


Figure 26. New England-wide capacity modeled by EnCompass



Forecast of wholesale energy prices

In addition to the generation shown in Figure 26, the EnCompass model also produces wholesale energy prices (see Figure 27 and Table 43).[108] These modeled prices change over time (and on a peak and off-peak basis) depending on the system demand, available units, transmission constraints, fuel prices, and other attributes. The change in wholesale energy price from 2018 to 2035 observed in Table 43 is generally lower than the assumed growth in Henry Hub prices described in Chapter 2. This trend is caused by (a) increasing amounts of renewable and imported generation which increasingly displaces higher-cost fossil units, and (b) a lower future Algonquin basis in real-dollar terms, in some months. Year-to-year variations in prices can be traced to impacts associated with the new transmission line in the early 2020s, large quantities of offshore wind in the mid to late 2020s, and a flattening of assumed Henry Hub prices (in real-dollar) terms through the 2030s.

Note that these energy prices are not inclusive of RECs, but are inclusive of modeled environmental regulations that impose a price on traditional generators, including RGGI and 310 CMR 7.74.[109]

[108] This section describes prices for the West Central Massachusetts region (WCMA). WCMA is chosen as a representative region given that it is a proxy for the location of the ISO New England control area. This price effectively represents the hub price for ISO New England, reflecting congestion and losses. Note that all summarized energy prices are calculated using a load-weighted average.

[109] REC prices are provided in Chapter 0.

Figure 27. AESC 2018 wholesale energy price projection for WCMA

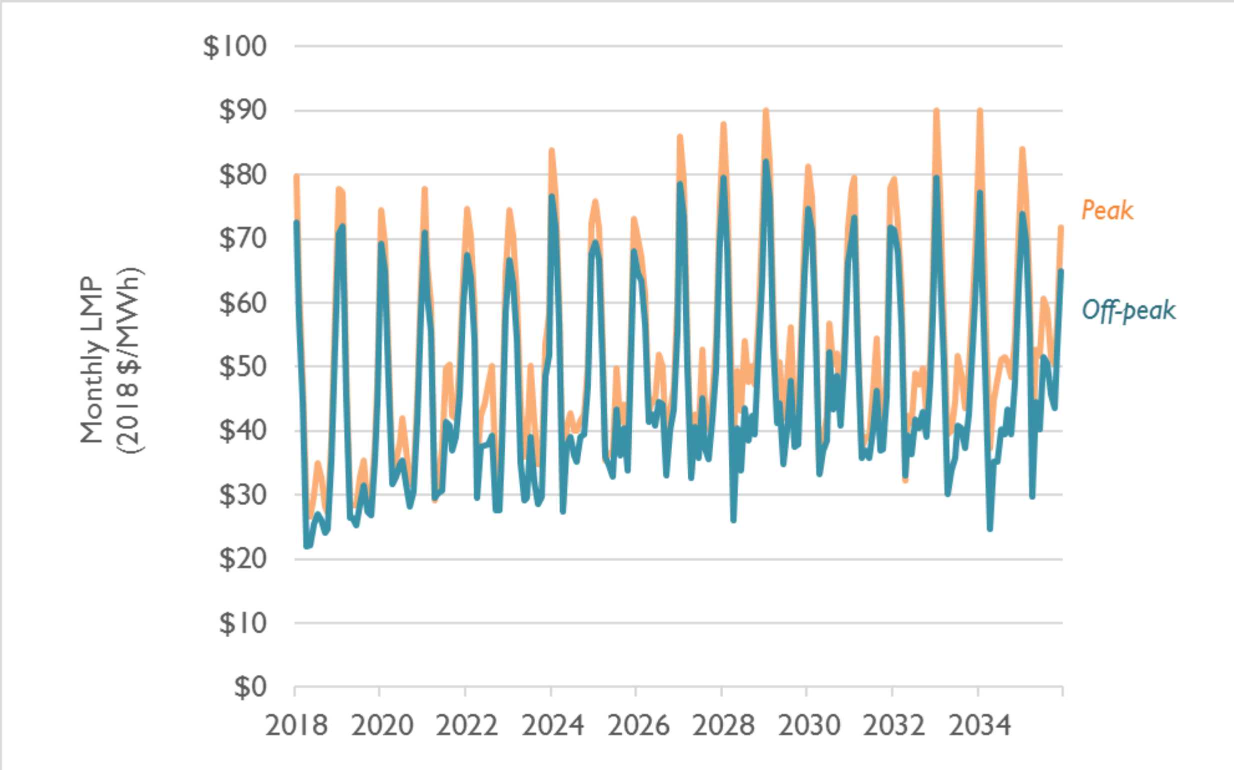


Table 43. AESC 2018 wholesale energy price projection for WCMA region (2018 $ / MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
2018	$39.44	$47.57	$43.35	$31.80	$25.74
2019	$40.60	$48.38	$44.89	$31.69	$28.30
2020	$44.67	$51.75	$48.54	$37.55	$32.63
2021	$48.26	$54.01	$50.37	$45.32	$37.63
2022	$47.19	$53.68	$48.65	$44.53	$35.85
2023	$46.62	$55.04	$48.66	$41.62	$32.62
2024	$50.28	$58.45	$54.73	$41.02	$37.33
2025	$48.95	$55.23	$52.13	$43.01	$38.44
2026	$49.98	$55.35	$51.83	$46.72	$40.85
2027	$52.06	$59.94	$56.01	$44.66	$38.70
2028	$53.19	$61.78	$54.44	$48.81	$39.73
2029	$54.83	$63.62	$58.19	$47.82	$40.41
2030	$53.65	$58.51	$55.15	$50.45	$46.02
2031	$51.30	$58.09	$54.34	$45.76	$39.88
2032	$50.65	$56.74	$52.72	$46.74	$40.41
2033	$52.36	$61.36	$53.81	$47.46	$38.73
2034	$51.89	$60.49	$50.73	$50.44	$39.59
2035	$56.44	$62.55	$55.79	$56.14	$47.43

Comparison to AESC 2015

A comparison of 15-year levelized costs for the WCMA reporting region is shown in Table 44. Prices are shown for all hours, and for the four periods analyzed in previous AESC studies.[110] On an annual average basis, the 15-year levelized prices in the 2018 AESC study are 18 percent lower than the prices modeled in the 2015 AESC study. Key drivers of these lower prices include lower overall demand for electricity (even in a future with no incremental energy efficiency), lower Henry Hub natural gas prices, lower RGGI prices, more renewables (caused by changes to the RPS in states like Connecticut and Rhode Island), and the addition of a new transmission line from Canada.[111] This decrease is similar to the change in avoided energy costs observed between the 2013 AESC study and the 2015 AESC study.

In particular, AESC 2018 modeling results feature a lower ratio of summer peak prices to the annual average than observed in previous AESC studies; this difference can be attributed to: (1) increased levels of solar generation, which is largely coincident with this period and which have a marginal cost of zero dollars per MWh, (2) difference in month-to-month wholesale gas costs (which are driven by new recent historical data on month-to-month gas costs), and (3) higher levels of zero-marginal cost imports.

[110] Note that prices discussed in this document are prices produced from modeling runs completed at the "traditional" AESC temporal resolution—i.e., monthly and peak/off-peak, although costs have been calculated at an 8,760-hour resolution.

[111] Other factors, including the Massachusetts-specific emissions cap under MA DEP 310 CMR 7.74 and a lower discount rate, push the avoided costs observed in AESC 2018 up, but not enough to overcome the impact of the other factors mentioned above.

Table 44. 15-year levelized cost comparison for WCMA region (2018 $ / MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2015	$59.38	$65.18	$59.64	$60.54	$47.27
AESC 2015 Update	$53.88	$60.87	$52.81	$52.78	$40.42
AESC 2018	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2015 Pcnt Diff	-18%	-15%	-14%	-29%	-22%
AESC 2015 Update Pcnt Diff	-10%	-9%	-3%	-19%	-9%

Notes: All prices have been converted to 2018 $ per MWh. Values for the AESC 2015 represent a regionwide average, and are not shown for WCMA specifically. Levelization periods are 2016–2030 for AESC 2015, 2017–2031 for AESC 2015 Update, and 2018–2032 for AESC 2018. The real discount rate is 2.43 percent for AESC 2015, 1.43 percent for AESC 2015 Update, and 1.34 percent for AESC 2018. Source: AESC 2015 Exhibit 1-5, TCR workbook.

Table 45 compares 15-year levelized costs between AESC 2015 and AESC 2018 for each of the six New England states. These values incorporate the relevant renewable energy certificate (REC) costs, as well as a wholesale risk premium of 8 percent.

Table 45. Avoided retail energy costs, AESC 2018 vs. AESC 2015 (15-year levelized costs, 2018 $ / kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	1	Connecticut	$0.065	$0.060	$0.050	$0.044
	2	Massachusetts	$0.064	$0.059	$0.050	$0.044
	3	Maine	$0.059	$0.055	$0.046	$0.040
	4	New Hampshire	$0.065	$0.061	$0.052	$0.045
	5	Rhode Island	$0.063	$0.058	$0.049	$0.043
	6	Vermont	$0.064	$0.059	$0.050	$0.043
AESC 2015	1	Connecticut	$0.082	$0.076	$0.077	$0.062
	2	Massachusetts	$0.081	$0.076	$0.077	$0.062
	3	Maine	$0.070	$0.064	$0.065	$0.051
	4	New Hampshire	$0.080	$0.075	$0.075	$0.061
	5	Rhode Island	$0.077	$0.071	$0.071	$0.057
	6	Vermont	$0.070	$0.065	$0.066	$0.051
Delta	1	Connecticut	-$0.017	-$0.016	-$0.026	-$0.018
	2	Massachusetts	-$0.017	-$0.016	-$0.026	-$0.018
	3	Maine	-$0.011	-$0.009	-$0.019	-$0.012
	4	New Hampshire	-$0.015	-$0.014	-$0.023	-$0.016
	5	Rhode Island	-$0.014	-$0.013	-$0.022	-$0.014
	6	Vermont	-$0.007	-$0.006	-$0.017	-$0.009
Percent Difference	1	Connecticut	-21%	-21%	-34%	-29%
	2	Massachusetts	-21%	-21%	-34%	-30%
	3	Maine	-16%	-14%	-29%	-23%
	4	New Hampshire	-18%	-19%	-31%	-26%
	5	Rhode Island	-18%	-18%	-31%	-25%
	6	Vermont	-9%	-9%	-25%	-17%

Notes: These costs are the sum of wholesale energy costs and wholesale renewable energy certificate (REC) costs, increased by a wholesale risk premium of 8 percent (9 percent in AESC 2015), except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2018 $ per kWh. Levelization periods are 2016–2030 for AESC 2015 and 2018–2032 for AESC 2018. The real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018. Source: AESC 2015 Exhibit 1-6.

Modeling of energy prices by state

In the EnCompass model, Synapse developed energy prices for each hour of the year from 2018 to 2035 for each state and reporting region.[112] When these prices are rolled up to the traditional AESC periods (on-peak and off-peak, summer and winter), prices between regions do not substantially differ for any given year. Avoided energy costs for each reporting region are detailed in *Appendix B. Detailed Electric Outputs.*

[112] See Table 22 for a list of reporting regions.

6.2. Benchmarking the EnCompass Energy Model

The 2018 AESC Study Group required a calibration of the dispatch model used (i.e., EnCompass) with actual, historical data. To complete this, the Analysis Team developed modeling inputs that reflect our best understanding of electric system market operations in 2016. This included assumptions relating to available generating units, fuel prices, and system demand.

Figure 28 compares actual day-ahead LMPs for each New England region reported on by ISO New England against the same prices modeled in EnCompass for a 2016 data year.[113] This figure also details the percent difference between actual and modeled LMPs for each region. For the WCMA region, for example, average modeled LMPs for 2016 are 4 percent higher than actual historical LMPs. For all regions, modeled 2016 LMPs range from 2 percent lower to 4 percent higher than actual 2016 LMPs.

Figure 29 compares the monthly modeled LMPs for 2016 in the WCMA region against actual 2016 LMPs for the same region, and Figure 30 compares hourly modeled New England-wide average LMPs for 2016 against actual hourly 2016 LMPs for New England.[114] Our calibration for 2016 produces differences between modeled results and actual historical prices in line with the differences observed between a calibrated 2013 year in the 2015 AESC study. The scale of these differences indicates that the EnCompass model is accurately capturing the magnitude and differential spread of LMPs around New England during 2016. As in previous AESC studies, differences between price on a regional or temporal basis—for both the annual, monthly, and hourly calibrations—are likely related to differences between actual anomalies in the electric system (which are challenging to represent in an electric system dispatch model) and EnCompass' best-estimate rendering of a historical year. These "anomalies" may include actual and assumed generator and transmission outages (for which hourly data is unavailable or difficult to access), maintenance schedules (which are plant-specific and typically unknown), and operator discretion (which is often masked by ISO New England for confidentiality purposes).

[113] Actual LMP data available from the ISO New England website at https://www.iso-ne.com/static-assets/documents/2016/02/smd_hourly.xls.

[114] Note that the prices modeled in EnCompass most closely approximate day-ahead, rather than real-time prices. The day-ahead market is where most of the generating fleet is committed and compensated, whereas the real-time market mostly represents transfer payments for over-performance and under-performance; they do not necessarily approximate the price implied by the hour-by-hour demand.

Figure 28. Comparison of 2016 historical and simulated 2016 locational marginal prices

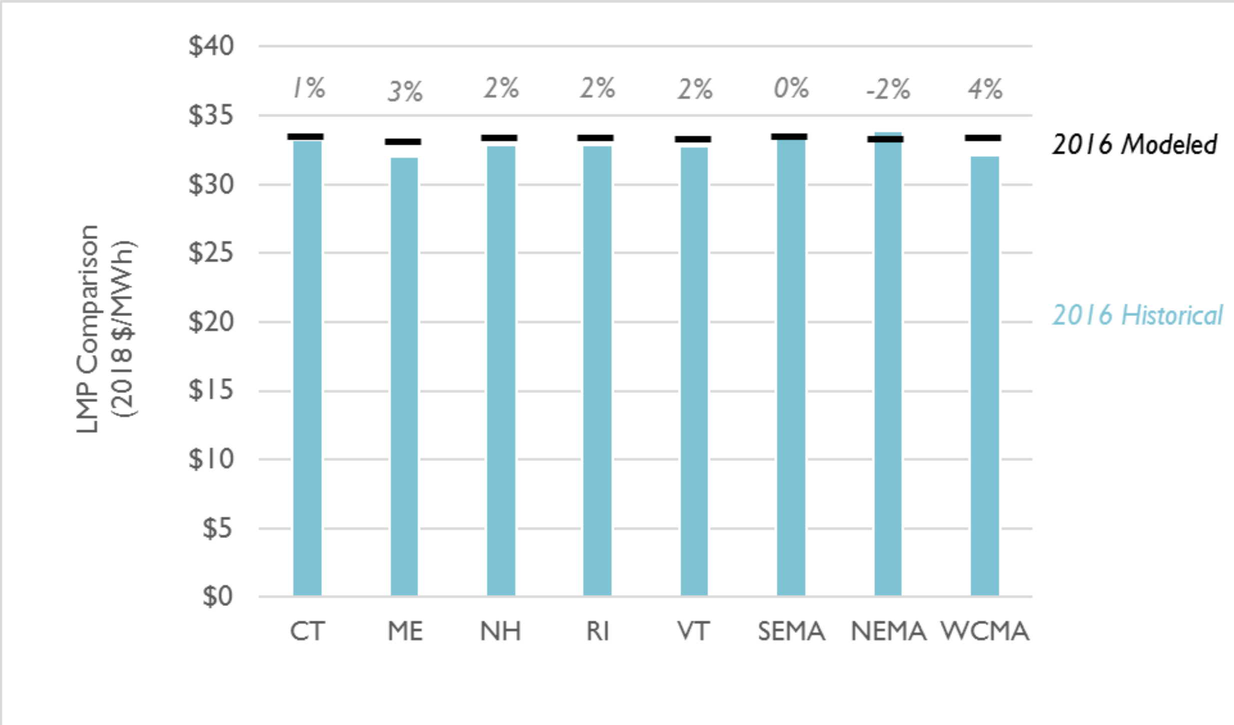


Figure 29. Comparison of 2016 historical and simulated 2016 locational marginal prices for the WCMA region (monthly)

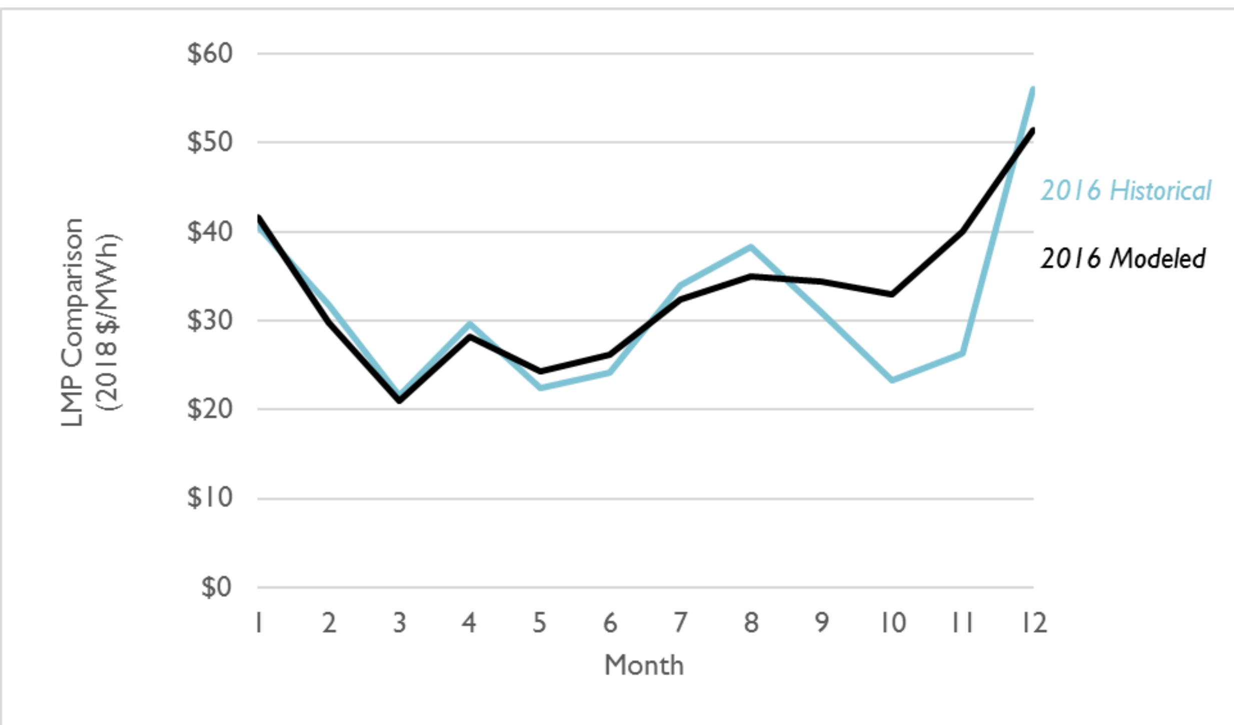
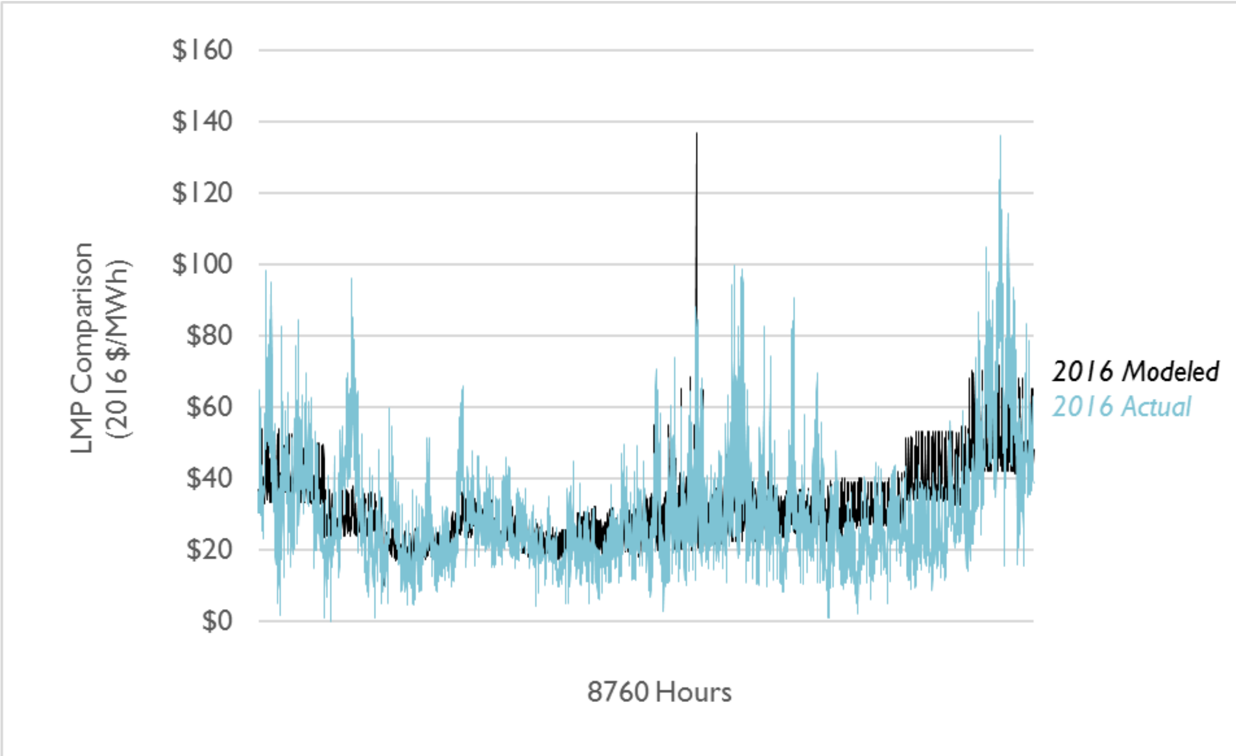


Figure 30. Comparison of 2016 historical and simulated 2016 locational marginal prices for New England (hourly)



7. AVOIDED COST OF COMPLIANCE WITH RENEWABLE PORTFOLIO STANDARDS AND RELATED CLEAN ENERGY POLICIES

Energy efficiency programs reduce the cost of compliance with RPS requirements by reducing total LSE load. Reduction in load due to energy efficiency or other demand-side resources will therefore reduce the RPS obligations of LSEs and the associated compliance costs recovered from consumers. This estimate of avoided costs includes the expected impact of avoiding each Class or Tier[115] of RPS[116] or Renewable Energy Standards[117] (RES) within each of the six New England states.

Table 46. Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$2.82	$0.21	$1.72	$1.51	$2.39	$0.53
MA CES	NA	NA	$0.45	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.44	$3.43	$0.03	$1.46
Total	**$3.76**	**$0.51**	**$3.61**	**$4.94**	**$2.42**	**$1.99**

Note that the avoided cost of RPS compliance is not equal to the REC price (detailed later in this chapter). Instead, the avoided cost is a function of REC price and load obligation percentage (i.e., the RPS target percentage). Therefore, the state with the highest or lowest REC price does not necessarily have the highest or lowest compliance cost because of the multiplicative impact of the RPS target.

Table 46 shows (with the exception of Maine and Vermont) levelized avoided costs significantly below those from AESC 2015. This reduction is attributable primarily to lower Class I REC premiums, driven by market surplus throughout most of the study period. In the near term, a supply boom stimulated mainly by distributed generation policies has surpassed demand, creating a market surplus. This surplus is sustained in the long term as substantial supply driven by large-scale renewable procurement policies in Connecticut, Massachusetts, and Rhode Island are expected to become operational without matching growth on the demand side.

[115] Vermont uses the term "tier" while all other New England states use the term "class" to describe RPS categories.

[116] Massachusetts, Connecticut, Maine, and New Hampshire use the term Renewable Portfolio Standard (RPS).

[117] Rhode Island and Vermont use the term Renewable Energy Standard (RES).

Table 47. AESC 2015 avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.48	$0.43	$7.05	$5.14	$5.43	$0
MA CES	NA	NA	NA	NA	NA	NA
All Other Classes	$1.13	$0.10	$2.19	$3.96	$0.02	$0
Total	**$8.62**	**$0.53**	**$9.25**	**$9.10**	**$5.44**	**$0**

7.1. Avoided Cost of Compliance with RPS Methodology

All six New England states now have active RPS or RES policies. [118,119] Each RPS program has multiple classes—referred to in Vermont as tiers—which are used to differentiate incentives by energy technology, vintage, emissions, and other criteria, based on state-specific policy objectives. Regional Class I requirements (as well as Class II in New Hampshire and Tier II in Vermont) are intended to create demand for new renewable energy additions. As a result, the RPS targets for these classes increase each year until a specified maximum obligation is reached. Massachusetts Class I is the notable exception to this rule. The Massachusetts Class I target currently increases 1 percent per year indefinitely. Class II (with the exception of NH), Class III, Class IV, and other "existing" supply obligations generally focus on generators that were already in operation prior to the adoption of RPS programs. This portion of the policy is intended to maintain the current fleet rather than spur the development of new generating facilities. As a result, the RPS targets for these classes do not generally increase each year, although some are subject to policymaker adjustment or discretion.

In 2017, Massachusetts adopted a Clean Energy Standard (CES). The CES obligates LSEs to provide a minimum percentage (exceeding the Massachusetts RPS Class I percentage) of load from clean energy resources. The CES target currently increases at 2 percent per year, which is inclusive of the Massachusetts Class I increase of 1 percent per year. CES-eligible resources include:

- Any projects certified under the Class I Massachusetts RPS; *or*
- Projects that are not Massachusetts Class I RPS eligible but have 20-yr lifetime net GHG impacts equal to 50 percent of a new natural gas combined cycle facility (these may include large hydro, biomass, new nuclear, and fossil with carbon capture); *and*
    - where the project has a Commercial Operation Date (COD) after Dec. 31, 2010; *and*
    - where the project is located in ISO New England or adjacent control area; or non-adjacent areas with a dedicated transmission line.

[118] Connecticut, Maine, Massachusetts, and New Hampshire

[119] Rhode Island and Vermont

Given the eligibility interaction between the Massachusetts CES and Massachusetts Class I RPS markets, REC and CEC price forecasts are modeled interdependently. RECs and Alternative Compliance Payments (ACP) used for Massachusetts Class I compliance will be counted toward CES compliance. Incremental CES demand above the Massachusetts Class I RPS is satisfied first by non-RPS eligible large hydro resources delivered over new transmission lines (if available), and second—if applicable—by a combination of Class I resources and Massachusetts CES ACPs, depending on regional Class I supply availability.

In addition to distinguishing between new and existing supply obligations, some New England RPS programs also include specified sub-component requirements for solar, biomass, hydroelectric, combined heat and power, waste-to-energy, thermal resources, energy transformation, or energy efficiency. For simplicity, this discussion refers to these obligations collectively as "RPS and CES requirements," even though some classes include resources that are not renewable. Each RPS obligation is described below and is subject to avoided cost analysis as part of AESC 2018.

The estimates of avoided RPS compliance cost include the expected impact of avoiding each Class or Tier of RPS or RES within each of the six New England states. The annual quantity of renewable energy that LSEs need to acquire to comply with RPS requirements is directly proportional to the annual load that the LSEs supply.

To the extent that the price of renewable energy exceeds the market price of electric energy, LSEs incur a cost to meet the RPS percentage target. That incremental unit cost is the price of a REC. The LSE's annual compliance cost equals the quantity of RECs (in MWhs) purchased by the LSE multiplied by the price paid per REC ($/MWh).

The RPS compliance cost that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices, multiplied by the percentage of retail load that a supplier must meet from renewable energy under the RPS regulations. RPS targets in all states are expressed as a percentage of retail load. For Massachusetts, Rhode Island, Maine, New Hampshire, and Vermont, the targets applied in this analysis reflect those in effect as of January 2018. For Connecticut, the draft Comprehensive Energy Strategy target of 30 percent by 2030 was assumed to be adopted.[120]

The key input to calculating the avoided cost of RPS compliance is REC price. REC prices are forecast using Sustainable Energy Advantage's REMO and Solar Market Study (SMS) models, and they include the impact of supply, demand, banking,[121] eligibility interactions across states and classes, the cost of new renewable entry, and the discretional operation and delivery of biomass and imports, respectively. For

[120] See http://www.ct.gov/deep/lib/deep/energy/ces/2017_draft_comprehensiveenergystrategy.pdf for more information.

[121] In the event that an LSE purchases RECs in excess of its current year RPS obligation, each state allows LSEs to save and count that quantity of compliance against either of the following two compliance years. This compliance flexibility mechanism is referred to as banking. LSEs may only bank compliance within a single state, and they may not transfer banked compliance credit to other entities.

all RPS classes focused on "existing" renewable energy facilities,[122] we forecasted REC prices based on a combination of expected supply and demand balance, relationships to and interactions with other RPS classes, and the ACP as an upper bound on REC price.

New additions to RPS supply

New renewable resources are those that qualify as "Class I" in Connecticut, Maine, Massachusetts, New Hampshire, and Maine, as "New" in Rhode Island, and as "Tier 2" in Vermont. New resources may also be required to satisfy the Massachusetts Alternative Energy Portfolio Standard (APS) and CES, the New Hampshire Class 1 thermal carve-out, the New Hampshire Class II solar, and Vermont Tier III. In contrast to these percentage target-based categories, the Massachusetts Class 1 solar carve-out represents the obligation to deliver a fixed quantity (MWh) of Solar RECs (SRECs) each year. Therefore, while obligation quantities may be adjusted year-to-year, the total SREC obligation over the full analysis period is not avoidable by reducing retail load, through energy efficiency measures or otherwise. Therefore, it was not treated as avoidable in this analysis. Table 48 summarizes the eligibility criteria for these categories and Table 49 summarizes the compliance obligation targets.

Table 48. Summary overview of eligibility for new RPS categories

State	RPS Class or Tier	COD Threshold[123]	Eligibility Notes
Connecticut	Class I	No threshold[124]	Subject to emissions threshold
Maine	Class I	After 9/1/2005	Allows refurbished facilities
Massachusetts	Class I	After 1/1/1998	Includes two solar carve-outs
	APS	After 1/1/2008	CHP and Useful Thermal Energy
New Hampshire	Class I	After 1/1/2006	Includes a thermal carve-out
	Class II	After 1/1/2006	Solar only
Rhode Island	New	After 1/1/1998	Fuel standard requirements apply
Vermont	Tier II	After 1/1/2015	Must be in-state and < 5 MW
	Tier III	After 1/1/2015	Class II resources also eligible

[122] "Existing" renewable energy facilities have a commercial operation date on or before 12/31/1997.

[123] The date after which a project must have commenced commercial operation in order to be eligible.

[124] An exception is that run-of-river hydro facilities must have commercial operation date on or after July 1, 2003.

Table 49. Summary of modeled[125] RPS targets for new resource categories, 2018 to 2032

	CT-I	ME-I	MA-I[1]	MA CES	MA APS	NH-I[2]	NH-I Thermal	NH-II	RI-New	VT-II	VT-III
2018	17%	10%	13%	3.0%	4.5%	8.7%	1.2%	0.5%	11.0%	1.6%	2.67%
2019	19.5%	10%	14%	4.0%	4.75%	9.6%	1.4%	0.6%	12.5%	2.2%	3.33%
2020	20%	10%	15%	5.0%	5.00%	10.5%	1.6%	0.7%	14.0%	2.8%	4.00%
2021	21%	10%	16%	6.0%	5.25%	11.4%	1.8%	0.7%	15.5%	3.4%	4.67%
2022	22%	10%	17%	7.0%	5.50%	12.3%	2.0%	0.7%	17.0%	4.0%	5.33%
2023	23%	NA	18%	8.0%	5.75%	13.2%	2.2%	0.7%	18.5%	4.6%	6.00%
2024	24%	NA	19%	9.0%	6.00%	14.1%	2.2%	0.7%	20.0%	5.2%	6.67%
2025	25%	NA	20%	10.0%	6.25%	15%	2.2%	0.7%	21.5%	5.8%	7.33%
2026	26%	NA	21%	11.0%	6.50%	15%	2.2%	0.7%	23.0%	6.4%	8.00%
2027	27%	NA	22%	12.0%	6.75%	15%	2.2%	0.7%	24.5%	7.0%	8.67%
2028	28%	NA	23%	13.0%	7.00%	15%	2.2%	0.7%	26.0%	7.6%	9.33%
2029	29%	NA	24%	14.0%	7.25%	15%	2.2%	0.7%	27.5%	8.2%	10.0%
2030	30%	NA	25%	15.0%	7.50%	15%	2.2%	0.7%	29.0%	8.8%	10.67%
2031	30%	NA	26%	16.0%	7.75%	15%	2.2%	0.7%	30.5%	9.4%	11.33%
2032	30%	NA	27%	17.0%	8.00%	15%	2.2%	0.7%	32.0%	10%	12.0%

Notes: (1) This is the gross MA-I target. The avoidable MA-I target is calculated based on a forward-looking estimate of solar carve-out obligations. (2) This is the gross NH-I target. The NH-I Thermal target is carved out of the NH-I target.

New renewable energy supply is derived from the pipeline of already committed (but not yet built) renewable energy supply, long-term contracting procurement policies, distributed generation policies, and additional supply above and beyond all policy-driven supply.

Table 50 summarizes the cumulative incremental new renewable energy resources, by fuel type, expected to be built in response to renewable energy policy—including procurement policy and incremental RPS demand.

[125] RPS target assumptions are based on current law except for Connecticut's, which are based on the proposed CES.

Table 50. Cumulative incremental *new* renewable energy resources, by fuel type (GWh)

	New England Supply						Imported Supply			
	Onshore Wind	Offshore Wind	Solar	Biomass	Small Hydro	NGFC	Wind	Solar	CES Hydro	Total
2018	56	0	1,670	28	0	244	118	0	0	**2,116**
2019	1,843	3	2,383	168	50	431	370	14	0	**5,262**
2020	2,320	15	3,279	205	57	648	389	29	0	**6,943**
2021	2,976	26	4,186	250	65	884	581	32	0	**9,000**
2022	3,269	375	4,826	310	71	954	646	32	4,150	**14,633**
2023	3,356	1,553	5,411	327	74	942	646	32	8,300	**20,641**
2024	3,359	2,638	5,788	358	138	931	646	32	8,300	**22,189**
2025	3,430	3,448	6,069	381	144	919	646	32	8,300	**23,368**
2026	3,569	4,257	6,253	404	205	908	646	32	8,300	**24,574**
2027	4,245	4,993	6,421	428	205	898	646	32	8,300	**26,166**
2028	4,555	5,729	6,521	428	205	887	646	32	8,300	**27,303**
2029	4,867	6,464	6,607	428	205	846	646	32	8,300	**28,395**
2030	5,180	7,016	6,640	428	205	789	646	32	8,300	**29,235**
2031	6,595	7,016	6,541	428	205	748	646	32	8,300	**30,512**
2032	6,695	7,016	6,462	428	205	724	646	32	8,300	**30,508**

Table 49 and Table 50 demonstrate that renewable energy supply-side and demand-side policies have come somewhat out of alignment. Specifically, both long-term wholesale procurement policies and DG contracting policies have been created and expanded in recent years, but demand target trajectories have not been modified to keep pace. This explains why renewable energy supply additions continue to grow in Table 50, while demand target increases cease in many markets.

RPS and CES compliance assumptions

AESC 2018 assumed that each LSE complies with RPS and CES obligations, by class and by state, in each calendar year—either by securing certified RECs or by making ACPs to the applicable regulatory authority. RPS requirements were derived by multiplying obligated load (which most often excludes municipal utilities), adjusted for contract exemptions, by the applicable annual class-specific RPS percentage target. We adjusted the forecast of obligated load to account for both current and expected behind-the-meter generation. In all states, RPS targets were defined as a percentage of obligated load. We assumed that Connecticut's CES is approved as proposed, including a 1 percent increase in the RPS through 2030. We further assumed that the Maine RPS ceases after 2022, in accordance with 2017 legislation.

Forecasting REC prices for compliance with Class I RPS obligations

Near-term supply/demand, REC prices, and renewable energy additions

The near-term Class I REC price forecast (from 2018 to approximately 2025) is based on an assessment of the near-term supply and demand balance, ACP levels in each market, banking limits and observed practices, operating import behavior, and discretional curtailment of operating biomass.

Resources considered in the estimation of near-term Class I REC supply and pricing are those eligible for any of the *New* resource categories. These resources may fall into one of the following categories:

- Certified supply, operating and located in ISO New England;
- Certified supply, operating and imported from adjacent control areas;
- Additional potential imports over existing ties to neighboring control areas; and
- Near-term committed renewable resources that (i) are in the interconnection queue; (ii) have been RPS-certified in one or multiple New England states; (iii) have secured financing; or (iv) have obtained long-term contracts, either with distribution utilities through competitive solicitations, or through other means.

For near-term committed resources that are not yet operational, this analysis applied a customized probability-derating to reflect the likelihood that not all proposed projects will be built, and may not be built on the timetable reflected in the queue or otherwise proposed by the project sponsors.

In addition to the resources described above, we forecasted the generation from renewable resources that are expected to come online as a result of existing state policies, including but not limited to:

- Massachusetts Section 83C Offshore Wind Procurement: ramping from 200 MW installed in Q4 2022 to 1600 MW by 2030.
- Massachusetts Section 83D Clean Energy Procurement: Procurement of approximately 9.45 TWh per year from a portfolio of selected bids that is import-dominated and represents a blend of Class I eligible resources and CES-eligible hydroelectric generation, as follows and as described in Table 51:
    - Class I renewables: ramping from 15 MW in 2019 to 420 MW by 2022
    - CES eligible hydro (not Class-I eligible): ramping from 100 MW in 2021 to 1,000 MW by 2023
- Solar Massachusetts Renewable Target (SMART) Program: 1600 MW no later than 2025
- Additional procurement under existing authority pursuant to Connecticut Public Act 13-303 and Public Act 15-107. Connecticut procurements are assumed separate from the Massachusetts 83D process.
    - Connecticut has released an RFP under Section 8 of PA 13-303. This RFP allows for the procurement of up to 889,250 MWh per year, and it is geared toward offshore wind (capped at 825,000 MWh per year), fuel cells, and anaerobic digesters. We assume the RFP results in 200 MW of offshore wind, and 20 average MW from fuel cells and/or anaerobic digesters.

- The new Section 8 procurement is modeled to count toward Connecticut's assumed additional procurement of 1 percent of load per year. Because offshore wind is expected to come online in large blocks, the result of this interaction is that there is no "additional CT procurement" in some years.

- Additional procurements under existing authority in Rhode Island, with replacement of the terminated Bowers Wind contract assumed to occur through the Clean Energy RFP, and authority originally applied to Clean Energy RFP rolled forward into an assumed future procurement. Offshore wind procurement is also assumed. Rhode Island procurements are assumed separate from the Massachusetts 83D process: 80 MW of land-based renewables (25 percent wind, 75 percent solar) and 100 MW of offshore wind

- Connecticut Low Emissions Renewable Energy Certificate (LREC) and Zero Emissions Renewable Energy Certificate (ZREC) Program: Includes a 7th program year

- Connecticut Fuel Cell Procurement Program: 30 MW by 2021

- Connecticut Solar Home Renewable Energy Certificate (SHREC) Program: 300 MW by 2023

- Rhode Island Renewable Energy Growth Program: 160 MW of contracts by 2019, followed by 35 MW of contracts per year (net of contract attrition) through 2029.

- Rhode Island Net Metering: 100 MW in service by 2022 under virtual net metering

- Vermont Standard Offer Program: 127.5 MW by 2021

- Vermont Net Metering: ~57 MW in service by 2019

Table 51. Assumed capacity and generation under Massachusetts Section 83D clean energy procurement

		2019	2020	2021	2022	2023 and later years
Class I Renewables	Capacity (MW)	15	120	350	420	420
Class I Renewables	Generation (GWh)	48	376	984	1,169	1,169
CES-Eligible Hydro Imports	Capacity (MW)	-	-	100	500	1,000
CES-Eligible Hydro Imports	Generation (GWh)	0	0	830	4,150	8,300
Total 83D	Capacity (MW)	15	120	450	9200	1,420
Total 83D	Generation (GWh)	48	376	1,814	5,319	9,469

Forecasted Class I REC supply was allocated proportionally among the states based on an algorithm that accounts for each state's RPS eligibility requirement, banking limits, relative ACP levels, and the expected discretional behavior of operating imports and biomass plants. Each state's resulting supply-demand balance, banking balances, ACPs, and forward-looking market dynamics were used to inform the forecast of near-term Class I REC prices.

Sustainable Energy Advantage forecasted SREC prices using a separate set of proprietary models, developed for its Massachusetts Solar Market Study. Its models were also updated to take into account the December 2017 tax reform and January 2018 solar trade tariff decision, as follows:

- **Tax reform:** The Tax Cuts and Jobs Act of 2017 (i) reduces the corporate tax rate from 35 percent to 21 percent, (ii) enables 100 percent expensing (bonus depreciation), (iii) reduces loan interest deductions, (iv) establishes a Base Erosion and Anti-Abuse Tax (BEAT), and (v) reduces state income tax deductibility from federal income taxes. The modeling takes into account the reduced corporate tax rates and the limitations on state income tax deductibility. Based on current deal terms and tax equity practices, we assumed that the additional bonus depreciation, interest deduction limits, and BEAT avoidance limits will not impact the majority of renewable energy finance transactions.
- **Solar trade tariffs:** Recent press regarding the recommended and expected solar trade tariffs has caused us to increase (modestly) the expected adverse impact on solar projects currently under development—and in particular, those projects that have entered long-term contracts through competitive bidding and now face the challenge of project financing with the prospect of higher than expected tariffs and the impact of tax reform.

Long-term cost of entry, REC prices and renewable energy additions

The long-term Class I REC price forecast (from approximately 2025–2035) is based on the cost of new entry of the marginal renewable energy unit required to meet the incremental RPS demand in each state in each year. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential that sorts the resources from the lowest cost of entry to the highest cost of entry. The resources in the supply curve model are represented by 1150 blocks of supply potential from resource studies, each with total MW capacity, capacity factor, and cost of installation and operation applicable to projects installed in each year. This supply curve is based on several proprietary resource potential studies. We derived the cost components of the supply curve analysis from a combination of public (e.g., the National Renewable Energy Laboratory Annual Technology Baseline) and confidential sources (e.g., research interviews with dozens of New England renewable energy developers).

The supply curve consists of land-based wind, offshore wind, utility-scale solar PV, biomass, hydro, landfill gas, and tidal resources.[126] While offshore wind is the largest potential resource by MW, land-

[126] The supply curve includes only the Class I eligible resource potential for each resource type.

based wind is the largest source by number of blocks (modeled as 1013 separate individual land-based wind sites), varying by state, land area, number and size of turbines in each project, wind speed, topography, and distance from transmission.

Resources from the supply curve were modeled to meet net demand, which consists of the gross demand for new or incremental renewables, less the near-term renewable supply (as described above).

The estimated 20-year levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure,[127] debt terms, required minimum equity returns, and depreciation, which are combined and represented through a carrying charge. The estimated levelized cost of marginal resources also includes fixed and variable operations and maintenance costs, generator-lead interconnection costs,[128] transmission network upgrade costs,[129] and wind integration costs. Phaseout of the Federal Production Tax Credit and phase-down of the Investment Tax Credit are modeled as adopted in the *Consolidated Appropriations Act of 2016*.

Revenues for land-based wind, offshore wind, and utility-scale solar resources are adjusted in two ways:

1. The value of energy is adjusted to reflect these resources' variability, production profile, and, for land-based wind, historical discount of the real-time market (in which wind plants will likely sell a significant portion of their output) versus the day-ahead market.
2. Land-based wind, offshore wind, and utility-scale solar PV generators are assumed to receive FCM revenues corresponding to only a percentage of nameplate capacity (~25 percent for land-based wind, 45 percent for offshore wind, and 12 percent for utility-scale solar PV), reflecting the seasonal reliability of the intermittent resources, as determined by ISO New England.

The REC cost for each block of the supply curve is estimated for each year. For each generator, we determine the levelized REC premium, or additional revenue the project would require in order to attract financing, for market entry by subtracting the nominal levelized value of production consistent with the AESC 2018 projection of wholesale electric energy and capacity prices from the nominal levelized cost of marginal resources:[130, 131]

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[127] For this analysis, we assumed incremental new supply will be financed with a blend of fully bundled power purchase agreements for a 20-year term and partial hedging for durations available in the short-term for their RECs, energy, and capacity.

[128] As a function of voltage and distance from transmission.

[129] It is assumed that 33–50 percent of the transmission costs are socialized and thereby not borne by the generators.

[130] We calculated these levelized analyses using discount rates representative of the cost of capital to a developer of renewable resource projects.

[131] NEPOOL is conducting an "Integrating Markets and Public Policy (IMAPP)" process that could change how clean energy and renewable energy resources participate in the wholesale market. Under the process, ISO New England has proposed to implement a "Competitive Auctions with Sponsored Policy Resources (CASPR)" policy that would create a two-stage

- The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis;
- The nominal levelized value of production is the amount the project would receive from selling energy and capacity into the wholesale market; and
- The difference between the levelized cost and the levelized value represents the REC premium.

Unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from lowest to highest REC premium price, and the intersection between incremental supply and incremental demand determines the market-clearing REC price for market entry. Our projections assume that REC prices for new renewables will not fall below $2 per MWh, which is the estimated transaction cost associated with selling renewable resources into the wholesale energy market. This estimate is consistent with market floor prices observed in various markets for renewable resources.

We expect resource levelized cost to undergo a number of changes throughout the analysis period. These changes include impacts resulting from capital cost decline, technological improvements (increasing capacity factors), need for transmission solutions, and the level of federal tax credits.

The levelized commodity revenue over the life of each resource was determined based on the sum of energy and capacity prices. REC price and avoided cost of RPS compliance were derived through an iterative approach. Draft REC prices were based on the preliminary energy and capacity forecasts. These REC prices were then used to generate final energy and capacity prices—which served as inputs for the final REC price and avoided RPS compliance cost calculation.

Forecasting REC prices for compliance with all other (Non-Class I) RPS obligations

As previously described, non-Class I markets are focused on maintaining existing resources—rather than spurring new development—and are therefore fundamentally different from Class I markets. As a result, the approach and assumptions for forecasting non-Class I REC prices were tailored to a different set of market characteristics. REC prices for non-Class I markets were forecasted as described in Table 52.

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capacity auction and allow "sponsored resources," including renewables and other certified resources that are receiving out-of-market revenue as a result of state or municipal policies, to substitute existing retiring resources. The proposed policy would also remove the existing "renewable technology resource (RTR)" exemptions. This analysis will model the impact of CASPR on the capacity revenues available to renewable resources. Other policy proposals currently being considered under the IMAPP process will not be included in this analysis.

Table 52. REC price forecasting approaches

RPS Market	REC Price Forecast Approach
CT Class II	Targets, ACPs, and eligibility have all recently been adjusted for the CT Class II RPS. REC prices were estimated based on current broker quotes, and were assumed to trend toward values which reflect a market in equilibrium or modest surplus over time, as existing eligible generators become certified and participate in the revised program.
CT Class III	REC prices were estimated based on current broker quotes and were assumed to trend toward the minimum nominal Class III REC price of $10/MWh.
ME Class II	REC prices were estimated based on current broker quotes, taking into account the impact of the VT Tier 1 RES.
MA Class II - Renewable	Near-term REC prices were estimated based on current broker quotes. Long term REC prices were forecast as the lesser of the CT Class I REC price and 50% of the MA-II-Renewable ACP.
MA Class II - WTE	REC prices were estimated based on current broker quotes.
MA APS	REC prices were estimated at 90% of the MA APS ACP.
NH Class II	REC prices were estimated at the lesser of 105% of the MA Class I REC price and 90% of the NH Class II ACP
NH Class III	Near-term REC prices were estimated based on current broker quotes. Long-term REC prices were forecast as the lesser of the CT Class I REC price and 98% of the NH-III ACP.
NH Class IV	Near-term REC prices were estimated based on current broker quotes. Long-term REC prices were forecast as the lesser of the CT Class I REC price and 50% of the MA Class II-Renewable ACP.
RI Existing	REC prices were estimated based on current broker quotes, taking into account the impact of the VT Tier 1 RES.
VT Tier I	REC prices were estimated based on current broker quotes, taking into account the impact of the VT Tier 1 RES.
VT Tier III	REC prices were estimated based on the lesser of the VT Tier II REC price and the NH Class I Thermal Carveout Price.

Alternative compliance payments

Table 53 provides a summary of ACP levels for each RPS category.

Table 53. Summary of alternative compliance payment levels

		2017 Alternative Compliance Payment (Nominal $/MWh)	Notes
CT	Class I	$55.00	Fixed and flat
	Class II	$25.00	Fixed and flat. Was $55; now $25 beginning 2018.
	Class III	$31.00	Fixed and flat. There is also a $10 floor price.
MA	Class I	$67.70	Adjusted by CPI each year.
	Solar Carveout I	$448.00	Schedule set by DOER.
	Solar Carveout II	$350.00	Schedule set by DOER.
	Class II – RE	$27.79	Adjusted by CPI each year.
	Class II – WTE	$11.12	Adjusted by CPI each year.
	APS	$22.23	Adjusted by CPI each year.
RI	New	$67.71	Adjusted by CPI each year.
	Existing	$67.71	Adjusted by CPI each year.
ME	Class I	$67.71	Adjusted by CPI each year.
	Class II	$67.71	Adjusted by CPI each year.
NH	Class I	$56.02	Adjusted by ½ of CPI each year.
	Class I - Thermal	$25.46	Adjusted by ½ of CPI each year.
	Class II	$56.02	Adjusted by ½ of CPI each year.
	Class III	$55.00	$55 through 2019.
	Class IV	$27.49	Adjusted by CPI each year.
VT	Tier I	$10.00	Adjusted by CPI each year.
	Tier II	$60.00	Adjusted by CPI each year.
	Tier III	$60.00	Adjusted by CPI each year.

Note: At the time of this writing, 2018 Alternative Compliance Payments have not yet been released.

Estimated REC premium for new renewable energy

Resources from the supply curve were modeled to meet net demand, which consists of the gross demand for new or incremental renewables, less existing eligible generation already operating. All imports, as well as New England-based biomass facilities, were modeled as discretional and responsive to expected REC prices through an iterative process. In addition, renewable supply expected to result from long-term procurement and distributed generation policies was modeled independently and netted from gross demand.

The projection of the cost of new entry (REC premium) is summarized in Table 54. Clean Energy Credit (CEC) prices for the Massachusetts CES were assumed to track MA-1 REC prices until CES-eligible hydro comes online (2022), then fall to $0 while hydro is marginal (the cost of hydro CECs cannot be avoided). A blended price was applied when hydro supply is present but not marginal. VT-III was modeled as the lesser of VT-II and a declining percentage of VT-III ACP with a floor of 50 percent of the ACP. REC prices were forecast to increase in the later years of the analysis period not only because the cost of new entry increases as resources further up the supply curve are deployed, but also because compliance bank balances are expected to be depleted by this time.

Table 54. REC premium for market entry (2018 $/MWh)

	CT-I	ME-I	MA-I	MA CES	MA APS	NH-I	NH-I Thermal	NH-II	RI-New	VT-II	VT-III
2018	$19.88	$18.75	$18.75	$18.75	$21.54	$18.75	$23.14	$21.57	$23.21	$18.75	$18.75
2019	$44.85	$1.96	$44.85	$44.85	$19.01	$44.85	$22.92	$50.42	$44.86	$44.85	$44.85
2020	$33.53	$1.92	$39.64	$39.64	$16.77	$34.80	$22.69	$45.58	$39.71	$39.64	$30.60
2021	$22.50	$1.88	$28.49	$21.46	$14.80	$23.75	$22.47	$32.77	$28.57	$28.49	$28.49
2022	$9.92	$1.85	$10.35	$0.00	$13.06	$10.19	$22.25	$11.91	$10.42	$10.35	$10.35
2023	$11.25	$0.00	$11.25	$0.00	$11.52	$11.25	$22.03	$12.93	$11.25	$11.25	$11.25
2024	$9.55	$0.00	$9.55	$0.00	$11.34	$9.55	$19.44	$10.98	$9.55	$9.55	$9.55
2025	$6.38	$0.00	$6.95	$0.00	$11.34	$6.46	$17.15	$7.99	$7.05	$6.95	$6.95
2026	$4.78	$0.00	$5.80	$0.00	$11.34	$4.81	$15.13	$6.67	$5.93	$5.80	$5.80
2027	$3.15	$0.00	$4.52	$0.00	$11.34	$3.05	$13.35	$5.20	$4.64	$4.52	$4.52
2028	$2.49	$0.00	$3.58	$0.00	$11.34	$2.23	$11.78	$4.11	$3.61	$3.58	$3.58
2029	$2.04	$0.00	$2.92	$0.10	$11.34	$1.81	$10.40	$3.36	$2.91	$2.92	$2.92
2030	$1.68	$0.00	$2.34	$0.26	$11.34	$1.58	$9.17	$2.69	$2.33	$2.34	$2.34
2031	$1.56	$0.00	$2.06	$0.36	$11.34	$1.55	$8.09	$2.37	$2.04	$2.06	$2.06
2032	$3.23	$0.00	$3.48	$0.81	$11.34	$3.23	$7.14	$4.00	$3.47	$3.48	$3.48
Levelized (2018-2032)	**$12.38**	**$1.91**	**$13.59**	**$9.02**	**$13.40**	**$12.45**	**$16.80**	**$15.54**	**$13.95**	**$13.59**	**$12.94**

The REC premium (REC Price) results are highly dependent upon the forecast of wholesale electric energy market prices. This includes the underlying forecasts of natural gas and carbon allowance prices, as well as the forecast of inflation. A lower forecast of market energy prices would yield higher REC prices than shown, particularly in the long term. In all cases, project developers will need to be able to secure long-term contracts and attract financing based on the aforementioned natural gas, carbon, and resulting electricity price forecasts in order to create this expected REC market environment. This presents an important caveat to the projected REC prices, as such long-term electricity price forecasts (particularly to the extent that they are influenced by expected carbon regulation) are uncertain.

In contrast to the long-term REC cost of entry, spot prices in the near term will be driven by supply and demand. But they are also influenced by REC market dynamics and to a lesser extent by the expected cost of entry (through banking), as follows:

- Market shortage: Prices approach the cap or Alternative Compliance Payment.
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $2/MWh, reflecting transaction and risk management costs.
- Market surplus with banking: Prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors.

Historical REC prices

We relied upon recent broker quotes to estimate the market prices at which RECs are transacted. REC markets in New England continue to suffer from a lack of depth, liquidity, and price visibility. Broker quotes for RECs represent the best visibility into the market's view of current spot prices. However, since RPS compliance must be substantiated annually, and actual REC transactions occur sporadically throughout the year, the actual weighted average annual price at which RECs are transacted will not necessarily correspond to the straight average of broker quotes over time. Broker quotes for RECs may span several months with few changes and no actual transactions (being represented by offers to buy or sell), and at other times may represent a significant volume of actual transactions. As a result, care should be taken to filter such data for reasonableness. This table was developed from a representative sampling of REC brokers quotes, which is comprised of both consummated transactions and bid-ask spreads in periods where transactions were not reported. For reference, Table 55 shows annual average historical REC prices for New RPS markets.

Table 55. Annual average historical REC prices, new supply: 2010–2016, plus 2017 Jan – Sep (nominal $ per MWh)

		2010	2011	2012	2013	2014	2015	2016	Jan–Sept 2017
CT	Class I	$14	$39	$54	$55	$52	$44	$22	$20
MA	Class I	$14	$44	$63	$64	$54	$44	$22	$20
	APS	NA	$19	$19	$20	$21	$21	$21	$22
RI	New	$15	$44	$62	$64	$52	$43	$23	$20
ME	Class I	$7	$25	$37	$9	$2	$18	$22	$14
NH	Class I	$14	$44	$61	$54	$53	$45	$24	$19
	Class II – Solar	$25	$48	$62	$53	$53	$51	$43	$34
VT	Tier II	NA	NA	NA	NA	NA	NA	NA	NA*
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA*

** Broker quotes were not yet available for VT markets at the time these data were collected.*

Eligibility and targets for existing RPS categories

While "New" RPS requirements are generally designed to spur the development of new renewable resources, classes focused on resources already in service are generally described as "maintenance tiers" and are designed to provide just enough financial incentive to keep the existing fleet of renewable resources in reliable operation. Table 56 summarized existing RPS categories and associated eligibility criteria.

Table 56. Summary overview of eligibility for existing RPS categories

State	RPS Class or Tier	COD Threshold[132]	Eligibility Notes
Connecticut	Class II	No threshold	Class I resources also eligible
	Class III	No threshold	Includes conservation and load management
Maine	Class II	Before 9/1/2005	Allows hydro up to 100 MW
Massachusetts	Class II	Before 1/1/1998	Includes same biomass standards as Class I
	Class II-WTE	Before 1/1/1998	Dedicated class for waste-to-energy
New Hampshire	Class III	Before 1/1/2006	Dedicated to biomass and LFG
	Class IV	Before 1/1/2006	Small hydro only
Rhode Island	Existing	Before 1/1/1998	Fuel standard requirements apply
Vermont	Tier I	No threshold	Class II and RE portion of imports also eligible

Due to their maintenance orientation, the percentage targets for "existing" classes are generally held constant, with annual obligations varying only based on changes in the load forecast. Vermont Tier-I is the notable exception, with targets increasing through 2035. While the commencement of the VT-I market has recently caused small increases in the price of RECs from existing facilities, additional substantive increases are not expected as VT-I continues to increase.

Table 57. Summary of RPS targets for existing resource categories, 2018–2032

	CT-II[133]	CT-III	ME-II	MA-II RE	MA-II WTE	NH-III	NH-IV	RI-Existing	VT-I[134]
2018	4%	4%	30%	2.6%	3.5%	8%	1.5%	2%	55%
2019	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	55%
2020	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	59%
2021	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	59%
2022	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	59%
2023	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	63%
2024	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	63%
2025	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	63%
2026	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	67%
2027	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	67%
2028	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	67%
2029	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	71%
2030	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	71%
2031	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	71%
2032	4%	4%	30%	3.6%*	3.5%	8%	1.5%	2%	75%

** Subject to annual adjustment by MA DOER.*

132 The date after which a project must have commenced commercial operation in order to be eligible.

133 Connecticut Class I supply can be counted toward compliance with Connecticut Class II requirements.

134 Vermont Tier II supply can be counted toward compliance with Vermont Tier I requirements.

Estimated REC premium for existing RPS categories

In contrast to the New RPS markets (where long-term REC prices are based on the cost of new entry), REC prices in Existing RPS markets are based on the relationship between supply and demand, interactions with other markets, and the ACP. The following summarizes the core determinants of REC prices in Existing RPS markets:

- CT-II: The REC forecast reflects recent target and eligibility adjustments. REC prices are based on current market prices for 2018 and are then trended to equilibrate with the MA-II WTE market over three years, on the assumption that the long-term dynamics of these two markets are similar.
- CT-III: REC prices for CT-III reflect a trend toward equilibrium, and a low probability that the market will again over-build to prior levels of surplus.
- ME-II, RI-Existing, MA-II-WTE, and VT-I REC prices reflect markets expected to remain in long-term equilibrium.
- MA-II REC prices were assumed to be the lesser of CT-I and 95 percent of the MA-II ACP.
- MA APS REC prices were modeled on a trajectory from 95 percent to 50 percent of ACP.
- NH-I Thermal was assumed to price at 90 percent of ACP until 2023, and then decline by 10 percent per year to a floor price of $2.
- NH-II was modeled as the lesser of 115 percent of MA-I and 90 percent of NH-II ACP, based on differential between NH-II and MA-I as of January 2018.
- NH-IV REC prices were assumed to be the lesser of CT-I and 90 percent of NH-IV ACP.
- VT-II REC prices were assumed as the lesser of MA-I and 100 percent of VT-II ACP (percent of ACP not discounted because VT-II supply has outlet in Massachusetts that can go above VT-II ACP).

Table 58. Summary of REC prices for existing resource categories, 2018–2032, 2018$/MWh

	CT-II[135]	CT-III	ME-II	MA-II RE	MA-II WTE	NH-III	NH-IV	RI-Existing	VT-I[136]
2018	$13.00	$25.00	$2.00	$19.88	$6.00	$38.63	$19.88	$1.75	$1.88
2019	$10.46	$23.28	$1.96	$26.93	$5.88	$44.85	$25.24	$1.72	$1.84
2020	$8.01	$21.63	$1.92	$26.93	$5.77	$20.84	$25.24	$1.68	$1.80
2021	$5.65	$20.02	$1.88	$22.50	$5.65	$10.07	$22.50	$1.65	$1.77
2022	$5.54	$18.48	$1.85	$9.92	$5.54	$11.98	$9.92	$1.62	$1.73
2023	$5.43	$16.98	$0.45	$11.25	$5.43	$11.25	$11.25	$1.59	$1.02
2024	$5.33	$15.54	$0.44	$9.55	$5.33	$9.55	$9.55	$1.55	$1.00
2025	$5.22	$14.15	$0.44	$6.38	$5.22	$6.38	$6.38	$1.52	$0.98
2026	$5.12	$12.80	$0.43	$4.78	$5.12	$4.78	$4.78	$1.49	$0.96
2027	$5.02	$11.51	$0.42	$3.15	$5.02	$3.15	$3.15	$1.46	$0.94
2028	$4.92	$10.25	$0.41	$2.49	$4.92	$3.98	$2.49	$1.44	$0.92
2029	$4.83	$10.05	$0.40	$2.04	$4.83	$5.69	$2.04	$1.41	$0.90
2030	$4.73	$9.86	$0.39	$1.68	$4.73	$8.28	$1.68	$1.38	$0.89
2031	$4.64	$9.66	$0.39	$1.56	$4.64	$10.72	$1.56	$1.35	$0.87
2032	$4.55	$9.47	$0.38	$3.23	$4.55	$13.87	$3.23	$1.33	$0.85
Levelized (2018–2032)	**$6.27**	**$15.54**	**$0.95**	**$10.62**	**$5.27**	**$14.06**	**$10.37**	**$1.54**	**$1.24**

For reference, Table 59 shows annual average historical REC prices for Existing RPS markets.

Table 59. Annual average historical REC prices, existing supply: 2010–2016, plus 2017 Jan–Sep (nominal $/MWh)

		2010	2011	2012	2013	2014	2015	2016	Jan–Sept 2017
CT	Class II	$0	$0	$0	$0	$1	$1	$1	$8
	Class III	$11	$10	$10	$11	$25	$27	$27	$26
MA	Class II – Renewable	$24	$24	$25	$26	$26	$27	$26	$27
	Class II – WTE	$3	$4	$7	$8	$8	$6	$6	$6
RI	Existing	$1	$1	$1	$1	$1	$1	$1	$1
ME	Class II	$0	$0	$0	$0	$0	$0	$1	$1
NH	Class III	$21	$26	$29	$29	$30	$37	$28	$35
	Class IV	$25	$28	$29	$25	$24	$25	$25	$25
VT	Tier I	NA	NA	NA	NA	NA	NA	NA	NA*

** Broker quotes were not yet available for VT markets at the time these data were collected.*

135 Connecticut Class I supply can be counted toward compliance with Class II requirements.

136 Vermont Tier II supply can be counted toward compliance with Tier I requirements.

7.2. Avoided RPS Compliance Cost Per MWh Reduction

The RPS compliance costs that retail customers avoid through reductions in their energy usage is equal to the price of renewable energy in excess of market prices multiplied by the percentage of retail load that a supplier must meet from renewable energy under the RPS regulation. In other words:

Equation 1. RPS compliance costs

$$\frac{\sum_{\mathrm{n}} \mathrm{P}_{\mathrm{n,i}} \times R_{n,i}}{1-l}$$

Where:
i = year
n = RPS classes
$P_{n,i}$ = projected price of RECs for RPS class n in year i,
$R_{n,i}$ = RPS requirement, expressed as a percentage, for RPS class n in year i,
l = losses from ISO wholesale load accounts to retail meters (modeled at 8%)

For example, in a year in which REC prices are $15/MWh and the RPS percentage target is 10 percent, the avoided RPS cost to a retail customer would be $15 × 10% = $1.50/MWh.

7.3. Results

Table 60 and Table 61 summarize the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs.[137] Note that the avoided cost of RPS compliance is not equal to the REC price; instead, the avoided cost is a function of REC price and load obligation percentage (i.e., the RPS target percentage). Therefore, the state with the highest or lowest REC price does not necessarily have the highest or lowest compliance cost because of the multiplicative impact of the RPS target.

[137] All levelized values use the long-term real rate as the discount factor.

Table 60. Summary of avoided cost of RPS compliance, new RPS categories, 2018–2032, 2018$/MWh

	CT-I	ME-I	MA-I	MA CES	MA APS	NH-I	NH-I Thermal	NH-II	RI-New	VT-II	VT-III
2018	$3.65	$2.03	$1.43	$0.61	$1.05	$1.76	$1.87	$0.12	$2.76	$0.32	$0.54
2019	$9.45	$0.21	$4.33	$1.94	$0.98	$4.65	$2.03	$0.33	$6.06	$1.07	$1.61
2020	$7.24	$0.21	$4.21	$2.14	$0.91	$3.95	$2.18	$0.34	$6.00	$1.20	$1.32
2021	$5.10	$0.20	$3.28	$1.39	$0.84	$2.92	$2.33	$0.25	$4.78	$1.05	$1.44
2022	$2.36	$0.20	$1.31	$0.00	$0.78	$1.35	$2.47	$0.09	$1.91	$0.45	$0.60
2023	$2.79	$0.00	$1.55	$0.00	$0.72	$1.60	$2.62	$0.10	$2.25	$0.56	$0.73
2024	$2.47	$0.00	$1.59	$0.00	$0.73	$1.45	$2.50	$0.08	$2.06	$0.54	$0.69
2025	$1.72	$0.00	$1.25	$0.00	$0.77	$1.05	$2.37	$0.06	$1.64	$0.44	$0.55
2026	$1.34	$0.00	$1.16	$0.00	$0.80	$0.78	$2.09	$0.05	$1.47	$0.40	$0.50
2027	$0.92	$0.00	$1.00	$0.00	$0.83	$0.49	$1.85	$0.04	$1.23	$0.34	$0.42
2028	$0.75	$0.00	$0.89	$0.00	$0.86	$0.36	$1.63	$0.03	$1.01	$0.29	$0.36
2029	$0.64	$0.00	$0.76	$0.02	$0.89	$0.29	$1.44	$0.03	$0.86	$0.26	$0.32
2030	$0.54	$0.00	$0.63	$0.04	$0.92	$0.26	$1.27	$0.02	$0.73	$0.22	$0.27
2031	$0.51	$0.00	$0.58	$0.06	$0.95	$0.25	$1.12	$0.02	$0.67	$0.21	$0.25
2032	$1.05	$0.00	$1.01	$0.15	$0.98	$0.52	$0.99	$0.03	$1.20	$0.38	$0.45
Levelized	**$2.82**	**$0.21**	**$1.72**	**$0.45**	**$0.86**	**$1.51**	**$1.94**	**$0.11**	**$2.39**	**$0.53**	**$0.69**

Table 61. Summary of avoided cost of RPS compliance, existing RPS categories, 2018–2032, 2018$/MWh

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	NH-III	NH-IV	RI-Existing	VT-I
2018	$0.56	$1.08	$0.65	$0.56	$0.23	$3.34	$0.32	$0.04	$1.08
2019	$0.45	$1.01	$0.64	$0.78	$0.22	$3.88	$0.41	$0.04	$1.05
2020	$0.35	$0.93	$0.62	$1.05	$0.22	$1.80	$0.41	$0.04	$1.09
2021	$0.24	$0.87	$0.61	$0.87	$0.21	$0.87	$0.36	$0.04	$1.06
2022	$0.24	$0.80	$0.60	$0.39	$0.21	$1.04	$0.16	$0.03	$1.03
2023	$0.23	$0.73	$0.15	$0.44	$0.21	$0.97	$0.18	$0.03	$0.64
2024	$0.23	$0.67	$0.14	$0.37	$0.20	$0.82	$0.15	$0.03	$0.62
2025	$0.23	$0.61	$0.14	$0.25	$0.20	$0.55	$0.10	$0.03	$0.61
2026	$0.22	$0.55	$0.14	$0.19	$0.19	$0.41	$0.08	$0.03	$0.63
2027	$0.22	$0.50	$0.14	$0.12	$0.19	$0.27	$0.05	$0.03	$0.61
2028	$0.21	$0.44	$0.13	$0.10	$0.19	$0.34	$0.04	$0.03	$0.59
2029	$0.21	$0.43	$0.13	$0.08	$0.18	$0.49	$0.03	$0.03	$0.61
2030	$0.20	$0.43	$0.13	$0.07	$0.18	$0.72	$0.03	$0.03	$0.60
2031	$0.20	$0.42	$0.13	$0.06	$0.18	$0.93	$0.03	$0.03	$0.58
2032	$0.20	$0.41	$0.12	$0.13	$0.17	$1.20	$0.05	$0.03	$0.60
Levelized	**$0.27**	**$0.67**	**$0.31**	**$0.38**	**$0.20**	**$1.21**	**$0.17**	**$0.03**	**$0.77**

Table 62 shows the avoided cost of RPS compliance aggregated for all Class 1/New categories and, separately, all other categories. The exception is the Massachusetts CES, which we show separately.

Table 62. Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$2.82	$0.21	$1.72	$1.51	$2.39	$0.53
MA CES	NA	NA	$0.45	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.44	$3.43	$0.03	$1.46
Total	**$3.76**	**$0.51**	**$3.61**	**$4.94**	**$2.42**	**$1.99**

Note: Each state has multiple Classes or Tiers. Rhode Island and Maine have two, Connecticut and Vermont have three, and Massachusetts and New Hampshire have four. For simplicity, we sum avoided costs for all non-Class I/New RPS policies together in the "all other classes" row.

8. NON-EMBEDDED ENVIRONMENTAL COSTS

Some environmental costs are embedded (economists would say "internalized") in energy prices through regulations that require expenditures to reduce emissions. Other environmental impacts, which also impose real damages on society, are not embedded in prices. For the 2018 AESC Study, we estimated values for some of the principal non-embedded environmental costs.[138] Here we address two such categories: the non-embedded portion of GHG impacts, and the costs of NO_X emissions.

2018 develops two approaches to the total environmental costs of GHG emissions. The first approach, based on global marginal abatement costs, establishes a total environmental cost of $100 per short ton of CO_2-eq emissions (identical to the prior AESC 2015 value), reflecting the fact that best available cost estimates for large-scale carbon capture and sequestration (CCS) have barely changed since 2005. The second approach, based on New England marginal abatement costs, establishes a total environmental cost of $174 per short ton of CO_2-eq emissions, based on a projection of future costs of offshore wind energy. Since this environmental cost can be best characterized as a global marginal abatement cost, we also calculate a New England-specific marginal abatement cost of $318 per short ton based on the current estimated cost of offshore wind. AESC 2018 establishes a non-embedded NO_X emission cost of $31,000 per ton of N, based on a review of findings in the literature, which translates into a wholesale avoided cost for NO_X of $1.58 per MWh.

Non-embedded costs are (by definition) not included in the modeling of avoided energy costs. This is in contrast to costs associated with RGGI, SO_2 regulation programs, and Massachusetts' 310 CMR 7.74 regulation, which are included within AESC 2018's modeling of energy prices and thus have an already quantified impact on the avoided energy costs (see Chapter 4 *Common Electric Assumptions* for a discussion of how these costs are modeled). Readers of AESC may also wish to add a non-embedded GHG cost to an avoided energy cost in a given year. In order to do this, readers must first subtract out the RGGI cost (in Connecticut, Maine, New Hampshire, Rhode Island, or Vermont) or both the RGGI cost and 310 CMR 7.74 cost (in Massachusetts only) from the GHG cost to determine the remaining cost that is non-embedded. Meanwhile, the non-embedded NO_X cost may be simply added to the energy cost, as we do not model an embedded NO_X cost in AESC 2018. See Appendix B and Appendix G for more detail on this topic.

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[138] The AESC non-embedded environmental cost represents a societal (international) value. For the purposes of state screening of energy efficiency investments, individual states or jurisdictions may consider adjusting the AESC non-embedded values based on the policies in place for renewable portfolio standards. The previous chapter describes the treatment of avoided RPS costs associated with energy efficiency measures.

8.1. Non-Embedded GHG Costs

Costs of GHG emissions are partially embedded in prices through RGGI allowances, state regulations such as the Massachusetts GWSA, and federal policies such as the previously proposed Clean Power Plan. However, the costs embedded by these policies represent only a portion of the total environmental impacts of GHG emissions. Therefore, we estimate the total cost of GHG emissions; the non-embedded portion is the difference between our total cost estimates and the smaller, embedded portion of GHG impacts.

There are two leading methods for estimating environmental costs: based on damage costs or based on marginal abatement costs. (In the idealized market of textbook economics, the two would coincide; in the real world, they are not necessarily identical.)

Damage costs, if available and reliable, would be preferable, since they are a direct measure of the environmental impacts in question. Unfortunately, there are serious uncertainties surrounding climate damage estimates, based on both the theoretical frameworks for extreme risks and discounting of future impacts, and on the intrinsic problems of forecasting impacts at temperatures outside the range of historical experience.

The social cost of carbon (SCC) estimates produced by the Obama administration's interagency task force in 2013 are a well-known example of damage cost estimates, averaging results from three climate economics models. All three models, however, minimize or ignore risks of extreme events, and rely on traditional, somewhat dated estimates of future damages. A review by the National Academy of Sciences (2017) found many problems in these models and called for development of a new approach to SCC estimates.[139] A meta-analysis of SCC estimates, focusing on the incorporation of extreme risk, found that the SCC should be at least $125 per metric ton of CO_2 (2014).[140]

In view of the many uncertainties in climate damage cost estimates, we conclude (as did AESC 2013 and 2015) that the marginal abatement cost method should be used instead. This method asserts that the value of damages avoided, at the margin, must be at least as great as the cost of the most expensive abatement technology used in a comprehensive strategy for emission reduction.

There are two interpretations of marginal abatement costs, leading to different cost estimates. On the one hand, GHGs are a global problem: because they are persistent and well-mixed in the atmosphere, emissions anywhere affect climate change everywhere. This suggests an international perspective, identifying the marginal abatement cost on a least-cost global scenario for emission reduction. On the other hand, New England states have set their own targets for GHG emission reduction and are

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139 National Academy of Sciences, Engineering and Medicine (2017), Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Available at https://www.nap.edu/download/24651#.

140 J.X.J.M. van den Bergh and W.J.W. Botzen (2014), "A lower bound to the social cost of CO_2 emissions," *Nature Climate Change* 4, 253-258, quote from p. 256.

developing local strategies for meeting those targets. This suggests a local perspective, identifying the marginal abatement cost on a local scenario for meeting local emission reduction targets.

We find, again echoing AESC 2013 and 2015, that CCS is the marginal abatement technology in many global scenarios for climate mitigation. Although CCS has been studied in small-scale experiments, it has not yet been demonstrated at the industrial scale needed for widespread emission reduction. That is, it seems barely farther along than it was at the time of AESC 2013 or 2015. The best available cost estimates for large-scale CCS have barely changed since 2005; for a new NGCC plant with geological storage, the central estimate from a 2015 review article is \$101 per metric ton of CO_2 (2013 dollars).[141] Converted into 2018 dollars per short ton, this yields a value of \$99 per short ton, which we round up to \$100 per short ton to avoid false precision. This is our international perspective estimate.[142]

From a local perspective, the marginal abatement technology for Massachusetts, and potentially for other states, is offshore wind. Scenarios for compliance with Massachusetts GHG reduction targets involve substantial investment in offshore wind. The industry is still in its infancy, at least in the United States, but cost information is beginning to emerge for offshore wind. In Maryland, the Public Service Commission (PSC) recently approved two offshore wind projects, coming online in 2020 and 2023, at \$140/MWh in 2016 dollars. This is similar to costs that have been informally suggested elsewhere. Massachusetts will announce the winning bids for the first tranche of offshore wind under 220 CMR 23 Section 83C on April 23, 2018.

As a marginal abatement technology in New England, offshore wind will displace gas-fired generation. Recent EIA data imply that gas power plants emit 0.46 short tons of CO_2 per MWh.[143] Thus offshore wind, at \$140/MWh, would be reducing emissions at a cost of \$140 / 0.46 = \$304 / short ton CO_2, or \$318 after conversion to 2018 dollars. It seems likely that costs will decline over time, as industry becomes more experienced with offshore wind development. This has been the case in Europe. Figure 31 shows recent offshore wind project prices based on commercial operation date.

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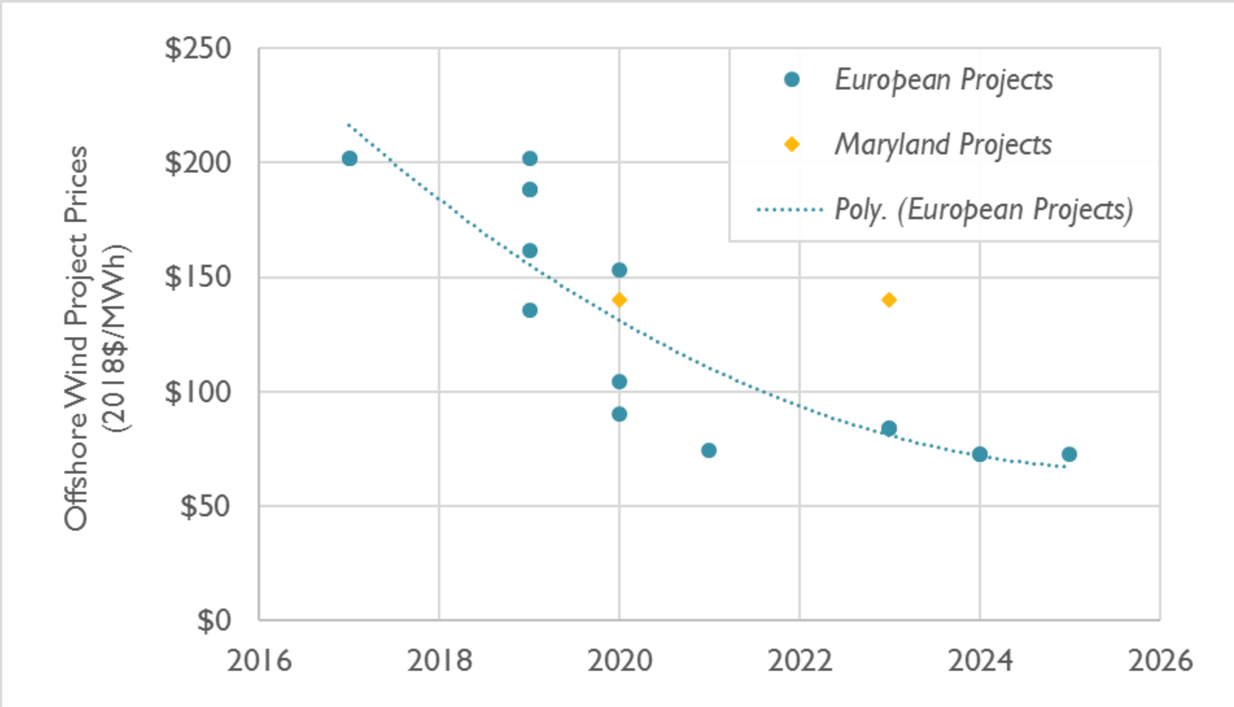
141 Edward S. Rubin, John E. Davison and Howard J. Herzog (2015), "The cost of CO2 capture and storage," International Journal of Greenhouse Gas Control, https://www.cmu.edu/epp/iecm/rubin/PDF%20files/2015/Rubin_et_al_ThecostofCCS_IJGGC_2015.pdf. The estimate cited here is the midpoint of the range in Table 16, line 1 (\$59 - \$143/metric ton in 2013 dollars).

142 Since this is a global abatement cost estimate, the recent increase in the U.S. tax credit for CCS applies to only a small fraction of the needed worldwide CCS investment and can safely be ignored.

143 U.S. EIA, "How much carbon dioxide is produced per kilowatt-hour when generating electricity with fossil fuels?" https://www.eia.gov/tools/faqs/faq.php?id=74&t=11. See Tables 8.1 and A.3.

Figure 31. Recent offshore wind project prices and commercial operation dates



Source: Data from NREL, "2016 Offshore Wind Technologies Report." Page 57. Available at https://www.energy.gov/eere/wind/downloads/2016-offshore-wind-technologies-market-report.

The figure shows the trajectory of European offshore wind prices and the two approved Maryland projects for comparison. Prices for future offshore wind projects in Denmark and the Netherlands, countries with much more experience with this technology, have recently fallen to €50 – 55 / MWh, i.e., less than half of the Maryland $140/MWh estimate.[144] We anticipate that offshore wind prices in the United States will follow a similar trajectory over the study period of 2018 to 2032. We anticipate that by 2028, offshore wind project prices will be about half of the current prices. On a 15-year levelized basis, we anticipate that offshore wind prices will be approximately $80/MWh. This translates to a cost per avoided ton of CO_2 of $174 per short ton. We also anticipate that this value will change with the expected announcements of new offshore wind projects along the eastern seaboard during the study period.

It is not surprising that the local marginal abatement cost is greater than the global cost. The least-cost scenario for meeting global targets need not be consistent with local scenarios for meeting similar-sounding local targets. Global emission reduction of, say, 80 percent by 2050 is not the same as reduction of Massachusetts or New England emissions by 80 percent by 2050. If, as seems believable, New England is a higher-than-average-cost location for emission reduction, then the least-cost global

[144] Arnout de Pee, Florian Küster and Andreas Schlosser (2017), "Winds of change? Why offshore wind might be the next big thing," McKinsey & Company, https://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/winds-of-change-why-offshore-wind-might-be-the-next-big-thing.

scenario will involve greater than average reductions elsewhere, and less than average here. Consequently, the global reduction scenario, with a marginal abatement cost of $100 per ton of CO_2, is a less demanding scenario than local reduction by a similar percentage, with a marginal abatement cost of $174 per ton (even after assuming rapid future cost reduction).

8.2. Non-Embedded NO_X Costs

Combustion of natural gas, an increasingly important fuel for New England electricity generation and heating systems, gives rise to NO_X emissions. NO_X is a contributor to ground-level ozone and smog, and a cause of respiratory illness. These emissions are reduced but not eliminated by current regulations. What non-embedded costs should be associated with the residual NO_X emissions from controlled emissions?

It is often assumed that there is a decreasing marginal benefit to additional emission reduction, with the worst health effects eliminated by initial control measures, and limited, if any, gains from going further. Some recent research on NO_X challenges this assumption, finding greater benefits per ton of reduction when ambient NO_X concentrations are lower. (This would be the case if, as one group of researchers has found, the logarithm of NO_X concentration is a better predictor of mortality risk than concentration itself; a logarithmic damage curve implies greater returns per unit emission reduction when concentrations are lower.) In one study, the value of marginal benefits per ton of NO_X reduction rises from $13,000–$14,000 at 2007 baseline conditions, approaching $45,000–$51,000 at nearly 100 percent abatement. (Prices are in 2007 dollars per metric ton, and they are not converted since we did not use them in AESC 2018.)

The fact that NO_X damages depend on local ambient concentrations (unlike, say, damages from GHG emissions) implies that damage costs vary significantly from one location to another. One alternative would be a massive research effort to develop location-specific costs throughout New England. To avoid this very extensive and separate level of effort, we used one study's published averages for the continental United States in the early 2000s: Converted to 2018 dollars per short ton of N (and rounded to the nearest $100), it found a low case of $6,900, a median of $31,000, and a high case of $61,700.[145]

The median cost, $31,000 per ton of N, is a reasonable estimate that seems consistent with other research. Note that, based on molecular weights, a price per ton of N implies a lower price per ton of NO_X: a reduction of 53 percent for NO, or 70 percent for NO_2. Assuming a 50/50 mix of NO and NO_2, and the NO_X emissions rates assumed for a new natural gas-fired combustion turbine described in Table 30, this implies a wholesale avoided cost for NO_X of $1.58 per MWh.

[145] Daniel J. Sobota, Jana E. Compton, Michelle L. McCrackin, and Shweta Singh (2015), "Cost of reactive nitrogen release from human activities to the environment in the United States," *Environmental Research Letters* 10, 025006. Calculated from Table 1, assuming $1.00 in 2008 = $1.174 in 2018.

Why are these cost estimates so high, in the tens of thousands of dollars per ton? Although many damage categories are considered in the research literature that derives these costs, the largest cost by far is human mortality caused by the increased burden of respiratory disease.[146] Monetary valuation of mortality, in cost-benefit analyses, typically uses a concept called the "value of a statistical life" (VSL). The VSL is calculated as the amount that an average person would pay for a small reduction in mortality risk, scaled up to a cost per life—for example, if a one in a million reduction in mortality risk is worth $9, then the VSL is $9 million. EPA's current recommended value is $7.4 million in 2006 dollars, which is equivalent to $9.2 million in 2018 dollars.[147]

If such values were consistently applied in policymaking (which they are not, at present), the effects on fossil fuel use and other pollution sources would be profound. A 2011 article in a leading economics journal found that, using conventional valuations of air pollution externalities, oil- and coal-fired power plants would have negative value added, even in the absence of a carbon price.[148] Their results also imply that gas-fired plants would have negative value added at a carbon price of $7/ton CO_2 or greater. In other words, consistently incorporating valuation of air pollution externalities, based largely on mortality risk and the VSL, would greatly accelerate the search for clean energy alternatives, even in the absence of a substantial carbon price.

[146] In addition to Sobota et al. (2015), see also Melissa B.L. Birch, Benjamin M. Gramig, William R. Moomaw, Otto C. Doering III, and Carson J. Reeling (2011), "Why Metrics Matter: Evaluating Policy Choices for Reactive Nitrogen in the Chesapeake Bay Watershed," *Environmental Science and Technology* 45, 168-174.

[147] U.S. EPA, "Mortality Risk Valuation," https://www.epa.gov/environmental-economics/mortality-risk-valuation.

[148] Nicholas Z. Muller, Robert Mendelsohn, and William Nordhaus (2011), "Environmental Accounting for Pollution in the United States Economy," *American Economic Review* 101, 1649-1675.

9. DRIPE

Demand Reduction Induced Price Effect (DRIPE) refers to the reduction in prices in the wholesale markets for capacity and energy—relative to the prices forecast in the Reference case—resulting from the reduction in quantities of capacity and of energy required from those markets due to the impact of efficiency and/or demand response programs. Thus, DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.

AESC 2018 models DRIPE benefits due to reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets. DRIPE results in AESC 2018 differ from those in AESC 2015 because of differences in analytical approach, assumptions about hedging and decay, and new commodity forecasts. These differences make exact comparison difficult. In general terms:

- Electric capacity DRIPE for resources bid into the FCM is estimated at $120/kW-year (2018–2027, levelized) for the ISO New England-wide demand. Zone-on-zone DRIPE benefits are proportional to each zone's share of peak demand and range from $1.15/kW-year in Vermont to $59.14/kW-year in Massachusetts. AESC 2015, by contrast, assumed there was no electric capacity DRIPE benefit. Capacity DRIPE for un-bid resources its approximately two times higher than that of bid capacity DRIPE, but benefits accrue many years later. We find that un-bid DRIPE is worth more than bid DRIPE due to changes in capacity market fundamentals and different DRIPE effect timeframes.

- Electric energy (seasonal) zone-on-zone DRIPE effects for peak year differences range from $8/MWh lower to $16/MWh higher than AESC 2015 depending on zone, season, and year. On average, the peak-year AESC 2018 effects are $3.15/MWh higher than AESC 2015). Zone-on-ROP effects average $42/MWh higher than AESC 2015, because of reduced inter-zonal congestion and higher price elasticity estimates. Energy DRIPE is computed at the zonal level, but only presented at state and ISO levels.

- Electric energy (top hours) values vary depending on if targeting the top N load hours or top N price hours, but values are generally two to four times higher than seasonal energy DRIPE estimates.

- Natural gas supply averages 70 percent lower in AESC 2018 (levelized value of $0.07/MMBtu-reduced compared to $0.253) because of differences in scope of price changes (national rather than regional), and gas price forecast (lower). These factors which decrease DRIPE are modestly offset by the assessment that natural gas commodity is less price sensitive than previously estimated (price elasticity of supply is estimated at 1.01 in AESC 2018 compared to 1.52 in AESC 2015).

- Natural gas transportation basis coefficients are comparable, but slightly lower than AESC 2015 values. AESC 2018 assumes slower decay than AESC 2015, because of renewed doubt that "basis blowout" can be contained by either modest increases in capacity or improved scheduling.

- Oil DRIPE, new for AESC 2018, has a regional value of about $0.08/MMBtu-reduced. Oil DRIPE benefits are small because of the overall size of the market and because of low price forecasts.

- Gas-on-electric cross-DRIPE averages 64 percent higher for winter and 21 percent lower for baseload than AESC 2015. AESC 2018's values primarily diverge from those of AESC 2015 because of different assumptions about seasonal energy usage, but estimates are also affected by a slower decay schedule and different estimates of the price responsiveness of gas supply and gas basis.

- Electric-on-gas cross-DRIPE are significantly lower in AESC 2018 due to differences in assumed hedging strategy, decay schedule, and gas coefficients.

- Electric-on-gas-on-electric cross-DRIPE summer estimates are only 61 percent as large as those in AESC 2015, while the winter estimates are 23 percent higher. E-G-E DRIPE values differ from those found in AESC 2015 for the reasons listed for the G-E and E-G cross-DRIPE.

9.1. DRIPE Effects

Overview

DRIPE is a measure of the value of efficiency in terms of the reductions in wholesale prices seen by all retail customers in a given period.[149] Broadly speaking, there are four categories of DRIPE.

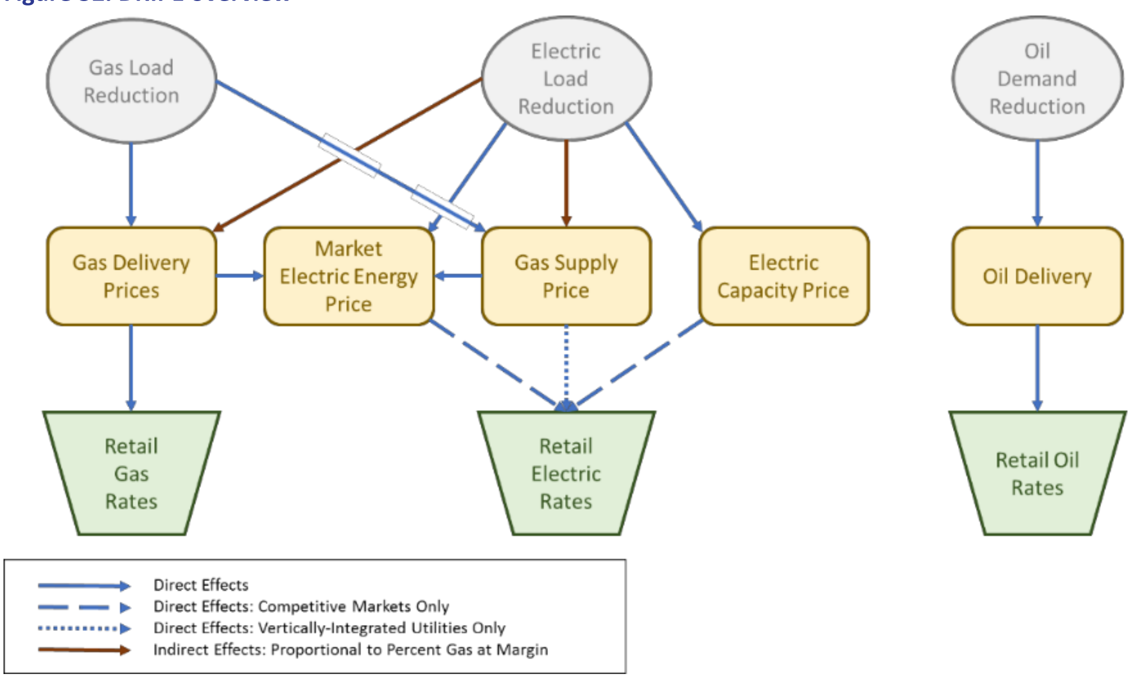
- **Own-price electricity DRIPE:** the value of reduced electricity demand on wholesale energy and capacity prices. Within this category, we estimate two components:
  - **Capacity DRIPE**, the change in state and regional electricity bills due to reductions in electric capacity prices.
  - **Energy DRIPE**, the consumer savings from reducing load, resulting in the market price being set by a plant with a better heat rate or less expensive fuel (e.g., natural gas rather than oil). These computations hold gas prices constant, avoiding any overlap with the Electric-Gas-Electric DRIPE discussed below.
- **Own-price natural gas DRIPE:** the value of reduced natural gas demand on both gas commodity prices (gas supply DRIPE) and transportation costs to New England from the production area (gas basis DRIPE).

[149] Note that in this chapter, all DRIPE values have been levelized over 10 years reflecting the short time duration of DRIPE impacts. 15-year levelized values are available in Appendix B.

- **Own-price oil DRIPE:** the value of reduced demand for petroleum products (e.g. gasoline, diesel, residual) on petroleum prices. Oil DRIPE is new for AESC 2018.
- **Cross-DRIPE:** the value that gas reductions have on electricity prices and that electricity reductions have on gas prices. Cross-DRIPE is separate from, and in addition to, own-price DRIPE values. It does not double-count any benefits.
- **Gas-to-Electric (G-E) cross-DRIPE** measures the benefits to electricity consumers that result from lower gas demand reducing gas prices for electric generation.
    - **Electric-to-Gas (E-G) cross-DRIPE** measures the benefits to gas consumers from a reduction in electricity demand and hence gas demand for generation.
    - **Electric-to-Gas-to-Electric (E-G-E) cross-DRIPE** measures the benefits of reductions in electricity demand on gas prices which in turn reduce electricity prices, even if the marginal generator does not change. E-G-E DRIPE measures the electric bill savings associated with reduction in the cost of gas for the marginal price-setting power plant, resulting from the decline in natural gas usage for electricity

The interaction of DRIPE effects are shown in Figure 32.

Figure 32. DRIPE overview



There are two elements to these estimates: magnitude and duration. The magnitude of DRIPE depends on market prices, market size, and the market price responsiveness. DRIPE benefits do not exist in perpetuity, however, so gross benefits are adjusted downward, or decayed, to reflect how other market participants respond to changes in market price over time.

AESC 2018 used several techniques—including regression analysis, equilibrium analysis, and literature review—to calculate the value of nine kinds of DRIPE effects. Natural gas commodity DRIPE and cross-DRIPE effects were modeled in AESC 2018 using the same techniques as AESC 2015. Oil commodity DRIPE, new for AESC 2018, estimated DRIPE effects using a high-level elasticity-based approach to provide indicative values.

Electric energy DRIPE was modeled in AESC 2018 using regression analysis rather than production cost modeling because we believe that regressions are easy to understand, readily auditable, and capture the key features of the system. The model used has high goodness-of-fit metrics (average R^2 = 0.74) and offers intuitive and consistent results across seasons/periods/zones. Approaches used in previous AESC studies yielded counterintuitive results in some seasons/zones (i.e., reductions in demand increasing prices), which were explained through unit commitment details. We did not find evidence of these unit-commitment impacts in our review of ISO New England historical data for the last five years.

Electric capacity DRIPE was modeled in AESC 2018 using equilibrium analysis which captures the relationship between changing system demand and the supply curve. AESC 2015 assumed capacity DRIPE does not exist because of efficient capacity markets and homogeneous resources near the margin, but the three most recent forward capacity auctions have shown that this is not the case. The marginal sources of capacity vary in price, while similar units bid into the FCAs but have not cleared at any of these prices.

Natural gas basis DRIPE effects were modeled in AESC 2018 using a regression analysis that relied on daily data on pipeline supply and basis price, while AESC 2015 relied on a high-level elasticity analysis. Basis DRIPE has a strong theoretical foundation but is difficult to measure with precision due confounding factors. The two AESC analyses yield similar results for the winter period. Empirical analysis in AESC 2018 finds that there is also a positive relationship between demand and price in non-winter months where AESC 2015 assumed no effect in the summer for theoretical reasons.

The remainder of this chapter calculates the benefits of each kind of DRIPE for each zone and for the four costing periods.

Overall DRIPE methodology

AESC 2018 provides estimates of the effect of reductions in demand and energy from energy efficiency programs on wholesale market prices for capacity and energy. We estimated DRIPE in each wholesale market in four general steps:

Step 1. We estimated the reduction in wholesale market price that results from a reduction in load, assuming all else is held constant (gross DRIPE). We estimated this impact by analyzing the relationship between the quantity of capacity or energy required and the market price.

Step 2. We reflected the timing with which load reductions would affect the markets, given the evidence on bidding strategy.

Step 3. We estimated the pace at which market participants will respond to the reduction in price with actions that offset that reduction and ultimately cause the market price to eventually return to the level it would have been under the Reference case. To estimate the pace of this offset or dissipation, we estimated the material differences in actions that suppliers would take each year in the DRIPE case relative to the actions they are projected to take under the Reference case. The pace of dissipation of capacity DRIPE will likely be different from the pace of energy DRIPE, because of the differences in the types of responses available to participants in those markets. We considered the history of proposed new generators that did not clear and either withdrew or lowered their price, as well as the relationship between capacity prices and retirement of resources. Estimating the dissipation of DRIPE involves the exercise of considerable judgment, and reasonable analysts may develop different estimates. For all types of DRIPE, we assume that DRIPE benefits end with the date of the program cessation, even if the nominal decay schedule continues for longer than the measure length.

Step 4. We estimated the percentage of net DRIPE that retail customers will experience, based upon the portion of their supply that is acquired from wholesale capacity and energy markets. This adjustment is required because various utilities own generation,[150] receive energy and capacity under contracts dating to before restructuring, and receive energy and capacity under contracts for renewable resources and other projects mandated by state policy. As a result, the actual percentage of electricity supply being acquired at prices reflecting current wholesale market prices varies among the states.

9.2. Wholesale Electric Capacity Market DRIPE Effects

This section describes the AESC 2018 methodology and assumptions for capacity market DRIPE effects, discusses why we believe these effects are both real and material, and presents estimates for the value of capacity DRIPE. AESC 2018, like prior AESC reports, estimates the benefits of efficiency measures that clear in the ISO New England FCM. Demand-response and load-management programs that do not clear in the FCM (for example, peak-shaving rate design programs), also generate capacity DRIPE benefits, albeit with different timing and of different magnitudes. Treatment of Capacity DRIPE in Appendix B mirrors the treatment of avoided capacity costs for programs that follow a similar bidding strategy. This section first calculates DRIPE benefits for cleared resources, then calculates the benefits for uncleared resources, and finally presents the combined benefit of a resource which is partially bid into the FCM.

AESC 2018 estimates capacity DRIPE coefficients from the slopes of the FCA supply and demand curves (using the results of the most recent FCA for future auctions). Chapter 5 above describes the operation of the ISO New England capacity market, recent results, the AESC 2018 forecast of capacity prices and reserve margins, and the delayed effect of load reductions that do not clear in the capacity market.

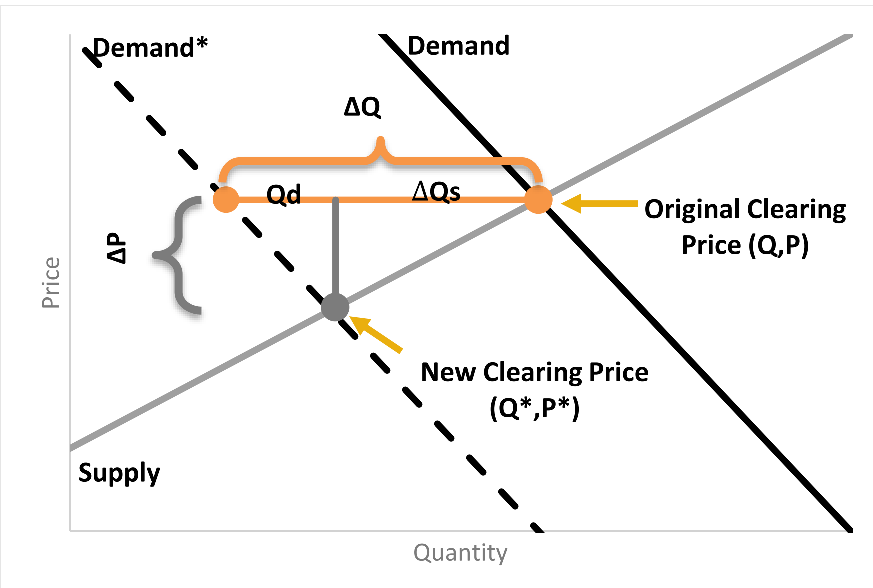
[150] Investor-owned utilities in Vermont and public utilities in Vermont, Massachusetts, and Connecticut.

The 2015 AESC Study posited that markets were in equilibrium and that marginal sources of capacity would have similar cost characteristics.[151] As discussed in Chapter 5, the results from the four most recent FCAs have shown that this is not the case. The marginal sources of capacity vary in price, with some units clearing and others not. The bid prices for individual units appear to have declined over time, as well. And high prices and major new generation additions can be followed by lower prices, resulting in no new units clearing. Hence, the clearing price of capacity continues to be sensitive to the amount of energy efficiency resources cleared in the FCM, and to the effect of uncleared energy efficiency resources on demand.

Capacity DRIPE for resources bid into the FCM

All else equal, a decrease in demand or an increase in supply will reduce the clearing price by the same amount.[152] Figure 33 illustrates how market prices change with demand. In this example, demand was reduced by ΔQ, shifting the overall demand curve to the left (from "Demand" to "Demand*"). The market clearing price falls from point (Q,P) to point (Q*,P*).

Figure 33. Generalized analysis of price change for a known change in demand



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151 AESC 2015, p. 6-9

152 In the ISO New England capacity market, demand resources are treated like supply resources, except that demand resources are credited with avoided losses of 8%. Since ISO New England attempts to maintain supply above the level of peak demand, reducing peak loads by one megawatt will move the demand curve by more than one megawatt, accounting for the effect of the lower load on the installed capacity requirement. ISO New England does not reflect this effect for the capacity that clears in the FCM, so a demand resource that does not clear can potentially shift prices more than if it would if it did clear. As discussed below, the forecasting process reduces the benefit of non-cleared energy efficiency savings.

The price shift (P to P*) per MW can be calculated from the supply curve slope and demand curve slope using Equation 2. (Note that the slopes are stated in absolute value; the actual slope of the demand curve is negative.)

Equation 2: Change in market clearing price from a 1-unit reduction in demand[153]

$$\Delta P = \Delta Q \frac{\text{Supply slope } \times \text{ Demand slope}}{\text{Supply slope} - \text{ Demand slope}}$$

Table 63 shows the slope of recent supply curves, from Chapter 5.

Table 63. Slope of FCA results by round ($/kW-month per MW of supply)

	Slope from Round			
	1 to 2	**2 to 3**	**3 to 4**	**4 to 5**
FCA 12	$0.1923	$0.0893	$0.00038	
FCA 11	$0.0750	$0.0390	$0.0025	$0.00050
FCA 10	$0.2727	$0.0074	$0.0014	
FCA 9	$0.0556	$0.0027		

Removing the post-2017 energy efficiency resources would shift the end of FCA 11 to round 4; the number of rounds and hence the final supply-curve slope would not have been affected by removing new energy efficiency from the other three FCAs.

Table 64 summarizes the demand-curve slope (from Chapter 5), supply-curve slope (from Table 63), and the price shift for a megawatt of added supply or reduced demand (including reserve margin). The price shift is lowest in FCA 12 to FCA 15, in the flat part of the supply curve, and rises dramatically in FCA 16. The dramatic increase in price shift between 2024 and 2025 is a product of the near-vertical portion of the FCA 12 supply curve.

153 A narrative description and derivation of this formula, and a demonstration that a shift in demand is equivalent to a shift in supply are attached as Appendix H. DRIPE Derivation.

Table 64. Computation of price shift from demand and supply curve slopes

Summer	FCA	Reserve Margin	Clearing Price	Demand slope	Supply Slope	Price Shift	Price Shift for Unbid Capacity
			($/kW-m)	($/kW-m/MW)	($/kW-m/MW)	($/kW-m/MW)	($/kW-m/MW)
		a		*b*	*c*	*d = b × c ÷ (c–b)*	*e = a x d*
2018	9	1.17	$9.81	-$0.0046	$0.0027	-0.0017	-0.0020
2019	10	1.20	$7.28	-$0.0044	$0.0014	-0.0011	-0.0013
2020	11	1.22	$5.35	-$0.0043	$0.0025	-0.0016	-0.0019
2021	12	1.18	$4.74	-$0.0043	$0.0004	-0.0003	-0.0004
2022	13	1.18	$4.84	-$0.0044	$0.0004	-0.0003	-0.0004
2023	14	1.18	$4.94	-$0.0042	$0.0004	-0.0003	-0.0004
2024	15	1.18	$5.22	-$0.0044	$0.0004	-0.0003	-0.0004
2025	16	1.17	$5.65	-$0.0047	$0.0893	-0.0045	-0.0052
2026	17	1.17	$6.13	-$0.0050	$0.0893	-0.0047	-0.0055
2027	18	1.17	$6.60	-$0.0053	$0.0893	-0.0050	-0.0058
2028	19	1.15	$7.07	-$0.0057	$0.0893	-0.0054	-0.0062
2029	20	1.15	$7.54	-$0.0061	$0.0893	-0.0057	-0.0065
2030	21	1.17	$6.60	-$0.0053	$0.0893	-0.0050	-0.0058
2031	22	1.15	$7.07	-$0.0057	$0.0893	-0.0054	-0.0062
2032	23	1.15	$7.54	-$0.0061	$0.0893	-0.0057	-0.0065
2033	24	1.17	$6.60	-$0.0053	$0.0893	-0.0050	-0.0058
2034	25	1.15	$7.07	-$0.0057	$0.0893	-0.0054	-0.0062
2035	26	1.15	$7.54	-$0.0061	$0.0893	-0.0057	-0.0065

Load exposed to market capacity price

The price shift coefficients measured in Table 64 are applied to each kilowatt of capacity that customers purchase from the market. Market purchases are equal to gross load of each state, plus a reserve margin, multiplied by the percentage of the state's load that is purchased in the market. Vermont utilities are vertically integrated and own (or have under long-term contract) a large portion of their capacity requirements. The same is also true for municipal utilities. The Connecticut utilities have contracts for differences with a number of generators built to relieve a transmission constraint, and all the restructured states have some legacy contracts and/or small post-restructuring contracts that provide capacity. In general, the long-term purchase of capacity has fallen out of favor, even where the utilities are purchasing energy long term.[154]

[154] In addition, the generation-supply offers by the utilities, municipal aggregators, and third-party marketers provide short-term price certainty for a sizable portion of load. By the time those rates are locked in, the capacity price is generally known. For the small percentage of power-supply contracts for more than three years into the future, the capacity component is generally subject to market adjustment. Hence, retail power-supply contracts have little if any value in hedging capacity price risk.

Table 65. Capacity entitlements and capacity-market exposure by state

	Contracts & VT Owned (MW)						Public Utilities Entitlements (MW)						Load Hedged for Capacity (MW)					
Year	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT
2017	1296	263	30	88	87	777	141	598	26	16	5	0	1232	738	48	89	79	666
2018	1296	194	30	88	87	777	141	605	26	16	5	0	1232	685	48	89	79	666
2019	1296	194	30	79	87	790	141	612	27	16	5	0	1232	691	49	82	79	677
2020	1196	147	30	75	87	785	141	619	27	16	5	0	1146	657	49	78	79	673
2021	1196	147	30	75	87	754	142	626	27	16	5	0	1147	663	49	78	79	646
2022	1196	147	30	72	87	733	143	633	28	16	5	0	1147	669	49	76	79	628
2023	1196	147	30	68	87	733	144	641	28	17	5	0	1148	676	50	72	79	628
2024	1196	140	30	59	87	733	144	649	28	17	5	0	1149	676	50	65	79	628
2025	1136	140	30	59	87	733	145	657	28	17	5	0	1098	683	50	65	79	628
2026	1136	140	30	59	87	733	146	665	29	17	5	0	1099	690	50	65	79	628

Notes: Publicly owned utility peak demand entitlements as share of state load are estimated at CT=4%, MA=9.7%, ME=2.7%, NH=1.3%, RI=0.5%, VT=0%, half of which are assumed to be hedged. Net entitlements are assumed at 50 percent of gross. When calculating total hedged capacity, contracts and entitlements are decreased by the reserve requirement of 14.3%.

Table 66. Capacity purchases by FCM

	Gross Capacity (GW)						Hedged Capacity (GW)						GW Purchased at FCM Price					
Year	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT
2017	7.0	12.3	2.0	2.5	1.9	1.9	1.2	0.7	0.0	0.1	0.1	0.7	5.8	11.6	1.9	2.4	1.8	1.2
2018	7.0	12.4	2.0	2.5	1.9	1.9	1.2	0.7	0.0	0.1	0.1	0.7	5.8	11.7	1.9	2.4	1.8	1.2
2019	7.0	12.6	2.0	2.5	1.9	1.9	1.2	0.7	0.0	0.1	0.1	0.7	5.8	11.9	1.9	2.4	1.8	1.2
2020	7.0	12.7	2.0	2.5	1.9	1.9	1.1	0.7	0.0	0.1	0.1	0.7	5.9	12.1	2.0	2.5	1.8	1.2
2021	7.0	12.9	2.0	2.6	1.9	1.9	1.1	0.7	0.0	0.1	0.1	0.6	5.9	12.2	2.0	2.5	1.9	1.3
2022	7.1	13.0	2.0	2.6	2.0	2.0	1.1	0.7	0.0	0.1	0.1	0.6	5.9	12.4	2.0	2.5	1.9	1.3
2023	7.1	13.2	2.1	2.6	2.0	2.0	1.1	0.7	0.0	0.1	0.1	0.6	6.0	12.5	2.0	2.5	1.9	1.3
2024	7.2	13.3	2.1	2.6	2.0	2.0	1.1	0.7	0.0	0.1	0.1	0.6	6.0	12.7	2.0	2.6	1.9	1.4
2025	7.2	13.5	2.1	2.7	2.0	2.0	1.1	0.7	0.1	0.1	0.1	0.6	6.1	12.8	2.1	2.6	1.9	1.4
2026	7.2	13.7	2.1	2.7	2.0	2.0	1.1	0.7	0.1	0.1	0.1	0.6	6.1	13.0	2.1	2.6	2.0	1.4

Capacity prices cannot be affected by future energy efficiency measures in the years for which capacity prices have been determined by auction. But those prices have already been reduced by the amount of demand reductions bid into FCA 9 to FCA 12 and actual load reductions reflected in the ISO's historical data. For the load forecast (such as the 2016 forecast used in FCA 11 for 2020/21) the ISO assumes that no program-related demand-side load reductions occur in intervening years (in the case of FCA 11; those would be: 2017, 2018, and 2019) beyond those that have cleared in the intervening FCAs. Thus, we treated capacity DRIPE effects as starting in 2018 for the portion of resources that clear in the FCM, and in 2021 for those that do not. The capacity DRIPE effect would likely not last indefinitely. Over time, customers will respond to lower energy prices by using somewhat more energy (including at peak). In addition, lower capacity prices may result in the retirement of some generation resources and termination of some demand-response resources (removing them from the supply curve). Further, some new proposed resources that have not cleared for several auctions may be withdrawn (if, for example, contracts and approvals expire, raising the cost of offering the resource into future auctions). Unfortunately, the historical record of retirements and cancelation of planned generation does not show any clear association with falling capacity prices. AESC 2018 has developed the following phase-out of DRIPE effects, based on the assumption that a reduction in price will result in offsetting reductions in supply, over a period of six years (Table 67).

Table 67. Capacity DRIPE decay schedule

Year	Decay Factor (δ)	Share of Capacity Undecayed (1-δ)
1	0%	100%
2	17%	83%
3	33%	67%
4	50%	50%
5	67%	33%
6	83%	17%
7	100%	0%

The value of capacity DRIPE can be calculated using Equation 3 and Equation 4. Zone-on-ROP DRIPE can be computed directly or by subtracting the value of zone-on-zone DRIPE from the value of ISO-wide capacity DRIPE. Both equations depend on the annual DRIPE coefficients (Table 64), the quantity of capacity subject to the FCM (Table 66) and the decay schedule (Table 67).

Equation 3. Value of inter-zonal (zone-on-zone) electric capacity DRIPE

$$Capacity\ DRIPE_{\substack{Zone\ Z\ |\ Zone\ Z \\ Period\ P}} = \left[DRIPE_{Coef} \times Q_{\substack{Zone\ Z \\ Period\ P}}\right] \times (1-\delta)$$

Equation 4. Value of inter-zonal (zone-on-ROP) electric capacity DRIPE

$$Capacity\ DRIPE_{\substack{ROP\ |\ Zone\ Z \\ Period\ P}} = \left[DRIPE_{Coef} \times \left(Q_{\substack{ISO \\ Period\ P}} - Q_{\substack{Zone\ Z \\ Period\ P}}\right)\right] \times (1-\delta)$$

$$Capacity\ DRIPE_{ROP\ |\ Zone\ Z} = Capacity\ DRIPE_{ISO\ |\ ISO} - Capacity\ DRIPE_{Zone\ Z\ |\ Zone\ Z}$$

Where,

$Q_{Zone\ Z}$ is the capacity subject to market price in a given zone (MW)

Q_{ISO} is the capacity subject to market price across the ISO, equal to $\sum Q_{Zone\ Z}$

δ is the decay factor representing rebound effects and decisions by generators about operation and new entry.

Table 68 presents the value of intra-zonal and inter-zonal capacity DRIPE for each zone, measured in units of $/kW-year.

Table 68. Capacity DRIPE by year (2018 installations cleared in FCA 9)

	Net Zone-on-Zone Capacity DRIPE ($/kW-year)						
Period	ISO	CT	ME	MA	NH	RI	VT
2018	486.95	117.57	39.23	239.64	48.91	9.97	4.75
2019	255.01	61.08	20.55	125.95	25.76	4.98	2.36
2020	310.34	74.53	24.89	153.41	31.26	6.15	2.89
2021	51.70	12.35	4.14	25.58	5.20	1.15	0.54
2022	34.56	8.22	2.77	17.11	3.48	0.83	0.38
2023	17.92	4.25	1.44	8.89	1.80	0.43	0.20
2024	0	0	0	0	0	0	0
Levelized (2018–2027)	119.88	28.82	9.64	59.14	12.07	2.44	1.15
Levelized (2018–2033)	82.03	19.72	6.60	40.47	8.26	1.67	0.79

	Net Zone-on-ROP Capacity DRIPE ($/kW-year)						
Period	ISO	CT	ME	MA	NH	RI	VT
2018	0	369.38	447.72	247.31	438.03	476.98	482.19
2019	0	193.92	234.45	129.06	229.24	250.03	252.65
2020	0	235.82	285.46	156.93	279.08	304.20	307.46
2021	0	39.35	47.56	26.12	46.50	50.55	51.16
2022	0	26.34	31.79	17.45	31.09	33.73	34.18
2023	0	13.68	16.49	9.04	16.12	17.49	17.73
2024	0	0	0	0	0	0	0
Levelized (2018–2027)	0	91.06	110.24	60.73	107.81	117.44	118.73
Levelized (2018–2033)	0	62.31	75.43	41.56	73.77	80.36	81.24

This table assumes that capacity is fully bid into the first FCM. DRIPE benefits for cleared capacity should be assumed to end with the date of the program cessation, even if the nominal decay schedule continues for longer than the measure length. So, if a program generates benefits in 2018 but is ended thereafter, ISO DRIPE benefits total $486.95/kW-year in 2018 and are nil in subsequent years.

Capacity DRIPE from uncleared demand response

Demand-response and load-management programs that do not clear in the FCM also generate capacity DRIPE benefits, albeit with different timing and of different magnitudes. The cautions discussed in Chapter 5 apply here, as well.

Capacity DRIPE for uncleared resources is calculated analogously to that of cleared resources, but the decay schedule and market clearing prices are adjusted to reflect different market features. As noted in Chapter 5, installed but uncleared capacity affects the FCM five years after it is first installed. As discussed in Chapter 5, DRIPE effects from uncleared programs start later than those bid into the market and are assumed to "ramp up" over a multi-year period. All things equal, these later benefits are less valuable, due to discounting. However, based on the capacity price forecast developed in Chapter 5, reductions in those later years are actually more valuable than those in the short term, due to larger price-shift coefficients in later years.

The price shift from uncleared load reductions depends on the price shift coefficient (as for the cleared resources) but also the reserve margin and the period over which a program is in effect. As discussed in Chapter 5, capacity DRIPE from uncleared savings start later than those cleared into the capacity market and increases over a multi-year period.

ISO New England generates its capacity forecast using a complex regression analysis of load, weather, and a time trend over 15 years of historical summer (July and August) daily peak loads. As load reductions from efficiency programs appear in the model's source data, forecasts of capacity requirements are reduced. This means that uncleared capacity DRIPE phases in over a period of years. Phase in is non-linear, depending on the duration of load reductions and when in the 15-year dataset the reductions occur. If a program reduces peak loads in the recent years of the historical dataset, the time trend coefficient in the model is reduced (and hence the forecast), all else equal. It takes approximately five years of reductions before the full benefit is realized.[155] Figure 34 depicts the mechanism by which these lower forecasts originate for a one-year duration program, while Figure 35 depicts a five-year program.

Figure 34. Single-year load reductions shifting the peak forecast

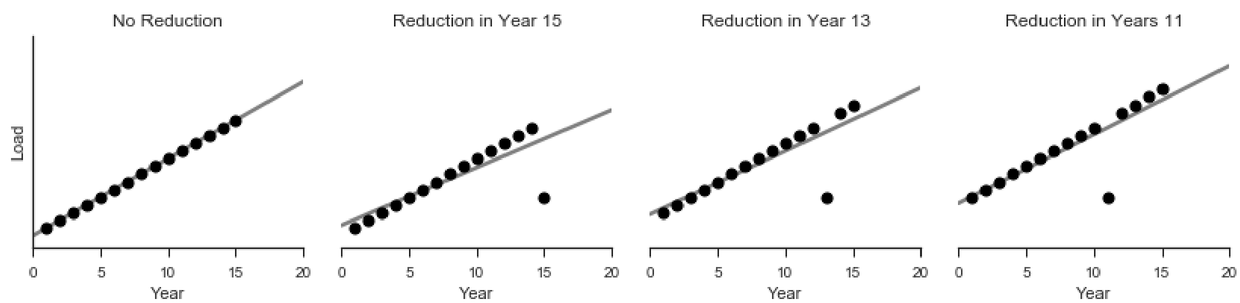
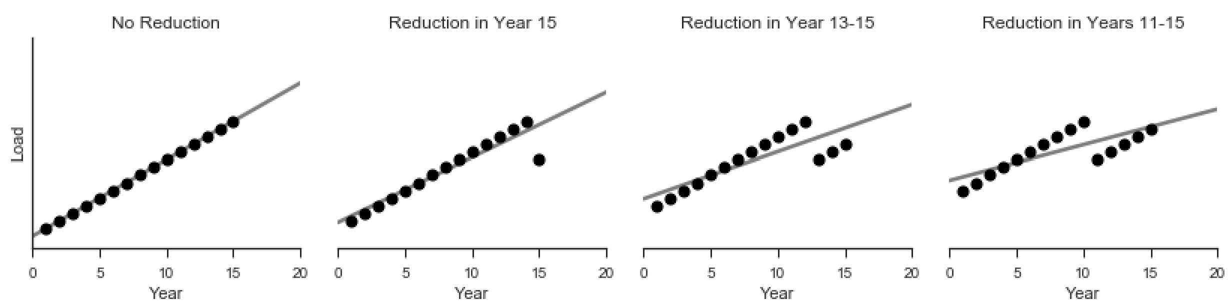


Figure 35. Multi-year load reductions shifting the peak forecast



[155] The effect of the load reduction on the coefficients of the weather variables is less predictable and depends on the weather conditions on the days affected by the program.

In each stylized plot, the black dots reflect historical load data, with the right-most dot being the most recent year. The grey line is a simple best-fit linear regression continuing for five years into the future.[156] In each of the figures, the left-most example shows the base case, with 15 years of data and no reduction in load. The second example shows the effect of a one-year load reduction on a linear regression when that load reduction occurs in the most recent year (Year 15). In Figure 34, the next example shows the situation two years later, when the reduction is in Year 13 of the 15-year data set that ISO New England would be using then, and the final example shows the situation four years after the program's operation, when the reduction is in Year 11 of the dataset. The single-year load reduction has the largest effect on the forecast when it is at the end of the data, in Year 15. When the reduction has aged to Year 13 and (even more) Year 11, the effect is more modest, because the critical point is more towards the center of the 15-year time series rather than on the edge.

The third example in Figure 35 depicts the effect of load reductions in the last three years, while the last example shows the effect of five years of program operation. The program's effect on the forecast increases with multiple years of operation, flattening the trend line further for each year that the load reduction continues. After five years of program operation, the load reduction would be fully reflected in the forecast, although the full reduction would not affect capacity prices for another five years. A program lasting more than five years would have the same forecast effect as a five-year program. Mathematically speaking, the value of a five-year reduction is equal to the cumulative effect of five one-year reductions. For a program installed in 2018, the first effects are felt in 2023 and the complete effects arrive in 2027.

As with traditional capacity DRIPE, benefits decay over time as market participants react to the reduced price of capacity. Table 69 depicts how the phase in occurs for a five-year program, as well as how it decays. The phase-in and decay years are reflected in relative terms, where the reduction first occurs in Year "N." For example, if the reductions start in 2018, then N=2018. As noted above, there is a five-year lag between when reductions occur and when capacity obligations are first reduced (N+5 = 2023).

[156] The loads in Years 1 through 15 would be used to develop the forecast in Year 16, which would be applied in Year 17 to develop the forecast for the summer of Year 20, which will be used in the forward capacity auction for the commitment period of Years 20/21.

Table 69. Phase-in and decay of non-cleared capacity DRIPE

Year	Phase In (%) N	N+1	N+2	N+3	N+4	N+5	% in forecast	Simplified Phase In (%)	Decayed Phase In (%) N	N+1	N+2	N+3	N+4	N+5	Net Effect (%)
N+5	27						27	*30*	*30*						**30**
N+6	24	27					50	*20*	25	*20*					**45**
N+7	21	24	27				71	*20*	20	17	*20*				**57**
N+8	18	21	24	27			90	*20*	15	13	17	*20*			**65**
N+9	15	18	21	24	27		105	*10*	10	10	13	17	*10*		**60**
N+10	12	15	18	21	24	27	117	*0*	5	7	10	13	8	*0*	**43**
N+11	10	12	15	18	21	24	100		0	3	7	10	7	0	**27**
N+12	7	10	12	15	18	21	83		0	0	3	7	5	0	**15**
N+13	4	7	10	12	15	18	66		0	0	0	3	3	0	**7**
N+14	1	4	7	10	12	15	49		0	0	0	0	2	0	**2**
N+15	0	1	4	7	10	12	33		0	0	0	0	0	0	**0**
N+16	0	0	1	4	7	10	21		0	0	0	0	0	0	**0**
N+17	0	0	0	1	4	7	11		0	0	0	0	0	0	**0**
N+18	0	0	0	0	1	4	5		0	0	0	0	0	0	**0**

Each successive phase-in column has the same series of values (equal to the effect of a one-year program), offset by one year. The percentage of the actual load reduction integrated into the forecast is the sum of the effect from each program year.[157]

The capacity market would be expected to respond to the *cumulative* effect of the program on the load forecast and hence on the administrative demand curve. Because of the complexity associated with these forecast reductions, we approximate the incremental phase-in schedule using simplified blocks (as shown in Table 69).

Benefits decay over time as market participants react to the reduced price of capacity. The multi-year ramp up, results in the various portions of the load reduction starting to decay in different years. For example, the 30 percent of load in Year N+5 starts decaying a year sooner than the next 20 percent of load reduction, and so on. The sum of these multiple decayed forecast streams, shown in the Net Effect column of Table 69, sums the percentage of the load reduction that affects the capacity auctions, after accounting for decay.

[157] This modeling is a simplification to facilitate screening. In some simple trend-line examples, the forecast can actually fall by slightly more than the full load reduction in some years. Given the effects of other variables on the regression equation, and the uncertainties in the decay schedule, greater complexity in modeling the capacity DRIPE effect does not seem warranted.

Programs that last fewer than five years have different decay schedules than those lasting five years or more. Table 70 shows the net effect on the capacity auctions, as a percentage of the load reduction for programs operated for various numbers of years.

Table 70. Decay schedules for un-cleared capacity resources yielding reductions for 1 to 5 years

	Net Responsive for a Program starting in Year N				
Year	1 Year	2 Year	3 Year	4 Year	5+ Year
N+5	30%	30%	30%	30%	30%
N+6	25%	45%	45%	45%	45%
N+7	20%	37%	57%	57%	57%
N+8	15%	28%	45%	65%	65%
N+9	10%	20%	33%	50%	60%
N+10	5%	12%	22%	35%	43%
N+11	0%	3%	10%	20%	27%
N+12	0%	0%	3%	10%	15%
N+13	0%	0%	0%	3%	7%
N+14	0%	0%	0%	0%	2%
N+15	0%	0%	0%	0%	0%

Table 71 shows the value of uncleared capacity DRIPE, using load exposed to market prices (Table 66), the price shift coefficients (Table 64), and the decayed phase-in schedule for programs lasting over four years (Table 70).

Table 71. Value of capacity DRIPE for uncleared resources by year (2018 installation)

	Net Zone-on-Zone Capacity DRIPE ($/kW-year)						
Period	**ISO**	**CT**	**ME**	**MA**	**NH**	**RI**	**VT**
2022	0	0	0	0	0	0	0
2023	37.26	8.82	2.99	18.49	3.75	0.89	0.41
2024	56.46	13.31	4.54	28.07	5.68	1.36	0.62
2025	917.15	215.26	73.70	456.88	92.46	22.25	10.05
2026	1125.38	264.73	90.23	560.66	113.15	27.37	12.28
2027	1092.73	257.10	87.57	544.09	109.81	26.77	12.00
2028	836.52	196.82	67.03	416.52	84.06	20.49	9.19
2029	546.98	128.70	43.83	272.35	54.97	13.40	6.01
2030	273.64	64.38	21.93	136.25	27.50	6.70	3.01
2031	129.14	30.38	10.35	64.30	12.98	3.16	1.42
2032	34.83	8.19	2.79	17.34	3.50	0.85	0.38
2033	0	0	0	0	0	0	0
Levelized (2018–2027)	311.01	73.13	24.95	154.90	31.29	7.57	3.41
Levelized (2018–2033)	310.20	72.95	24.88	154.48	31.20	7.57	3.40

	Net Zone-on-ROP Capacity DRIPE ($/kW-year)						
Period	**ISO**	**CT**	**ME**	**MA**	**NH**	**RI**	**VT**
2022	0	0	0	0	0	0	0
2023	0	28.44	34.27	18.77	33.51	36.37	36.85
2024	0	43.14	51.92	28.39	50.77	55.09	55.84
2025	0	701.89	843.45	460.27	824.69	894.90	907.10
2026	0	860.65	1035.15	564.73	1012.24	1098.01	1113.11
2027	0	835.63	1005.17	548.64	982.92	1065.97	1080.73
2028	0	639.70	769.49	420.00	752.46	816.03	827.33
2029	0	418.28	503.15	274.63	492.01	533.58	540.97
2030	0	209.26	251.71	137.39	246.14	266.94	270.63
2031	0	98.76	118.79	64.84	116.16	125.98	127.72
2032	0	26.63	32.04	17.49	31.33	33.97	34.44
2033	0	0	0	0	0	0	0
Levelized (2018–2027)	0	237.88	286.06	156.11	279.72	303.44	307.60
Levelized (2018–2033)	0	237.25	285.33	155.72	279.01	302.63	306.80

On a 15-year levelized basis, uncleared capacity DRIPE benefits are worth approximately three times more than the cleared capacity benefits, due to the much higher DRIPE coefficients in the late 2020s compared to those in earlier years. The dramatic increase in the price shift coefficients after 2025 results from the capacity market clearing price moving from the very shallow portion of the supply curve expected in the near future to the near-vertical portion of the supply curve, where a modest change in quantity has a large change in clearing price.

Value of capacity DRIPE for resources partially bid into the FCM

The preceding two sections developed the value of capacity DRIPE for resources clearing in the FCM and for uncleared resources. If the program administrator bids some, but not all, of a program's load reductions into the capacity market, the total value of capacity DRIPE would be equal to the weighted average of the two types of capacity DRIPE. Table 72 shows the example of a Massachusetts load reduction that starts in 2018, continues to reduce load for at least five years, and was half bid into FCA 9, the first auction for which it was eligible.

Table 72. Example of blended capacity DRIPE (Massachusetts, 2018 Installation, half in FCA 9, half unbid)

	Net Zone-on-Zone Capacity DRIPE ($/kW-Year)		
Period	***DRIPE Value for Resources Cleared in FCA 9***	***DRIPE Value for Resources Not Cleared In FCM***	***50% Blended***
2018	239.64		119.82
2019	125.95		62.98
2020	153.41		76.71
2021	25.58		12.79
2022	17.11	3.48	10.30
2023	8.89	18.49	13.69
2024	0.00	28.07	14.03
2025		456.88	228.44
2026		560.66	280.33
2027		544.09	272.04
2028		416.52	208.26
2029		272.35	136.18
2030		136.25	68.12
2031		64.30	32.15
2032		17.34	8.67
2033		0.00	0.00
Levelized (2018-2033)	83.59	211.03	96.38

Programs in other zones, installed in different years, cleared in different FCAs, or with different durations would have different effect distributions and magnitudes.

9.3. Wholesale Electric Energy Market DRIPE Effects

Similar to electric capacity DRIPE, a reduction in electricity demand should reduce wholesale energy prices, which benefits all market participants. This section describes the AESC 2018 methodology and assumptions for electric energy DRIPE, discusses the benefits and detriments of various model forms, and presents our estimates of energy DRIPE. Energy DRIPE values are presented in two ways: first, by zone, month, and period; second for the "top" 100 load or price hours. The monthly values provide DRIPE estimates for programs targeting baseline reductions while the "top" hour assessments provide estimates for more targeted applications.

Regression model selection

AESC 2018, like AESC 2013, estimates the magnitude of wholesale energy market DRIPE by year by conducting a set of regressions of historical zonal hourly market prices against regional load. This top-down approach assumes that there is an underlying relationship between prices and loads which can be represented using a single equation. This approach has the benefit that it is easy to understand and that it captures the key features of the system transparently.

Regressions also have the benefit of modeling the average relationship between price and demand and providing structure to heterogeneous data. Periods with similar demand often have very different prices (see scatterplot data in Figure 36). Price dispersion is a product of an uncertain system that contains dynamic unit commitment decisions as well as a host of other stochastics such as generator-forced outages or transmission constraints. By assessing all system price and demand data, it is possible to capture both structural trends as well as uncertain events that occurred in past years.

AESC 2015 suggested that top-down models do not capture the subtleties of unit-commitment decisions, and that production cost models should be used instead (AESC 2015, 7-7). Production cost models have the benefit of simulating how specific generators are operated in the market and they also capture the basics of price formation. The deterministic nature of production cost models will create a system where a given level of demand will always yield the same price because the same generators would be dispatched in the same way, despite empirical evidence to the contrary. Production cost models can represent some of these uncertainties if stochastic variables are liberally implemented, but they rarely capture the full range of uncertainty witnessed in real life. Worse, production cost models sometimes yield strange results for very small changes in demand; an attribute, which regression models avoid.

We considered many functional forms to describe the relationship between zonal prices and loads. We tested the significance of variables related to ISO system performance (e.g., capacity surplus, maintenance), system implied heat rate, and zonal and regional loads. After considering these candidate variables and various functional forms, we settled on a polynomial model to characterize the relationship between zonal prices and loads. The model, described in Equation 5, relates zonal price to ISO demand and to natural gas prices.

Equation 5: Regression equation relating zonal electric energy prices to ISO demand and natural gas prices

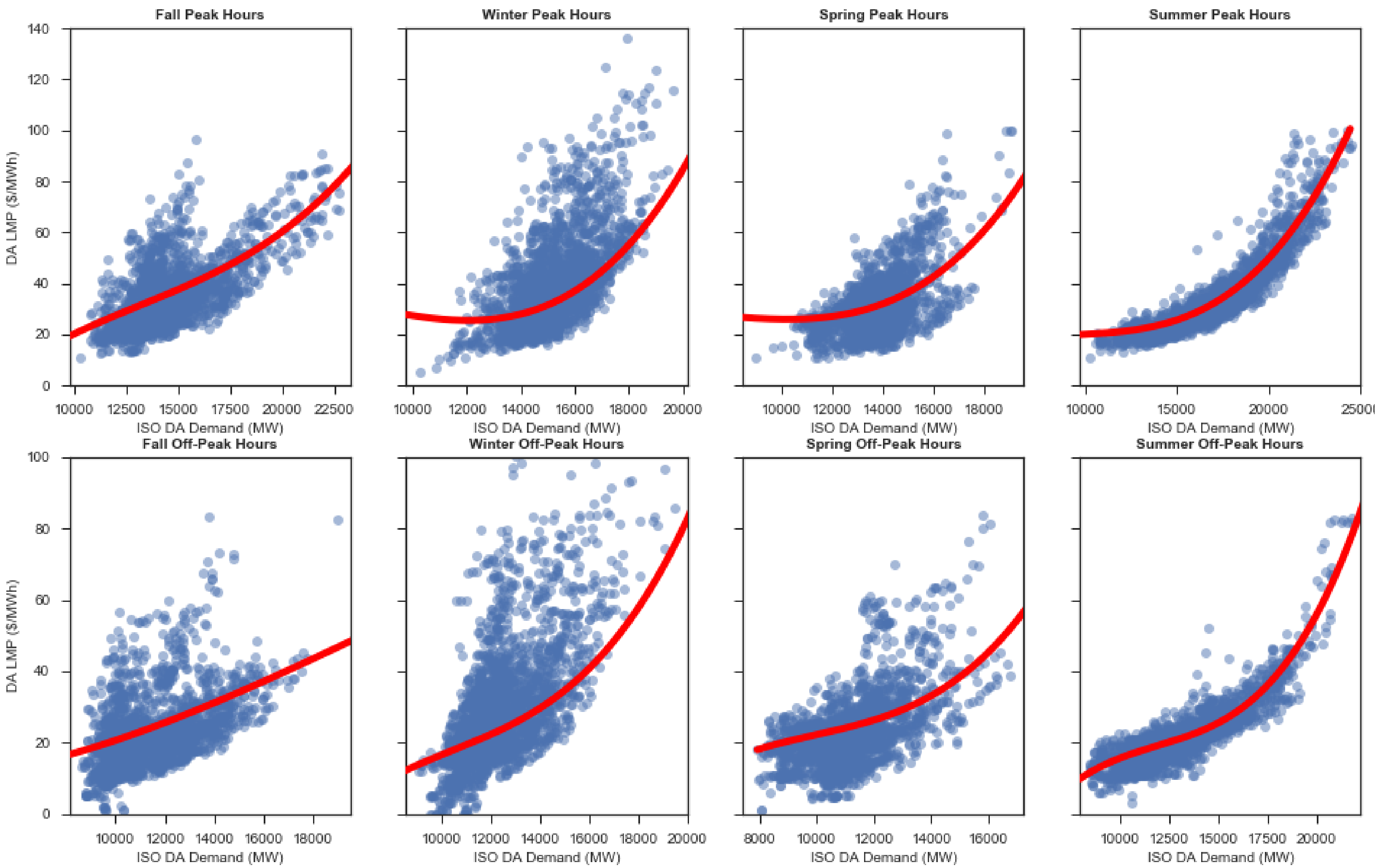
$$LMP_{Zone} = \beta_0 + \beta_1 Demand_{ISO} + \beta_2 {Demand_{ISO}}^2 + \beta_3 {Demand_{ISO}}^3 + \beta_4 Price_{NG}$$

A cubic function allows for a “hockey stick” -like profile where prices increase slowly at first, then quickly during high load periods. For example, at the extreme right side of the supply curve, when the market’s marginal unit switches from a gas peaker to a natural gas combined cycle, prices will fall by approximately 30 percent even though demand might only decrease a few MW. In the middle of the offer stack, by contrast, switching from a less efficient gas combined cycle to a more efficient one will only decrease prices by a few percent. In Equation 5, natural gas prices shift the overall curve up or down but does not skew the shape of the curve itself. This polynomial model offers five advantages over other assessed models:

1. Non-linearity that depicts very high prices at high load times and flatter prices under lower loads
2. Explicit control for natural gas prices—major driver of winter price volatility
3. Significantly better goodness-of-fit compared to linear models (e.g. R^2 or sum-of-squared errors)
4. Single functional form for all zones, months, and periods
5. Parsimonious formulation—only the key attributes are included.

Figure 36 plots actual price and demand data (in blue) against predicted data (in red) estimated using Equation 5 for the four seasons and two periods.

Figure 36. Comparing modeled electricity prices to historical (ISO New England, by season and period, 9/2015–8/2017)



Note: These charts are for descriptive purposes. To plot the fitted line in the figure, the mean natural gas price for that season and period was used—this differs from our actual analysis where different NG prices were used for each point. Final DRIPE calculations use monthly timeframes instead of quarterly; different zones have different price/load pairs. For 2018 electric energy DRIPE calculations, we relied on hourly and daily data for the two-year period September 2015 through August 2017. We relied on three datasets: (a) ISO New England's Zonal Pricing reports which provide hourly price and demand data; (b) ISO New England's Daily Capacity Status reports which provide information on the daily peak load forecast, capacity surplus, outages and reductions, and known maintenance; and (c) Platt's natural gas market data on delivered gas prices at Algonquin Citygates.

Overall, the model produces a good fit for the summer and winter periods (when price and demand is highest) and a less good fit in the spring and fall shoulder seasons, which see lower demand and lower prices but more price variability due to scheduled outages. The average R^2 value for the polynomial model, across all zones, months, and periods is 0.74 (the minimum R^2 across all zones/periods/months is 0.44, close to the average value of the linear models). The average root mean squared error (RMSE), a metric used as a measure of the differences between predicted by a model or an estimator and the values actually observed, equals $5.85/MWh.

Calculating energy DRIPE from the price/demand relationship

With a functional form established to model the relationship between price and demand, AESC 2018 finds unique DRIPE coefficients for each hourly observation by taking the derivative of the polynomial regression model (Equation 5) with respect to demand:

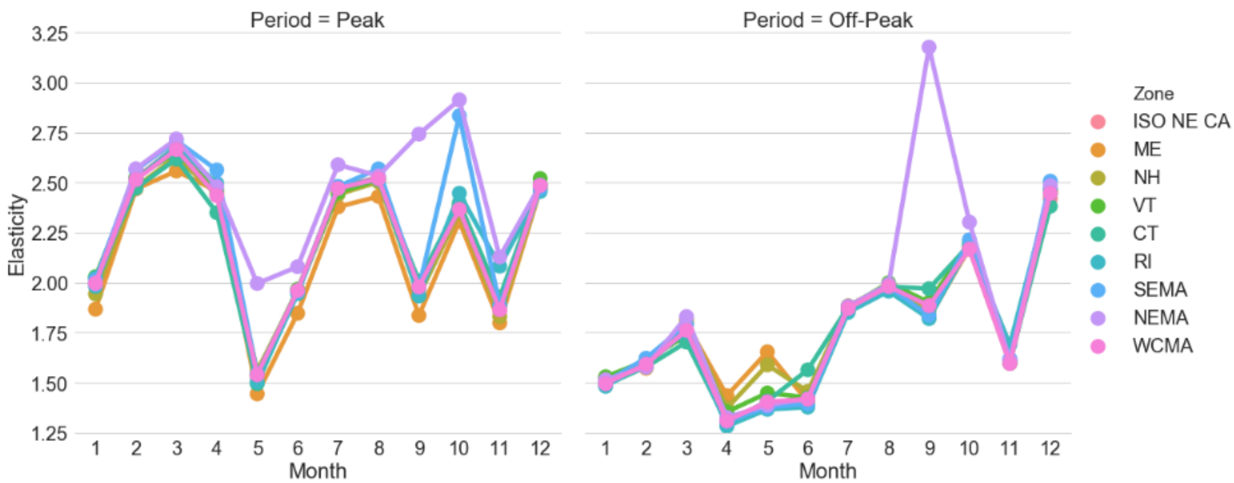
Equation 6. Calculation of hourly electric DRIPE coefficients

$$Slope = \frac{\partial LMP_{Zone}}{\partial Demand_{ISO}} = \beta_1 + 2\beta_2 Demand_{ISO} + 3\beta_3 {Demand_{ISO}}^2$$

These instantaneous slopes represent how price would change in each hour for a small change in demand. Hundreds of distinct hourly slope values are then aggregated into a single load-weighted average slope. This average slope represents the average price response to a small change in demand for a given zone/season/period. These values can be restated as load-weighted elasticities by calculating the price effect of a 1.0 percent change in demand at each point.[158] Electric energy DRIPE coefficients are presented in Figure 37 by zone, month, and period.

158 For points with very low zonal LMP, elasticities are very large. This is a biproduct of the modeling and elasticity calculation, not of any structural phenomenon. When LMP is $0/MWh, the elasticity is infinite. We exclude calculated point elasticities when zonal prices are less than $5/MWh. When LMP is $0/MWh, the elasticity is infinite. We exclude calculated point elasticities when zonal prices are less than $5/MWh. These exclusions total 722 hourly values across all zones, representing 0.04 percent of the dataset

Figure 37. Percent change in zonal price per 1.0 percent change in ISO New England demand



The results are remarkably stable across zones but vary by month and period. The modest spread in elasticity values by zone indicates zonal prices are strongly correlated with system load. A 1.0 percent reduction in load throughout New England results in a 1.25 to 2.5 percent reduction in off-peak price, and a 1.5 to 2.75 percent reduction in peak price. On an annual basis, a 1.0 percent reduction in demand yields a 2 percent reduction in price. The NEMA zone has generally higher elasticities than other zones because of zonal transmission constraints, but we expect NEMA elasticities to converge with the other zones over time.

Comparison to AESC 2013 and AESC 2015 electric energy DRIPE coefficients

The AESC 2018 DRIPE values are higher than those in previous AESC studies. AESC 2013, using a similar regression approach found that a 1.0 percent reduction in load throughout New England results in a 1.1 to 1.2 percent reduction in off-peak price, and a 1.9 to 2.2 percent reduction in peak price.[159] AESC 2015, using a system simulation approach found a 1 percent reduction in ISO load would reduce state peak prices by 0.33 percent to 1.4 percent annually, with a state-load weighted average of 0.72 percent.[160]

AESC 2018 projections are higher than those in AESC 2015, primarily due to a different analytical approach. While the simulation modeling approach attempts to capture some of the subtlety of unit commitment, the methodology does not capture some of the very non-linear price effects associated with unexpected transmission constraints or unit shut-down that drive the AESCS 2018 DRIPE values. The AESC 2018 values are also higher than those found in AESC 2013; this is primarily because the polynomial model captures the high value of reducing demand in high load hours better than a linear model.

[159] AESC 2013, page 7-8.

[160] AESC 2015, page 7-13.

DRIPE values for intrazonal and interzonal demand

The value of DRIPE is conceptually equal to the change in LMP that results from a 1 MWh reduction in demand, multiplied by the amount of load that benefits from that reduction in price. The value of DRIPE decays over time due to takeback effects and other exogenous factors. For a given period, the value of intra-zonal DRIPE (i.e., zone-on-zone) is found using Equation 7 and the value of inter-zonal DRIPE (zone-on-ROP) is found using Equation 8.

Equation 7. Value of intra-zonal (zone-on-zone) electric energy DRIPE

$$DRIPE_{\substack{Zone\ Z\ |\ Zone\ Z\\ Period\ P}} = \left[\frac{\varepsilon_{\substack{Zone\ Z\\ Period\ P}} P_{\substack{Zone\ Z\\ Period\ P}}}{Q_{\substack{ISO\\ Period\ P}}} \times Q_{\substack{Zone\ Z\\ Period\ P}}\right] \times (1-\delta)$$

Equation 8. Value of inter-zonal (zone-on-ROP) electric energy DRIPE

$$DRIPE_{\substack{ROP\ |\ Zone\ Z\\ Period\ P}} = \frac{1-\delta_{Period\ P}}{Q_{\substack{ISO\\ Period\ P}}} \sum_{\substack{x \in Zones\\ x \neq Zone\ Z}} \varepsilon_{\substack{x\\ Period\ P}} P_{\substack{x\\ Period\ P}} Q_{\substack{x\\ Period\ P}}$$

Where,

ε is the supply elasticity of price;

P is the zonal market energy price ($/MWh);

$Q_{Zone\ Z}$ is load subject to the market price, and is equal to gross zonal demand less hedged supply;

Q_{ISO} is ISO energy load;

δ is the decay factor representing rebound effects and decisions by generators on operation and new entry.

The first term in Equation 7 calculates the change in zonal price given a change in ISO demand. It is multiplied by the load in Zone Z to calculate the collective benefit of that price reduction. The gross DRIPE benefits are then decayed to reflect how market participants will change their behavior in response to the price reduction. Equation 8 is similar, but reflects how the demand reduction in Zone Z reduces prices in all other zones.

Zone-on-zone DRIPE values are roughly proportional to the percentage of ISO load in a given zone. Zones with less load will have lower zone-on-zone energy DRIPE values than zones with higher load. For example, Maine accounts for roughly one-fifth as much load as Massachusetts and has a zone-on-zone DRIPE value approximately one-fifth as large (there are subtle differences that make comparison inexact because DRIPE also depends on zonal elasticity and hedging estimates). Zone-on-ROP estimates are approximately proportional to the difference between ISO load and zonal load. Zones with lower load will have higher zone-on-ROP values.

As is true for capacity DRIPE, energy DRIPE is applicable only to energy purchased at market prices, and the effect of DRIPE decays over time. In addition, while energy DRIPE starts immediately (there is no floor price in the energy market), most energy purchased at market price for retail load is priced months or a couple years in advance of delivery, through utility contracting for standard service or a third-party contract. Hence, the magnitude of energy DRIPE is reduced in the early years following measure implementation. Hedging includes:

- Investor-owned utility contracts (pre-restructuring legacy contracts, post-restructuring reliability contracts in Connecticut, renewables purchases, and utility-owned resources in Vermont);
- Generation resources owned by PSNH; and
- The load of the public utilities (municipals and coops), estimated from the percentage of sales in each state that are from the public utilities, and assuming that the public utilities are hedged to the same extent as Vermont.

In addition to hedging, some load is also subject to short-term contracts. Based on our knowledge of the procurement policies for standard service, the length of third-party contracts, and information provided by some of the participating utilities, we estimated that 50 percent of energy is pre-contracted for the year of measure installation, 20 percent in the following year, and 10 percent in the third year.

Adjusting gross load for hedging and short-term contracts yields the amount of load that is responsive to price changes from load reduction. DRIPE benefits installed in a given year, however, do not continue in perpetuity. We estimated the phase-out of energy DRIPE (decay) based upon four factors:

- Over time, customers would respond to lower energy prices by using somewhat more energy, pushing prices back up somewhat.[161]
- Lower loads would reduce acquisition mandates under renewable and other alternative energy standards that specify the percentage of energy that must be provided by various categories of resources. The reduced acquisition of renewables would tend to increase prices.
- Owners of existing generating capacity would tend to allow their energy-producing assets to become less efficient and less reliable as low energy prices make continued operation of the units less attractive, leading to more outages and higher market-clearing prices.
- The addition of new resources would tend to be delayed, and the mix of new resources would tend to be shifted toward peaking plants.

Decay schedules for efficiency measures of different vintages are similar but not identical due to different ISO-wide RPS requirements. Table 73 depicts the magnitude of hedging, short-term contracts, and decay by year. Short-term contracts and decay are provided as separate schedules for measures installed in 2018 and 2019.

[161] A meta-analysis of take-back effects can be found in Gillingham et al, "The Rebound Effect and Energy Efficiency Policy" (2015) http://environment.yale.edu/gillingham/GillinghamRapsonWagner_Rebound.pdf.

Table 73. Hedging, short-term contracts, and decay by year

	Unhedged Load to Gross Load Ratio							Short-Term Contracts			Decay		
Year	ISO	ME	NH	VT	CT	RI	MA	2018	2019	2020	2018	2019	2020
2018	83%	94%	89%	37%	72%	96%	89%	50%			14%		
2019	84%	94%	90%	37%	72%	96%	89%	20%	50%		19%	16%	
2020	84%	94%	90%	37%	72%	96%	89%	10%	20%	50%	22%	19%	16%
2021	83%	94%	90%	37%	71%	95%	89%	0%	10%	20%	30%	23%	20%
2022	83%	94%	90%	37%	71%	95%	89%	0%	0%	10%	36%	30%	24%
2023	76%	94%	90%	37%	71%	95%	74%	0%	0%	0%	49%	36%	30%
2024	76%	94%	90%	38%	71%	95%	74%	0%	0%	0%	61%	50%	37%
2025	76%	94%	90%	38%	71%	95%	72%	0%	0%	0%	72%	62%	50%
2026	75%	94%	90%	38%	71%	95%	70%	0%	0%	0%	85%	73%	62%
2027	75%	94%	90%	38%	71%	95%	70%	0%	0%	0%	92%	86%	73%
2028	75%	94%	90%	38%	71%	95%	70%	0%	0%	0%	100%	92%	86%
2029	75%	94%	90%	38%	71%	95%	70%	0%	0%	0%	100%	100%	92%
2030	75%	94%	90%	38%	71%	95%	70%	0%	0%	0%	100%	100%	100%

Combining these three components, Table 74 calculates the share of gross load which is DRIPE responsive for measures installed in 2018 and 2019.

Table 74. Share of gross load which is responsive to energy DRIPE

	DRIPE Responsive share of Load (2018 Installs)							DRIPE Responsive share of Load (2019 Installs)						
Year	ISO	ME	NH	VT	CT	RI	MA	ISO	ME	NH	VT	CT	RI	MA
2018	36%	40%	38%	16%	31%	41%	38%	0%	0%	0%	0%	0%	0%	0%
2019	54%	61%	58%	24%	47%	63%	58%	42%	42%	42%	42%	42%	42%	42%
2020	59%	66%	63%	26%	50%	67%	63%	65%	65%	65%	65%	65%	65%	65%
2021	59%	66%	63%	26%	50%	67%	63%	69%	69%	69%	69%	69%	69%	69%
2022	53%	60%	57%	24%	45%	60%	56%	70%	70%	70%	70%	70%	70%	70%
2023	39%	48%	46%	19%	36%	48%	37%	64%	64%	64%	64%	64%	64%	64%
2024	30%	36%	35%	15%	28%	37%	29%	50%	50%	50%	50%	50%	50%	50%
2025	21%	26%	25%	10%	20%	26%	20%	38%	38%	38%	38%	38%	38%	38%
2026	11%	14%	13%	6%	10%	14%	10%	27%	27%	27%	27%	27%	27%	27%
2027	6%	8%	7%	3%	6%	8%	6%	14%	14%	14%	14%	14%	14%	14%
2028	0%	0%	0%	0%	0%	0%	0%	8%	8%	8%	8%	8%	8%	8%
2029	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 75 calculates the levelized energy DRIPE benefits for efficiency measures installed in 2018 (2019 values are similar). It relies on gross loads (described in Chapter 4), the responsive load share from Table 74, and DRIPE coefficients from Figure 37.

Table 75. Seasonal energy DRIPE values for 2018 installation (levelized, 2018 $/MWh)

Type	Season	Period	ISO	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA	MA
Zone-on-Zone	Summer	Peak	33.34	2.95	3.37	0.64	7.34	2.52	4.67	7.72	4.50	16.90
		Off-Peak	22.34	2.11	2.29	0.44	5.02	1.65	3.06	5.56	3.04	11.66
	Winter	Peak	44.26	4.34	4.66	0.94	9.33	3.28	6.07	9.98	6.03	22.08
		Off-Peak	31.59	3.32	3.42	0.68	6.65	2.28	4.23	6.93	4.33	15.49
Zone-on-ROP	Summer	Peak		30.77	30.34	33.08	26.37	31.19	29.04	25.99	29.21	16.81
		Off-Peak		21.04	20.87	22.71	18.13	21.51	20.09	17.59	20.11	11.49
	Winter	Peak		40.29	39.97	43.69	35.30	41.35	38.56	34.65	38.60	22.55
		Off-Peak		28.52	28.42	31.16	25.19	29.56	27.61	24.91	27.50	16.35

Table 74 and Table 75 assume that the energy reductions continue for 10 years, until the DRIPE benefits are fully decayed. If the savings end before benefits are fully decayed, DRIPE benefits would end when the savings end.

It is difficult to directly compare the AESC 2018 results to the AESC 2015 numbers because of AESC 2015's assumptions of very short DRIPE duration (2.5 years), exclusion of hedged load, different starting date, and differences in analytical approach. Comparing the AESC 2018 peak year estimates to those from AESC 2015, zone-on-zone DRIPE estimates are $8/MWh lower to $16/MWh higher depending on season and period. Zone-on-ROP estimates are similarly varied: $1/MWh lower to $69/MWh higher. Compared to AESC 2013, our estimates are generally lower for zone-on-zone but higher for zone-on-ROP because of a single set of coefficients rather than two.

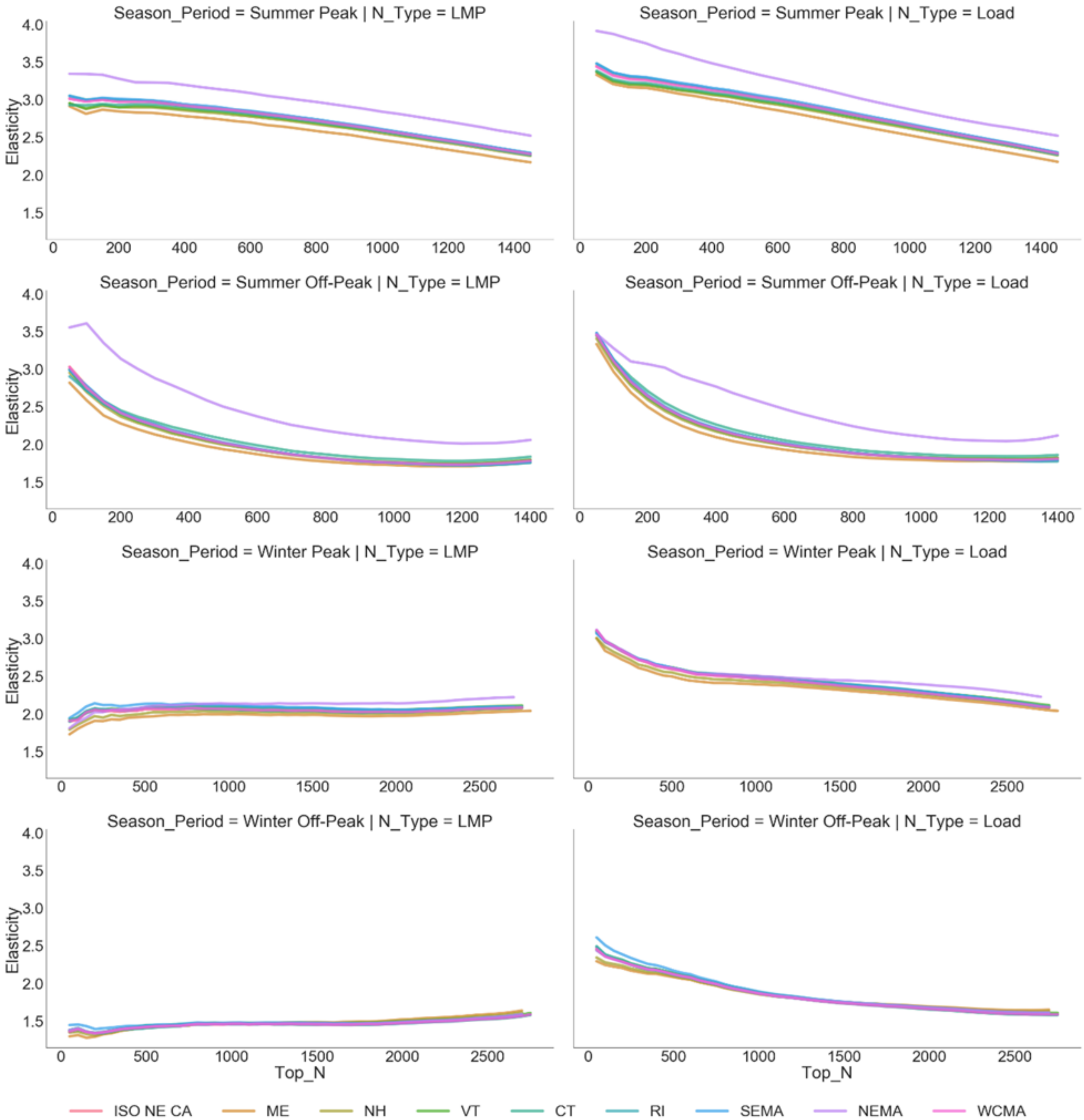
Energy peak reduction DRIPE estimates

In addition to the monthly peak and off-peak values, AESC 2018 provides estimates of the value of reducing demand in certain peak hours. Critical peak pricing or active demand response programs can take on many forms. In this analysis, AESC 2018 assumes demand response programs may target hours with either high demand or high prices. AESC 2018 estimates peak reduction energy DRIPE in an analogous manner to the monthly estimates described in the previous section. The steps for each season and zone are:

1) Aggregate the monthly results developed in the prior section into seasonal results;
2) Select the top N hours by price or load, filtering out the other observations;
3) Calculate the load-weighted elasticity for the top N hours; and
4) Use Equation 7 and Equation 8 to calculate benefits using top N hour estimates of elasticity, price, and load.

Results from this analysis are presented in Figure 38. In this chart, each row represents a season starting with spring on the top; the left column is elasticity by top N price hours, the right column is elasticity by top N load hours. Note the different ranges on the y-axis of each subplot.

Figure 38. Electric energy elasticity duration curve, by zone, season, peak type, and number of hours



In Figure 38, two trends dominate. First, elasticity values for high-load hours are larger than those for high LMP hours. High prices may occur in hours with moderate demand due to non-structural market events like transmission or generator outages. Second, the average value of load reduction in high load hours decreases as the number of hours targeted increases, while the average value of targeting high *price* hours is more consistent.

The elasticities presented in Figure 38 can be used to calculate the DRIPE of various demand response programs. Table 76 shows how an electricity program administrator could apply the electricity peak-hour DRIPE values to a demand response measure. Using the above methodology, a program targeting the top 10 load hours of the summer months in the state of Connecticut would have an elasticity of 3.4. Using 2016 load and price data and the DRIPE benefit equations (Equation 7 and Equation 8), we find that zone-on-zone energy DRIPE is worth about $129/MWh and zone-on-ROP DRIPE is worth $377/MWh.

Table 76. Example calculating DRIPE calculation for peak load hours

						DRIPE ($/MWh per MW Reduced)	
Hour #	Date	HE	ISO Demand	Zonal Demand	DA LMP	Zone-on-Zone	Zone-on-ROP
1	8/12/2016	17	16,430	6,151	$95.81	$121.43	$365.99
2	8/12/2016	16	16,161	6,128	$99.93	$128.29	$387.68
3	8/11/2016	17	15,122	6,121	$93.96	$128.78	$394.96
4	8/11/2016	18	14,790	6,114	$92.72	$129.76	$397.16
5	8/11/2016	16	14,813	6,113	$92.85	$129.73	$396.01
6	8/12/2016	18	16,009	6,053	$95.11	$121.76	$367.97
7	7/28/2016	17	14,602	6,045	$63.91	$89.58	$256.92
8	7/28/2016	16	16,479	6,035	$64.55	$80.03	$230.74
9	8/11/2016	15	18,144	6,031	$87.13	$98.06	$300.83
10	7/25/2016	16	18,532	6,028	$88.14	$97.07	$272.83
Avg DRIPE Value for top 10 Hours						**$112.45**	**$337.11**

The value of DRIPE in the top 10 hours is about triple the standard Connecticut summer peak DRIPE benefit because of the steeper slope of the supply curve during peak hours (see Figure 36). During these very high load hours, a modest reduction in demand will tend to yield significantly lower market prices.

Note that the DRIPE benefit is larger than the benefit of avoided energy consumption. Recall that DRIPE benefit is the product of the change in price associated with a reduction in demand and the amount of energy that benefits from that reduction (Equation 7). During peak periods, both terms are larger than average.

If a utility program could effectively target real-time prices instead of day-ahead prices, the value for peak-hour DRIPE would be higher still. Over the September 2014 through August 2017 study period, real-time prices averaged a third higher than day-ahead prices for the 100 hours with highest load of each year and 15 percent higher over the top 250 hours. Over the entire study period real-time prices are slightly lower than day-ahead prices. But, given the small size of the real-time market and its volatility, it is unlikely that efficiency measures could reliably target real-time prices. More pragmatically, AESC is unable to quantify the potential benefit of real-time DRIPE, because the energy forecast represents day-ahead dispatch rather than real-time. These functional and methodological limitations suggest that the use of day-ahead prices for peak-period DRIPE leads to conservative benefit estimates.

9.4. Natural Gas DRIPE

Just as reducing electric load reduces electric energy prices, reducing natural gas usage reduces demand for natural gas in producing regions and therefore reduces the market price of that natural gas supply. AESC 2018 refers to that natural gas price reduction effect as natural gas DRIPE. The wholesale cost of natural gas for natural gas consumers (the customers of the LDCs) and the cost of natural gas for electric generation in New England can each be broken into two components:

- The supply component, determined by North American demand and supply conditions on a largely annual basis, and
- Transportation costs or basis, determined by contract prices for LDCs and by the balance of regional demand and supply (mostly from pipelines) on a daily and seasonal basis.

Together, supply and basis reflect the combined benefits of reduced demand on delivered gas prices. In New England, basis benefits are significantly larger than supply benefits. This is for two reasons: first, New England demand is only a small portion of U.S. demand, so a regional change is dampened when considered on a national level; second, pipeline constraints drive delivered prices in the winter months when prices are at their highest.

The relationship between DRIPE and transportation and supply can be considered in two ways: in the volatility of each component and in the value of reduced demand. Volatility can be measured by standard deviation, a measurement that describes how data are spread out from their average value (lower values indicate less variability). Over a three-year period starting November 2014, Henry Hub's daily settlement price had a standard deviation of $0.47; basis had a standard deviation four times larger. This indicates that the price of supply is much more stable than the price of transportation. The value of reduced demand on supply and on basis (DRIPE coefficients) tell a similar story. A 1 MMBtu reduction in gas demand reduces supply prices by 1/50th as much as it reduces annual transportation prices (see Table 85).

While the basis benefits greatly exceed the supply benefits, DRIPE reduces the price and volatility of both. The remainder of this section describes and calculates these DRIPE benefits.

Wholesale natural gas supply market effects

Economic interest in the effect on natural gas prices of reduced consumption has considerable history. Conventional natural gas production, with drilling vertical wells into porous source rock, was long seen as relatively unresponsive to price changes. A conventional production meta-analysis, cited in AESC 2013, estimated that price elasticity of supply (PES) for conventional natural gas wells was between 0.33 to 1 (Wiser, 2005).[162] A PES of 0.33 indicates that a 10 percent change in price leads to a 3.3 percent change in quantity supplied to the market. These results, while still holding for conventional gas wells, no longer accurately represent the market as a whole. The relationship between natural gas supply and price was reconfigured with the rise of hydraulic fracturing and America's abundance of shale gas. AESC 2015, relying on a 2011 analysis of shale gas, assumed that gas production was relatively elastic, with a

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[162] Wiser, R., Bolinger, M., and M. St. Clair. 2005. Easing the Natural Gas Crisis: Reducing Natural Gas Prices through Increased Deployment of Renewable Energy and Energy Efficiency. LBNL-56756. http://eetd.lbl.gov/ea/ems/reports/56756.pdf.

PES estimate of 1.52.[163] These results would indicate that a 10 percent change in price would lead to a 15 percent change in quantity of natural gas supplied.

More recent analyses suggest that today's gas production is more price responsive than it was in the early 2000s but less so than assumed in the first days of the shale boom. Within these bounds, there remains substantial disagreement over the price responsiveness of natural gas supply in the United States. AESC 2018 relies on two complimentary approaches for assessing the price elasticity of natural gas:

- Meta-analysis of recent top-down and bottom-up empirical estimates
- Calculating the implied elasticity of natural gas supply in the 2017 AEO

Recent academic literature offers a split view of the price responsiveness of gas supply. On the one hand, top-down econometric models such as Hausmann & Kellogg (2015) and Newell et al (2016) suggest supply is inelastic.[164] On the other hand, bottom-up analysis like those from Rice/Baker (2011) and the University of Texas Bureau of Economic Geology (2013) indicate that supply is elastic. Results from the four studies are presented in Table 77.[165]

Comparing natural gas demand scenarios in the 2017 AEO, we find an implied PES of 0.63 over the period 2030–2050 and an implied PES of 0.57 over the period 2019–2023. The PES values are found by calculating how gas prices and quantities change in response to changes in gas demand (from the high growth scenario to the low growth scenario, and the base case to the low growth scenario).[166] While this simple calculation obscures the complex techno-economic underpinnings of the AEO modeling, it nevertheless provides a high-level assessment of the price-supply relationship. The EIA's simulation approach yields results that are more in line with those from the top-down analysis despite its nominally bottom-up process.

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[163] See AESC 2015, pages 7-22f.

[164] Hausmann & Kellogg, 2015, p12. "Welfare and Distribution Implications of Shale Gas," NBER Working Paper 21115, http://www.nber.org/papers/w21115.pdf. Newell et al., 2016, p45. "Trophy Hunting vs. Manufacturing Energy: The Price Responsiveness of Shale Gas". http://www.rff.org/files/document/file/RFF-DP-16-32.pdf.

[165] Medlock et al, 2011, p. "Shale Gas and US National Security" https://www.bakerinstitute.org/news/shale-gas-and-us-national-security/. Cf. Medlock, 2014, p24, "Natural Gas Price in Asia: What to Expect and What It Mean," https://www.bakerinstitute.org/media/files/Research/ac817540/CES-pub-NaturalGasPriceAsia-021814.pdf. Browning et al, 2013, Table 6. "Barnett study determines full field reserves, production forecast", Oil & Gas Journal. http://www.beg.utexas.edu/files/content/beg/research/shale/OGJ_SFSGAS_pt2.pdf.

[166] We exclude comparison between the high growth scenario and base case because of spurious results.

Table 77. Price responsiveness of natural gas by study

Study	% Change in Q given 1% Change in P	% Change in P given 1% Change in Q	Included in Average
AEO Implied (2017) – Long Run	0.63	1.60	TRUE
AEO Implied (2017) – Short Run	0.57	1.75	
Newell, et al (2016) – Unconventional	0.71	1.41	TRUE
Newell, et al (2016) – Conventional	0.26	3.85	
Rice/Baker (2011) – Unconventional	1.52	0.66	TRUE
Rice/Baker (2011) – Conventional	0.29	3.45	
UT BEG (2013) – Unconventional	1.37	0.73	TRUE
Hausmann & Kellogg (2015) – Unconventional	0.81	1.23	TRUE
Average of Included[167]	**1.01**	**1.13**	
Average of All	**0.77**	**1.83**	

Natural gas supply elasticity and comparison to AESC 2013 and AESC 2015

Because of the substantial variation in elasticity estimates, we took the average of five long-run analyses focusing on shale formation natural gas production. We focused on the shale gas estimates because much of the natural gas used in New England is sourced from the Marcellus and Utica shales and because shale gas is the marginal producer throughout the United States. Collectively, these studies suggest that shale gas supply is approximately unit elastic, so a 1 percent change in price leads to a 1 percent change in gas supply.

Value of natural gas commodity DRIPE

As with the electric DRIPE effects, the price reduction per MMBtu saved is a very small portion of the price per MMBtu, but each MMBtu saved reduced prices for a very large number of MMBtus. The benefit to end-use gas consumers is a significant price change per MMBtu for every billion MMBtus of reduced load. With natural gas in the $4/MMBtu range, a 1 quad change in U.S. demand would reduce prices by $0.15/MMBtu. Put differently, a 1MMBtu reduction in natural gas demand would reduce prices by $\$0.15 \times 10^{-8}$/MMBtu, a very small number.

While the decrease in price is small in absolute terms, it reduces the price of about 516 million MMBtu of annual end-use gas in New England. For the region as a whole, saving one MMBtu in 2020 reduces bills to other customers by: $(\$0.15 \times 10^{-8}$ /MMBtu$) \times (0.516 \times 10^{8}$ MMBtu$) = \$0.07$. This $0.07/MMBtu would be a small, but not trivial, addition to the avoided costs of gas in the region. The gas supply DRIPE for each New England state, and the total benefit for all New England gas end-use consumers, is shown in Table 78.

167 The average of the inverses, represented in this row, is not the same as the inverse of the averages. The inverse of the average is 0.99.

Table 78. Natural gas supply DRIPE benefit, $/MMBtu in load reduction

	Own-State DRIPE Benefit ($/MMBtu)						
	NE	CT	ME	MA	NH	RI	VT
Avg Demand (Quads)	0.52	0.14	0.03	0.25	0.04	0.05	0.01
2018	0.03	0.01	0.00	0.01	0.00	0.00	0.00
2019	0.04	0.01	0.00	0.02	0.00	0.00	0.00
2020	0.07	0.02	0.00	0.03	0.00	0.01	0.00
2021	0.08	0.02	0.00	0.04	0.01	0.01	0.00
2022	0.08	0.02	0.00	0.04	0.01	0.01	0.00
2023	0.08	0.02	0.00	0.04	0.01	0.01	0.00
2024	0.08	0.02	0.00	0.04	0.01	0.01	0.00
2025	0.08	0.02	0.00	0.04	0.01	0.01	0.00
2026	0.08	0.02	0.00	0.04	0.01	0.01	0.00
2027	0.08	0.02	0.01	0.04	0.01	0.01	0.00
2028	0.09	0.02	0.01	0.04	0.01	0.01	0.00
2029	0.09	0.02	0.01	0.04	0.01	0.01	0.00
2030	0.09	0.02	0.01	0.04	0.01	0.01	0.00
Levelized (2018–2030)	0.07	0.02	0.00	0.04	0.00	0.01	0.00

Notes: Assumes hedging of 50 percent in Year 1, 30 percent in Year 2, and 0 percent thereafter. Demand in the top row is the 2018–2030 average in quads. Total change in demand is less than 2 percent over the study period. U.S. Demand from AEO 2017, HH prices from Chapter 2. State demand is scaled from AEO 2017 New England non-electricity gas demand estimates, using the 2014–2016 ratio of state to regional demand.

Table 78 shows the benefit in each year for a reduction in gas use in that year. For example, a 1 MMBtu reduction in natural gas demand in 2021 yields a gas supply DRIPE benefit of $0.08/MMBtu for New England as a whole. We do not expect any decay in gas DRIPE; benefits should continue as long as the efficiency measure continues to reduce load. In contrast to intra-month price variation driving the electric energy DRIPE, the studies and AEO gas-price forecasts reflect the full long-term costs of gas development (at least after the first few years), not just the operation of existing wells. In addition, gas supply DRIPE is measuring the effect of demand on the marginal cost of extraction for a finite resource. If anything, lower gas usage in 2018 will leave more low-cost gas in the ground to meet demand in 2019, causing the DRIPE effect to accumulate over time. A program that saves 100 MMBtu annually from 2019 onward would have kept another 500 MMBtu in the ground by 2023, in addition to reducing 2023 demand by 100 MMBtu.

Unlike electricity DRIPE, there is no locational preference for the reduction in gas demand, so a state receives the benefit if gas demand is reduced in Massachusetts, Texas, or any other U.S. state. Table 78 depicts the value of demand reduction for each state individually. The value of interstate gas supply DRIPE is calculated by taking the New England total DRIPE value less the value from a given state. In 2020 for example, Rhode Island has a DRIPE value of $0.01/MMBtu and New England has a value of $0.07/MMBtu, so a reduction of 1 MMBtu in Rhode Island is worth $0.01/MMBtu and the value for the rest of the region is $0.06/MMBtu.

AESC 2018's gas supply DRIPE estimates are significantly lower than those found in AESC 2015, mostly due to different assumptions about the domain of price responsiveness. In line with the assessed studies, we assume price reductions are proportional to the entire U.S. market, rather than just the Utica and Marcellus shale producing region—this dampens the effect of a local reduction on prices.[168] DRIPE benefits are also lower than previously assumed due to lower natural gas price forecast. These two factors are modestly offset by our assessment that natural gas supply is less price sensitive than assumed in AESC 2015 (AESC 2018 PES = 1.01 compared to 1.52 in AESC 2015). These three changes lead to state-on-state DRIPE benefits which are 70 percent lower than those found in AESC 2015.

Table 79. Comparing levelized natural gas supply DRIPE estimates from 2018 AESC with 2015 AESC (2018 $/MMBtu)

	CT	MA	ME	NH	RI	VT	NE
AESC 2015	0.060	0.137	0.021	0.012	0.019	0.005	0.253
AESC 2018	0.020	0.035	0.005	0.005	0.007	0.001	0.073
Difference ($)	-0.04	-0.10	-0.02	-0.01	-0.01	0.00	-0.18
Difference (%)	-67%	-74%	-79%	-59%	-62%	-81%	-71%

Wholesale gas transportation market effects

In addition to its effect on prices in the supply areas, reductions in annual gas use will reduce the basis, or price differential between the wholesale market price of gas in New England and the prices in the supply areas. While basis DRIPE is assumed nil for natural gas consumers because of LDC hedging, it is a component of cross-DRIPE (discussed in a subsequent section).

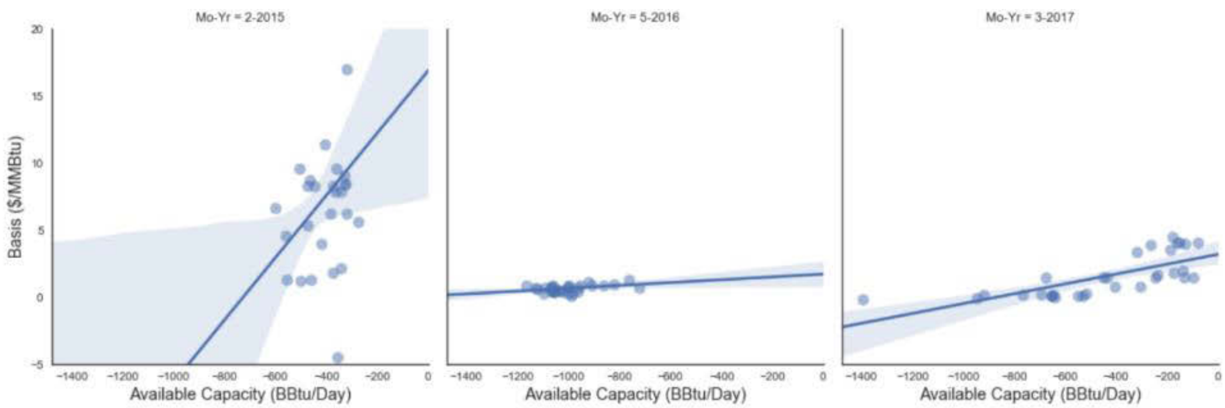
The basis component of the wholesale market price of gas in New England has risen rapidly in the last year or so, as discussed in the above section on natural gas price forecasting. The majority of that basis is attributable to constraints on gas delivery capacity into New England from the Mid-Atlantic region. As a result, our analysis focused on the basis, or price differential, between the Texas Eastern Transmission Zone M-3 (in Pennsylvania and New Jersey) and the Algonquin Gas Transmission citygates in Connecticut, Rhode Island, and eastern Massachusetts.

Using three years of data (November 2014 to October 2017), AESC 2018 estimated the relationship between pipeline availability and basis prices. AESC 2018 measures availability as daily demand less maximum capacity, rather than absolute quantities, because the Algonquin pipeline was modestly expanded before the 2016/17 winter, increasing supply. No data appears to be available on daily (or even weekly) consumption by state or region. Consequently, we use as our measure of load the daily day-ahead scheduled net deliveries in New England on the AGT and TGP pipelines, minus deliveries from the Maritimes & Northeast (MNE) and Iroquois pipeline, and from the Distrigas LNG facility at Everett.

[168] In 2017, The Utica and Marcellus shales produced about 8 quads of natural gas, about 30 percent of the total U.S. production of 28 quads. See https://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf.

Estimating basis DRIPE is difficult and somewhat uncertain because of system time dependences, weather dependences, market features, and non-linearities that fall outside the scope of this analysis. On a macro level, some winters are milder or harsher than others, resulting in varying overall pipeline utilization. On a day-to-day basis, a sustained cold snap may result in basis blowout due to the exhaustion of local gas storage while a shorter one might be ameliorated with local supplies. Regulatory interventions such as ISO New England's winter reliability program have encouraged gas-oil substitution, reducing some dependence on pipeline supplies. Figure 39 depicts the trouble with estimating basis DRIPE by comparing pipeline capacity with basis in three different months: February 2015, May 2016, and March 2017.

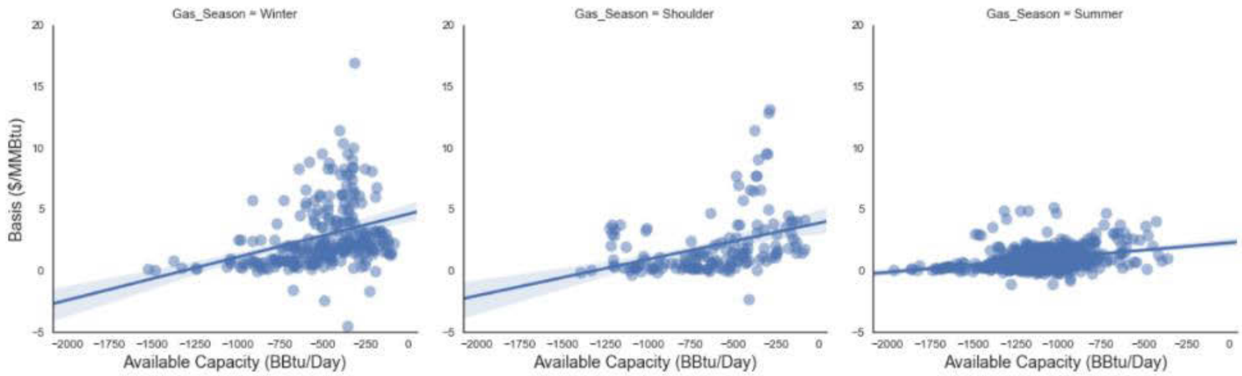
Figure 39. Relationship between natural gas basis (Algonquin- TETCO M3) and pipeline available capacity



Months like May 2016 have a clear relationship between capacity and basis, and they exhibit a modest slope ($1.05/MMBtu per million MMBtu reduced); March 2017 has higher coefficient ($3.67/MMBtu per million MMBtu reduced) but a similarly clear relationship. February 2015 had very tight supply but an unclear relationship between price and supply—its coefficient is very high ($23.23/MMBtu per million MMBtu reduced) but it had a poor modeled fit (R^2 = 0.11).

Aggregating daily data into seasons provides similar but slightly more muted results. Figure 40 plots basis vs capacity for the seven summer months, three winter months, and November and March shoulder months.

Figure 40. Seasonal relationship between basis and pipeline capacity (11/2014 – 10/2017)



These aggregate runs depict somewhat lower coefficients on average than the average monthly results and are more dependent on the assumption of weather representativeness. The preference for seasonal averages as opposed to monthly derives from the fact that basis coefficients have many intra-month and intra-season dependencies (e.g. weather / cold snaps, storage levels, LDC hedging strategies and capacity releases, etc.). More granular coefficients could be developed for programs targeting very specific conditions—for example, a demand response program targeting only polar vortex style conditions—but such analysis is highly dependent on program goals and falls outside the scope of this work.

AESC 2108 ran the basis analysis for four different periods in three ways: (1) monthly regressions aggregated into seasonal averages, (2) multiyear seasonal regressions which combine all data from the same season into a single dataset, and (3) weather-adjusted estimate for the three-month winter period (because none of the past three years are representative of historical norms).[169] Table 80 depicts the coefficient values estimated using the three techniques as well as the values we used.

[169] We rely on normal distribution shortcut discretization methods to create a weather-adjusted estimate. These methods seek to approximate a normal distribution by weighting outcomes of various likelihoods. The Extended Swanson-Megill (ESM) weights the 10th (P10), 50th (P50), and 90th (P90) percentiles of a normal distribution by 30 percent, 40 percent, and 30 percent respectively. Regression coefficients from months that had HDDs similar to the 10th, 50th and 90th percentile of winter months were weighted using the McNamee-Celona Shortcut values of 0.25, 0.5, and 0.25.

Table 80. Natural gas basis DRIPE coefficients (2018 $/MMBtu per 1,000,000 MMBtu/day saved)

Period		Prior Estimates			AESC 2018 Estimation Method			
Season	Months	AESC 2015 High	AESC 2015 Low	AESC 2013	Combined Regressions	Averaged Monthly Regressions	Weather Adjusted Monthly	AESC 2018
Summer (7 Months)	Apr–Oct			0.4	1.20	1.09		1.09
Winter (5 Months)	Nov–Mar			8.9	3.40	4.98		4.98
Winter (3 Months)	Dec–Feb	7.57	0.57	16	3.51	5.26	5.77	5.77
Shoulder (2 Months)	Nov, Mar			8	2.96	4.48		4.48

Note: AESC 2013 uses a 3-month winter and 3-month shoulder, not the 2-month industry period; AESC 2015 uses an elasticity approach which is not directly comparable. High Value is for Winter 2013/14 where basis averaged $11–$30/MMBtu; Low case represents estimate for winter 2018/19 with forecast basis of $2/MMBtu.

The value of basis DRIPE ranges from approximately $1/MMBtu per million MMBtu reduction in the summer to more than $5/MMBtu per million MMBtu reduction in mid-winter. We used higher-end estimates for two reasons: first, these fall more in line with AESC 2013 and AESC 2015 estimates; second, our dataset does not include periods of "basis blowout" like the polar vortex of early 2014 or the holiday's cold snap of December 2017–January 2018. Periods with higher basis but the same pipeline tightness would lead to steeper slopes. Summer basis is higher in AESC 2018 because we include data from April through October, rather than just June through August, and this longer season includes some shoulder periods when modest space heating load picks up.

In the future, AESC 2018 assumes that sensitivity of winter basis to gas load will match the weather-adjusted slope from the winters of 2014/15, 2015/16, and 2016/17. AESC 2018 do not expect a material reduction in basis over the short or medium term. Early evidence from the winter of 2017/18 indicates that basis blowout is still possible despite improved electric/gas scheduling and modest pipeline capacity expansion. In the long run, basis prices are backstopped by substitution effects for pipeline/LNG deliveries and of gas/oil fuel substitution. Basis could be reduced if a substantial pipeline capacity were added in New England or if demand were substantially reduced, but we do not expect this for the foreseeable future.

9.5. Oil Supply DRIPE

Reducing demand for petroleum and refined products should lead to a reduction in oil prices. Oil demand may be lessened by further electrifying the transportation sector (oil-electricity substitution effects) or by reducing electricity demand during high load winter periods when oil is on the margin (oil-gas substitution). This reduction in oil prices induced by a change in oil demand is termed oil DRIPE and is new for AESC 2018.

Oil's global dimension makes modeling oil DRIPE more uncertain than the analysis of natural gas DRIPE. The AESC 2018 analysis relied on analysis of oil supply fundamentals which, in turn, does not consider the impact of oil supply disruptions or other sources of short-term volatility in oil price. We were unable to use the same approach to calculate oil supply price responsiveness that we did for natural gas due to a lack of data availability.[170] We conduct a relatively high-level model of oil DRIPE in four steps:

1) Estimate price/supply relationship from crude oil breakeven analyses.
2) Calculate the change in price for a reduction in the demand for crude oil.
3) Calculate crude oil DRIPE value.
4) Calculate refined product DRIPE values using the relatively stable crude-to-refined-product price ratios from AEO 2017 for Years 2022–2030. For example, a gallon of diesel sells for a 30 percent premium compared to a gallon of crude (residual a little higher, gasoline a little lower), so we estimate the value of diesel DRIPE is 30 percent larger than that of crude oil.

This analysis assumes that oil supply drives the price of refined products and that a reduction in the demand of any petroleum product impacts the price of all other crude products. In reality, there may not be a one-to-one price benefit for reductions in gasoline on fuel oils (or other refined liquids). This simplifying assumption is reasonable given the small magnitude of oil DRIPE effects and the high-level analysis undertaken.

Oil play breakeven analysis models the price at which a given geological formation is revenue neutral (a specific oil field or formation is known in the industry as a “play”). Different plays have different breakeven points, and when considered in aggregate, a supply curve is produced showing the prices at which various sources of new supply would enter the market (this curve is analogous to an electric market’s power plant offer stack).

Using breakeven supply curves, we can assess the average relationship between price and supply for the marginal barrel of oil. Table 81 presents elasticities from five different breakeven analyses—two of which offer a supply curve with a very steep right tail, which we estimate separately. The Wood Mackenzie supply curve, for example, indicates that an additional million barrels per day of oil supply would increase breakeven price by about $3/barrel. In different units, it indicates that a 1.0 percent increase in cumulative oil production in this region would increase costs by 0.36 percent.

[170] The NEMS model used in EIA’s AEO appears to calculate oil prices on a global, or pseudo-global, basis but demand changes on a local basis – resulting in coefficients 5x to 10x larger than found using the breakeven analyses. The AEO does not provide global oil supply by side-case.

Table 81. Percent change in crude oil price for a 1.0 percent change in global demand

Forecast	Curve Segment	Date	Elasticity	Source[171]
Wood Mackenzie	Only	2016	0.36	(A)
Rystad Energy	Only	2015	1.39	(B)
IEA	Only	2013	2.00	(C)
Goldman Sachs	Low	2012	0.47	(D)
Goldman Sachs	High	2012	2.66	(D)
BP/PIRA	Low	2015	0.88	(E)
BP/PIRA	High	2015	3.60	(E)
Average			**1.62**	
Average (Low, Only)			**1.02**	

A simple average of the forecasts yields an elasticity of 1.62 (1.02 if the two high slope portions of the supply curve are excluded). Given the uncertain nature of this analysis, AESC 2018 models oil supply as unit elastic in the relevant region study, so a 1 percent change in demand would yield a 1 percent change in price. Critically, demand in this context is *global demand* (currently 98 million barrels/day, of which the United States consumes about one-fifth).[172] This estimate is similar to our estimate of elasticity of supply for natural gas—something we would expect given the similarities between the two hydrocarbons, their disposition, and their extraction.

The assumption of unit elasticity may overstate price effects because estimates of shale resources have increased in the past years and estimates of shale extraction costs have fallen—both effects reduce the slope of the supply curve, and its corresponding elasticity.

Value of oil DRIPE

As with the electric and natural gas DRIPE effects, the price reduction per MMBtu of oil saved is a very tiny portion of the price per MMBtu, but each MMBtu saved reduced prices for a very large number of MMBtus. Given the modest size of New England oil demand in comparison to the entire global market (about 0.7 percent of worldwide consumption), the overall value of DRIPE remains modest.

New England consumes approximately 1.4 quads of petroleum products yearly, so a 1 MMBtu reduction in demand yields an average regional benefit of about $0.08. The value for each state, presented in

171 Sources for Table 81 are (A) https://www.woodmac.com/news/editorial/pre-fid-oil-projects-commercial/, (B) https://www.rystadenergy.com/NewsEvents/PressReleases/global-liquids-supply-cost-curve, (C) https://www.financialsense.com/contributors/joseph-dancy/iea-shale-mirage-future-crude-oil-supply-crunch, (D) http://crudeoilpeak.info/oil-price-analysis, and (E) https://www.bp.com/content/dam/bp/pdf/speeches/2015/new-economics-of-oil-spencer-dale.pdf.

172 For more information, see https://www.iea.org/oilmarketreport/omrpublic/.

Table 82, are proportionally smaller, ranging from about $0.01/MMBtu to $0.03/MMBtu per 1 MMBtu reduction.[173] As with natural gas supply DRIPE, oil DRIPE are not decayed.

Table 82. Oil DRIPE by state, 2018–2028 ($/MMBtu per MMBtu reduced)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE						
Year	NE	CT	MA	ME	NH	RI	VT	NE	CT	MA	ME	NH	RI	VT
2018	0.07	0.02	0.02	0.01	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2019	0.07	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.06	0.07	0.07	0.07
2020	0.08	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2021	0.08	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.08
2022	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2023	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2024	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2025	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2026	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2027	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2028	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2029	0.08	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2030+	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
levelized (2018–2030)	0.08	0.02	0.03	0.01	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.08

As with natural gas supply DRIPE, oil DRIPE are not decayed. Because oil DRIPE is not decayed, the values in the preceding table reflect the actual value of a demand reduction in each year (e.g. a demand reduction in 2018 is worth $0.07/MMBtu on a regional level and a reduction in 2025 is worth $0.09/MMBtu).

Oil DRIPE benefits for each state are approximately zero for all years irrespective of oil price (range: $49–$89/bbl), global demand (range: 98–104 million barrels per day), or regional consumption (range: 0.59–0.69 million barrels per day). These values are low because of the relatively modest amounts of demand in New England states compared to the size of the global oil market.

To convert from the crude oil DRIPE values to those of specific refined commodities, multiply the values in Table 82 by the refined-price to crude-price ratio found in Table 83. For example, the levelized value of gasoline DRIPE across New England is worth $0.10/MMBtu reduced ($0.08/MMBtu x 1.25).

[173] The United States consumes about 37 quads of petroleum products annually, compared with 1.4 quads consumed in New England. The value of a 1 MMBtu reduction in oil demand anywhere within the United States has a US-wide DRIPE value of $2.25/MMBtu.

Table 83. AEO 2017 prices of crude oil and refined petroleum products[174]

Product	2022–2030 Avg Price (2016 $/Gal.)	Refined-to-WTI Ratio
WTI Crude Oil	1.93	
Gasoline	2.42	1.25
Diesel	2.55	1.32
Residual	2.60	1.35

9.6. Cross-Fuel Market Price Effects

The preceding sections calculated direct DRIPE effects where a reduction in demand for a given commodity reduced prices for that same commodity. DRIPE benefits also accrue indirectly through cross-DRIPE, which measures the impact that a reduction in one commodity has on a different commodity. We assess three kinds of cross-DRIPE:

1. **Gas-to-electric (G-E) cross-DRIPE** measures the benefits to electricity consumers that result from a reduction in gas demand. Gas-fired generators set electric market prices in most hours, so reducing gas prices should reduce electricity prices.
2. **Electric-to-gas (E-G) cross-DRIPE** measures the benefits to gas consumers from a reduction in electricity demand. Electric power accounts for 1/3 of the region's gas demand, so reducing electricity demand should reduce gas prices.
3. **Electric-to-gas-to-electric (E-G-E) cross-DRIPE** combines the first two benefits. Reductions in electricity demand should reduce gas prices (E-G cross-DRIPE) which should, in turn reduce electricity prices (G-E cross-DRIPE). E-G-E cross-DRIPE is separate from direct electric energy DRIPE and does not double-count any benefits. Reductions in electricity demand yield two benefits. First, lower demand levels will tend to switch the marginal unit to something lower cost, yielding a market price reduction through plant substitution. Second, lower electricity demand levels reduce the demand for, and price of, natural gas. Thus, natural gas power plants, which set prices in most hours, burn less expensive gas than they would have otherwise. Own-fuel energy DRIPE captures the first benefit, E-G-E cross DRIPE captures the second benefit. In our energy DRIPE calculations, we explicitly control for natural gas prices, which means own-fuel energy DRIPE is only measuring the benefits of switching from a less efficient plant to a more efficient plant. For E-G-E DRIPE, we hold the powerplant constant, and reflect how a change in gas prices changes electric prices.

Table 84 summarizes the methods used for estimating the various DRIPE effects that flow through various aspects of gas prices. We compute E-G DRIPE using a method analogous to that used in Section 5.3 for estimating the own-price natural gas supply DRIPE. In E-G cross-DRIPE, basis costs are assumed to be fully hedged for LDC customers. G-E cross-DRIPE is computed by reflecting how a change in electricity

[174] EIA AEO 2017 Table: "Components of Selected Petroleum Product Prices" https://www.eia.gov/outlooks/aeo/data/browser/#/?id=70-AEO2017&region=1-1&cases=ref2017~ref_no_cpp~highmacro~lowmacro&start=2015&end=2050&f=A&sourcekey=0.

demand affects gas supply (see the above section on the value of natural gas commodity DRIPE) and gas basis effects (see the above section on wholesale gas transportation market effects). E-G-E DRIPE combines the first two effects. Unlike AESC 2015, E-G-E DRIPE now includes both gas supply and gas basis components because the energy DRIPE calculations explicitly control for natural gas.

Table 84. Summary of gas-related DRIPE effects

Gas price affected		Conservation of energy	
		Gas	Electricity
To LDC gas consumers	Supply	Own-DRIPE (a)	Cross-DRIPE (a)
	Basis	Hedged (b)	Hedged (b)
To gas-fired electric generation	Supply	Cross-DRIPE (c)	Cross-DRIPE (a)
	Basis	Cross-DRIPE (a)	Cross-DRIPE (a)

Note: (a) based on gas supply curve analysis from "Natural Gas DRIPE" section, above; (b) no effect; (c) basis supply curve analysis

Effect of gas prices on market electric energy price (Gas-to-electric cross-DRIPE)

The value of Gas-to-Electric cross-DRIPE depends on the own-price gas DRIPE coefficients derived in Section 9.4, the efficiency of gas fired generators, and how often these generators set the market energy price.

The ISO New England marginal energy price per MWh in 2016 averaged about 7.1 times the price of gas per MMBtu at the Algonquin citygates, representing an effective marginal heat rate of 7,100 Btu/kWh (ISO New England day-ahead LMP averaged $31.32/MWh and Algonquin Citygate averaged $4.49/TCF). The actual heat rate in the hours in which gas is at the margin may be slightly different from this value, but the ISO does not provide data in sufficient detail to determine whether the average marginal gas heat rate is higher or lower than the implied average heat rate.[175]

Natural gas-fired generators set the market energy price in 74 percent of hours between 2012 and 2016. [176] Natural gas must also strongly affect energy prices in the 13 percent of hours for which pumped storage sets the market price, since gas is likely to fuel most of the energy used for pumping and most of the energy that pumped-storage generation displaces.

Gas to Electric cross-DRIPE depends on the price of natural gas supply and in natural gas transportation (basis). Supply will be considered first, then basis. Assuming that natural gas sets the marginal price

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[175] If the marginal energy supply when gas was not marginal were always less expensive than gas (e.g., some coal), the energy price (and hence the implicit heat rate) when gas is running would be higher than average. Conversely, if the marginal energy supply when gas was not marginal were always more expensive than gas (e.g., some coal and most oil), the energy price (and hence the implicit heat rate) when gas is running would be lower than average. It is not clear how these two factors balance out.

[176] Source: Figure 4-7; 2017-12-12 EAG Draft 2016 Generator Air Emissions Report. https://www.iso-ne.com/system-planning/system-plans-studies/emissions.

(directly or indirectly) in 85 percent of hours, at an average heat rate of 7,100 Btu/kWh, a $1/MMBtu change in the price of gas would change the price of electricity by about $6/MWh:

$$Price\ Effect_{NG\ on\ Elec} = \Delta Price_{Gas} \times Heatrate \times Share\ of\ Marginal\ Supply\ NG$$

$$Price\ Effect_{NG\ on\ Elec} = \$1/MMBtu \times 7.1\ MMBtu/MWh \times 0.85$$

$$Price\ Effect_{NG\ on\ Elec} = \$6/MWh\ per\ \$1/MMBtu\ reduction$$

The same analysis yields a Quantity Effect, which measures the physical relationship between electricity production and gas consumption:

$$Quantity\ Effect_{Elec\ on\ NG} = 6/MMBtu\ per\ 1/MWh\ reduction$$

The Quantity Effect indicates that 1 MWh of electricity generation requires 6 MMBtu of fuel on average, so each MWh of electricity saved should reduce gas demand by 6 MMBtu. Note that Price Effect and Quantity Effect are of the same magnitude but with inverse units.

The DRIPE effect on annual average wholesale electric energy prices in New England due to a reduction in annual average gas well-head prices from a one MMBtu reduction in annual gas use would be:

$$DRIPE\ Coef_{gas\ on\ elec} = DRIPE\ Coef_{gas\ supply} \times Quantity\ Effect_{Elec\ on\ NG}$$

$$DRIPE\ Coef_{gas\ on\ elec} = \$0.15 \times 10^{-8}/MMBtu \times 6\ MMBtu/MWh$$

$$DRIPE\ Coef_{gas\ on\ elec} = \$0.89 \times 10^{-8}/MWh\ per\ MMBtu\ saved$$

The cross-price DRIPE effect in each state is the product of the cross-DRIPE coefficient and the projected portion of annual electric energy consumption in each state that is not subject to some form of price hedge:[177]

$$Gas\ on\ Electric\ DRIPE_{Zone} = DRIPE\ Coef_{gas\ on\ elec} \times Electricity\ Demand_{Zone}$$

Similar to gas commodity DRIPE effects on electricity prices, a reduction in gas demand leads to lower pipeline transportation costs. Lower basis reduces the overall price of natural gas, which results in lower cost electricity. For example, one MMBtu of reduced gas use from space-heating gas conversion would reduce electricity prices by:

$$DRIPE\ Coef_{basis\ on\ elec} = DRIPE\ Coef_{Basis,5Mo\ Winter} \times Quantity\ Effect_{Elec\ on\ NG}$$

The cross-price DRIPE effect from basis in each state is the per-unit change in electricity price times the total amount of unhedged electricity:

[177] Since generation everywhere in ISO New England serves load throughout New England, the cross-price effect on electric consumers in a state is not dependent on the amount of gas burned for electric generation in that state.

$$Basis\ on\ Electric\ DRIPE_{Zone} = DRIPE\ Coef_{basis\ on\ elec} \times Electricity\ Demand_{Zone}$$

The effect of baseload reductions is calculated analogously, except for a smaller coefficient that accounts for annual basis effects. The Gas-to-Electric cross-DRIPE effect is subject to decay similar to direct electric DRIPE, except that:

1. There is no RPS effect;
2. The existing-generation effect is reduced by one-third, reflecting the tendency for lower gas prices to improve the economics of gas-fired plants, even though the lower electric energy prices would reduce the economics of all plants; and
3. The new-generation effect is increased by 50 percent, reflecting the tendency for lower gas prices to discourage investment in combined-cycle plants, rather than combustion turbines, in addition to the effect of lower electric energy prices.

Table 85 summarizes the gas-on-electric cross-fuel basis DRIPE coefficients, stated in dollars per TWh (million MWh) per MMBtu saved, based on the basis DRIPE coefficients, the supply DRIPE coefficient, and the decay factors.

Table 85. Gas-on-electric cross-fuel DRIPE coefficients ($/TWh per MMBtu gas saved)

		Electric		Gas			Basis
		Summer	Winter	Summer	Winter	Annual	Decay
Undecayed Coefficients ($/TWh per MMBtu of Gas Saved)	Supply	0.0009	0.0009	0.0009	0.0009	0.0009	
	Basis	0.0543	0.0885	0.0308	0.1992	0.0450	
	Total	0.0552	0.0894	0.0317	0.2000	0.0459	
Decayed Coefficients	2018	0.0544	0.0883	0.0313	0.1974	0.0453	1.3%
	2019	0.0529	0.0858	0.0304	0.1919	0.0440	4.1%
	2020	0.0514	0.0834	0.0296	0.1864	0.0428	6.8%
	2021	0.0463	0.0750	0.0266	0.1675	0.0385	16.3%
	2022	0.0414	0.0670	0.0239	0.1495	0.0345	25.4%
	2023	0.0298	0.0480	0.0173	0.1069	0.0248	46.8%
	2024	0.0188	0.0301	0.0111	0.0667	0.0158	67.0%
	2025	0.0139	0.0222	0.0083	0.0487	0.0117	76.0%
	2026	0.0093	0.0146	0.0057	0.0318	0.0079	84.5%
	2027	0.0050	0.0075	0.0032	0.0158	0.0043	92.5%
	2028	0.0009	0.0009	0.0009	0.0009	0.0009	100.0%

Table 86 summarizes the own-state and ISO-wide cross-fuel DRIPE values for 2018 gas efficiency installations based upon the coefficients in Table 85 and the unhedged energy in each period. For the annual effects, we rely on the annual coefficient; for space-heating effects, we rely on gas winter period coefficients.

Table 86. Gas-to-electric cross-fuel heating DRIPE, 2018 gas efficiency installations

	Annual ($/MMBtu)									
Year	**ISO NE**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**NEMA**	**WCMA**	**MA**
2018	2.46	0.24	0.25	0.05	0.52	0.18	0.34	0.54	0.34	1.22
2019	3.88	0.38	0.39	0.08	0.82	0.28	0.53	0.85	0.54	1.93
2020	4.27	0.42	0.44	0.09	0.90	0.30	0.59	0.94	0.60	2.13
2021	4.29	0.42	0.44	0.09	0.89	0.30	0.59	0.95	0.60	2.15
2022	3.88	0.38	0.40	0.08	0.80	0.27	0.54	0.86	0.55	1.94
2023	2.58	0.28	0.29	0.06	0.58	0.20	0.33	0.52	0.33	1.17
2024	1.65	0.18	0.18	0.04	0.37	0.13	0.21	0.33	0.21	0.75
2025	1.23	0.13	0.14	0.03	0.28	0.10	0.15	0.24	0.16	0.55
2026	0.83	0.09	0.09	0.02	0.19	0.07	0.10	0.16	0.10	0.37
2027	0.45	0.05	0.05	0.01	0.10	0.04	0.06	0.09	0.06	0.20
2028	0.10	0.01	0.01	0.00	0.02	0.01	0.01	0.02	0.01	0.04
2029	0.10	0.01	0.01	0.00	0.02	0.01	0.01	0.02	0.01	0.04
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
levelized	2.59	0.26	0.27	0.05	0.55	0.19	0.35	0.56	0.36	1.26

	Winter/Space-Heating ($/MMBtu)									
Year	**ISO NE**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**NEMA**	**WCMA**	**MA**
2018	4.58	0.44	0.47	0.09	0.97	0.32	0.61	1.02	0.64	2.27
2019	7.21	0.70	0.74	0.15	1.52	0.51	0.97	1.60	1.01	3.58
2020	7.94	0.77	0.81	0.16	1.67	0.56	1.07	1.77	1.12	3.95
2021	7.94	0.78	0.82	0.16	1.64	0.55	1.07	1.77	1.12	3.97
2022	7.18	0.70	0.74	0.15	1.49	0.50	0.97	1.60	1.02	3.59
2023	4.75	0.51	0.53	0.11	1.07	0.36	0.58	0.96	0.61	2.15
2024	2.99	0.32	0.33	0.07	0.67	0.23	0.37	0.61	0.38	1.36
2025	2.19	0.24	0.25	0.05	0.50	0.17	0.27	0.44	0.28	0.98
2026	1.43	0.16	0.16	0.03	0.33	0.11	0.17	0.28	0.18	0.63
2027	0.72	0.08	0.08	0.02	0.16	0.06	0.09	0.14	0.09	0.32
2028	0.04	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01	0.02
2029	0.04	0.00	0.00	0.00	0.01	0.00	0.01	0.01	0.01	0.02
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
levelized	4.77	0.48	0.50	0.10	1.02	0.34	0.63	1.04	0.66	2.32

Table 86 indicates that the annual ISO New England-wide value of G-E cross-DRIPE for 2018 is $2.46/MMBtu. The space-heating value is approximately double that because of the higher basis values in the winter months. Since generation everywhere in ISO New England serves load throughout New England, the cross-price effect on electric consumers in a state is not dependent on the amount of gas burned for electric generation in that state.

The zone-on-ROP benefit equals the difference between ISO-wide benefit and the zonal benefit. For 2018, Connecticut's annual zone-on-zone cross-DRIPE is worth \$0.52/MMBtu and the Connecticut-on-ROP benefit is worth \$1.94/MMBtu (which, added together, yields the ISO-wide value of \$2.46/MMBtu). Other zone-on-ROP values can be computed in the same way.

Table 87 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2015 and AESC 2018. In general, AESC 2018 annual results are lower than those from AESC 2015 due to modestly lower basis DRIPE estimates and slightly lower implied heat rates in ISO New England in recent years. The winter results are higher due to the longer decay period found in AESC 2018.

Table 87. Comparison of gas-on-electric cross-DRIPE benefits from 2018 AESC and 2015 AESC

Period and AESC Version	ISO NE	ME	NH	VT	CT	RI	MA
Annual							
AESC 2015 (Levelized)	3.27	0.29	0.31	0.15	0.82	0.20	1.51
AESC 2018 (Levelized)	2.59	0.26	0.27	0.05	0.55	0.19	1.26
Difference (\$)	-0.68	-0.02	-0.03	-0.09	-0.27	-0.01	-0.25
Difference (%)	79%	91%	89%	36%	67%	94%	84%
Gas Winter / Space Heating							
AESC 2015 (Levelized)	2.91	0.26	0.27	0.13	0.73	0.18	1.34
AESC 2018 (Levelized)	4.77	0.48	0.50	0.10	1.02	0.34	2.32
Difference (\$)	1.86	0.22	0.23	-0.03	0.29	0.16	0.98
Difference (%)	164%	186%	184%	76%	140%	194%	173%

Effect of electricity prices on natural gas supply prices (electric-to-gas cross-DRIPE)

Electric-to-Gas (E-G) cross-DRIPE measures the benefits to gas consumers from a reduction in electricity demand. Electric power accounts for approximately one-third of the region's gas demand, so reducing electricity demand should reduce gas prices, all else equal.

In the previous section, we estimated the cross-DRIPE gas-electric Quantity Effect, which indicates that 1 MWh of electricity requires 6 MMBtu on average, so each MWh of electricity saved should reduce gas demand by 6 MMBtu. The Quantity Effect lets us calculate E-G DRIPE by scaling the own-price gas supply DRIPE coefficient by 6 MMBtu/MWh:

$$DRIPE\ Coef_{Electric\ on\ Gas\ Supply} = Quantity\ Effect_{Elec\ on\ NG} \times DRIPE\ Coef_{NG\ supply\ on\ elec}$$

$$DRIPE\ Coef_{Electric\ on\ Gas\ Supply} = 6MMBtu/MWh \times \$0.15 \times 10^{-8}/MMBtu$$

$$DRIPE\ Coef_{Electric\ on\ Gas\ Supply} = \$0.89 \times 10^{-8}/MMBtu\ per\ MWh\ saved$$

Multiplying the E-G cross-DRIPE coefficient by zonal gas demand yields the zonal cross-DRIPE value.

$$EG\ DRIPE_{Zone} = DRIPE\ Coef_{Electric\ on\ Gas\ Supply} \times Gas\ Demand_{Zone}$$

Table 88 shows the results of multiplying the estimated supply price reduction per MWh of electric conservation by the end-use gas consumption in each state and the region to estimate the electric-on-gas supply DRIPE effect. As with regular gas supply DRIPE, gas demand is effectively flat, but commodity price changes lead to slight increases in cross-DRIPE benefits over the study period. In Table 88, we assume 50 percent hedging in Year 1 and 20 percent hedging in Year 2.

Table 88. Annual gas price benefit per MWh reduced by state

	E-G Cross DRIPE, Zone-on-Zone, $/MWh)						
Year	**CT**	**MA**	**ME**	**NH**	**RI**	**VT**	**NE**
2018	0.063	0.111	0.014	0.016	0.023	0.003	0.229
2019	0.100	0.176	0.023	0.025	0.037	0.005	0.365
2020	0.124	0.219	0.028	0.031	0.045	0.006	0.453
2021	0.124	0.219	0.028	0.031	0.045	0.006	0.452
2022	0.125	0.220	0.028	0.031	0.046	0.006	0.455
2023	0.125	0.221	0.028	0.031	0.046	0.006	0.457
2024	0.126	0.222	0.028	0.031	0.046	0.006	0.459
2025	0.126	0.223	0.029	0.031	0.046	0.006	0.461
2026	0.126	0.223	0.029	0.031	0.046	0.006	0.462
2027	0.127	0.224	0.029	0.032	0.046	0.006	0.463
2028	0.127	0.224	0.029	0.032	0.046	0.006	0.463
2029	0.127	0.224	0.029	0.032	0.046	0.006	0.464
2030	0.127	0.224	0.029	0.032	0.046	0.006	0.464

The zone-on-ROP value for electric-on-gas cross-DRIPE can be computed by taking the difference of the regional DRIPE benefit and a specific zone. The values in Table 88 are not expected to decay over the study period, leading to higher estimates than those in AESC 2015. These estimates are comparable to AESC 2013.

Effect of electric conservation on electric prices through gas supply prices (E-G-E Cross DRIPE)

A reduction in electricity prices will reduce the price of natural gas; this reduction in natural gas prices will, in turn, reduce the price of electric energy. The magnitude of this reduction depends both on supply and on basis. E-G-E cross-DRIPE is separate from and offers benefits in addition to electric energy DRIPE.

The approach to compute E-G-E DRIPE is similar to computing the previous forms of cross-DRIPE except that it generates values that depend on zone and season, because gas prices vary with season. Conceptually we apply the gas consumption to electricity production relationship (6MMBtu = 1 MWh) to the gas-on-electric cross-fuel DRIPE coefficients to estimate E-G-E DRIPE:

$$EGE\ DRIPE\ Coef_{Zone} = \ DRIPE\ Coef_{gas\ on\ electric} \times Price\ Effect_{NG\ on\ Elec}$$

The gas-on-electric DRIPE coefficients depends on season and are analogous those found in Table 85 but are offered for both gas and electricity specific periods (electricity periods are better aligned for electric efficiency program screening, but gas periods show the effects of gas basis more clearly).

EGE DRIPE coefficient values are computed in Table 89. Because the gas market settles daily rather than hourly, there is no difference in peak/off-peak period coefficients (there are differences in final DRIPE benefits due to different amounts of energy consumed in the different time periods).

Table 89. Electric-on-gas-on-electric cross-fuel DRIPE coefficients (2018 $/TWh per MWh saved)

		Electric			Basis
		Summer	Winter	Annual	Decay
Undecayed Coefficients ($/TWh per MWh/Period Reduced)	G-E Coef.	0.0552	0.0894	0.0459	
	Gas/Elec Price Effect	6.0350	6.0350	6.0350	
	E-G-E Coef.	0.3328	0.5397	0.2768	
Decayed Coefficients	2018	0.3285	0.5326	0.2733	1.3%
	2019	0.3194	0.5178	0.2657	4.1%
	2020	0.3104	0.5031	0.2583	6.8%
	2021	0.2794	0.4524	0.2325	16.3%
	2022	0.2498	0.4041	0.2080	25.4%
	2023	0.1797	0.2898	0.1499	46.8%
	2024	0.1136	0.1819	0.0951	67.0%
	2025	0.0840	0.1337	0.0706	76.0%
	2026	0.0562	0.0882	0.0475	84.5%
	2027	0.0300	0.0455	0.0258	92.5%
	2028	0.0054	0.0054	0.0054	100.0%

The EGE cross-DRIPE benefit is calculated by multiplying the EGE DRIPE coefficients by the amount of unhedged electric energy purchased in each period. These results are measured in units of $/TWh per MWh saved. Table 90 summarizes the own-state and ISO-wide cross-fuel DRIPE values for 2018 electric energy efficiency installations based upon the electric coefficients in Table 89 and the unhedged energy in each period.

Table 90. Electric-on-gas-on-electric cross-fuel DRIPE by season (2018 $/MWh-saved)

					Electric Summer					
Year	ISO NE	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA	MA
2018	6.41	0.59	0.63	0.12	1.39	0.47	0.90	1.41	0.89	3.20
2019	10.08	0.93	0.99	0.19	2.18	0.74	1.43	2.22	1.40	5.05
2020	11.12	1.03	1.09	0.21	2.39	0.81	1.58	2.45	1.55	5.58
2021	11.16	1.04	1.11	0.21	2.36	0.81	1.59	2.47	1.56	5.62
2022	10.10	0.94	1.00	0.19	2.13	0.73	1.44	2.24	1.42	5.10
2023	6.71	0.69	0.72	0.14	1.54	0.53	0.87	1.35	0.86	3.07
2024	4.27	0.44	0.46	0.09	0.98	0.34	0.56	0.86	0.55	1.96
2025	3.17	0.33	0.34	0.07	0.73	0.25	0.41	0.63	0.40	1.44
2026	2.12	0.22	0.23	0.05	0.49	0.17	0.27	0.42	0.26	0.95
2027	1.14	0.12	0.12	0.02	0.27	0.09	0.15	0.22	0.14	0.51
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
>= 2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized	6.74	0.64	0.68	0.13	1.47	0.50	0.93	1.45	0.92	3.30

					Electric Winter					
Year	ISO NE	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA	MA
2018	14.85	1.45	1.51	0.30	3.14	1.06	2.04	3.26	2.07	7.37
2019	23.39	2.28	2.38	0.47	4.93	1.67	3.21	5.15	3.27	11.63
2020	25.79	2.51	2.63	0.51	5.41	1.84	3.56	5.68	3.62	12.86
2021	25.89	2.55	2.65	0.52	5.36	1.83	3.58	5.72	3.64	12.95
2022	23.39	2.30	2.39	0.47	4.82	1.65	3.24	5.17	3.30	11.71
2023	15.59	1.68	1.74	0.34	3.50	1.20	1.96	3.12	1.99	7.08
2024	9.98	1.08	1.11	0.22	2.24	0.77	1.26	2.00	1.28	4.54
2025	7.43	0.81	0.83	0.17	1.68	0.58	0.93	1.47	0.94	3.34
2026	5.00	0.55	0.56	0.11	1.14	0.39	0.62	0.98	0.63	2.22
2027	2.74	0.30	0.31	0.06	0.62	0.21	0.34	0.54	0.34	1.22
2028	0.57	0.06	0.06	0.01	0.13	0.05	0.07	0.11	0.07	0.26
>= 2029	0.00	0.00	0.00	0.000	0.00	0.00	0.00	0.00	0.00	0.00
Levelized	15.66	1.58	1.64	0.32	3.34	1.14	2.11	3.37	2.15	7.62

Peak and off-peak differentials will be slightly different than the all-hours period data presented due to different amounts of energy consumed during peak and off-peak periods. As seen in Table 91, the indicative values in AESC 2018 are within the same range as the AESC 2015 values. The comparison of levelized DRIPE values is difficult due to different fuel, demand, hedging, and decay assumptions. In aggregate, the AESC 2018 summer values are generally lower than those of AESC 2015 due to the different gas supply elasticity estimates and lower fuel prices. The AESC 2018 winter values are generally in closer alignment because AESC 2015 and AESC 2018 had similar basis estimates and these dominate the results.

Table 91. Comparison of electric-on-gas-on-electric cross-DRIPE in AESC 2018 and AESC 2015 (2018 $/MWh)

Period and AESC Version	ISO NE	ME	NH	VT	CT	RI	MA
Electric Summer Season							
AESC 2015 (Levelized)	11.00	0.96	1.04	0.49	2.76	0.67	5.08
AESC 2018 (Levelized)	6.74	0.64	0.68	0.13	1.47	0.50	3.30
Difference ($)	-4.26	-0.32	-0.36	-0.36	-1.29	-0.17	-1.78
Difference (%)	61%	67%	65%	27%	53%	75%	65%
Electric Winter Season							
AESC 2015 (Levelized)	15.82	1.38	1.49	0.71	3.97	0.96	7.31
AESC 2018 (Levelized)	19.43	2.01	2.07	0.41	4.08	1.39	9.43
Difference (%)	3.61	0.63	0.58	-0.30	0.11	0.43	2.12
Difference ($)	123%	146%	139%	58%	103%	145%	129%

10. TRANSMISSION AND DISTRIBUTION

In addition to avoiding various types of generation costs (energy, capacity, and associated DRIPE), load reductions can contribute to deferring or avoiding the addition of load-related transmission and distribution facilities, due to reduced load growth and reduced loading of existing equipment.[178]

This chapter is new to AESC 2018. Here, AESC 2018 expands upon the treatment of electric T&D Avoided Cost Components in prior AESC studies, which primarily summarized estimates provided by Study Group members.[179] AESC 2018 calculates an avoided cost for Pool Transmission Facilities (PTF) of $94/kW-year in 2018 dollars. Note that this represents the PTF cost only; program administrators can still add avoided distribution and non-PTF transmission costs. Program administrators that use the avoided PTF costs calculated in AESC 2018 should include only local transmission investments (those not eligible for PTF treatment) in their own, additional avoided transmission analyses.

The following steps summarize a standardized approach to estimate generic avoidable transmission or distribution costs that consists of the following steps:

- Step 1: Select a time period for the analysis, which may be historical, prospective, or a combination of the two.
- Step 2: Determine the actual or expected relevant load growth in the analysis period, in megawatts.[180]
- Step 3: Estimate the load-related investments in dollars incurred to meet that load growth.
- Step 4: Divide the result of Step 3 by the result of Step 2, to determine the cost of load growth in $/MW or $/kW.
- Step 5: Multiply the results of Step 4 by a real-levelized carrying charge, to derive an estimate of the avoidable capital cost in $/kW-year.
- Step 6: Add an allowance for operation and maintenance of the equipment, to derive the total avoidable cost in $/kW-year.

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[178] Many energy efficiency programs will be cost-effective without consideration of avoided T&D costs, and many load-control programs will not reliably reduce peak loads on T&D equipment. These will not be eligible to be credited with avoided T&D equipment. For some energy efficiency measures and programs, especially those with very peaky load shapes, the avoided T&D costs may be critical in demonstrating cost-effectiveness.

[179] AESC 2011 provided limited feedback on some of the methodologies used in that year, most of which relied on a spreadsheet developed by ICF in 2005.

[180] The data could be for hypothetical growth levels, but the effort of determining the investments necessary to meet a hypothetical growth level is likely to be excessive. Hence, most analyses rely on actual investments (which are known) or fully-developed investment projects for the relatively short-term future.

The data for this approach may come from historical top-down accounting data, such as from page 206 of the utility's annual FERC Form 1 filing, or from bottom-up data based on past and future expenditures by project or budget line item.

These generic avoided T&D costs are not intended to represent the potential value of targeted load reductions, as part of non-wire alternatives to specific transmission and distribution projects. Analysis of targeted non-wire alternatives requires information about the cost and timing of the specific project to be avoided and the amount of load reduction required to defer project need for one or more years.

The goal of these generic avoided-cost computations is not to identify specific projects that can be avoided, but to estimate the overall, long-term ratio of T&D savings per kW of avoided load growth (and hence of a kW of peak savings).[181] In this approach, historical data can be as meaningful as forecast data, and the sunk costs of planned additions are as relevant as the future costs.

The avoided T&D value is generally applied as if every kW of load reduction in any location will have the same value. This is a useful simplification, which is reasonable for widespread energy efficiency programs. In some places and times, even small load reductions that keep load below the capacity of existing equipment may avoid very large incremental T&D investments. In other places and times, relatively large load reductions may have little effect on T&D investments. The location contributing to new T&D investments can vary from perhaps a dozen residential customers sharing a line transformer to thousands of customers sharing a substation or a transmission line. Since avoidable T&D costs are estimated as the ratio of actual or near-term expected investment to actual or expected load growth, the specific projects used in the analysis are not usually avoided.

Depending on the amount of excess capacity on the various levels of T&D equipment in a particular area, reducing load by any particular customer may avoid addition of a line transformer in the next year; and/or contribute to delaying or avoiding the reconfiguration of feeder; the upgrading of a substation, and the construction of transmission lines in following years. At another location, load reductions may have little effect on T&D investment for many years. Recognizing this complex approach, the approach in this report computes the average ratio of all load-related investments to all load growth, rather than just the load growth that has the greatest effect on investment to develop avoided costs.[182]

AESC 2013 conducted a survey of utility T&D cost estimates. In that survey, we found that most of the sponsoring electric utilities were using avoided T&D cost estimates that ranged from $100/kW-year to $200/kW-year, comparable to or greater than avoided generation capacity cost. Specific values for avoided T&D costs were not presented in AESC 2015. Therefore, avoided T&D costs are significant enough to merit examination in the 2018 AESC study.

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[181] Analysts do not generally have ex post estimates of costs that have actually been (or are expected to be) avoided by energy efficiency; such analysis, if feasible, would usually be prohibitively expensive.

[182] Geographically targeted load reductions, such as part of a non-wires alternative to a transmission or distribution project, may have much higher values, depending on the magnitude and time of need.

The Analysis Team separated the Pool Transmission Facilities, identified the portion that is load-related (rather than generation connection) and performed a traditional avoided-cost analysis. This analysis compared pool-wide investment to the projected pool-wide load growth driving the investment. ISO New England load forecasts have tended to exceed actual loads, so we had to consider how to match load growth and investment.

We identified the portion of the PTF that would be allocated to what ISO New England calls Local Networks, which may cover a single utility (e.g., the CMP, Emera Maine UI and Fitchburg G&E networks) or span multiple states (e.g., the NUSCo, NEPCo, and NStar networks). We then suggested methods for allocating costs among states and/or utilities. Our analysis differentiated PTF costs from zonal needs using ISO New England's Transmission Application Status document, which currently provides data for cost approvals in 2004 to 2016. We developed a single regional avoided cost for PTF, as well as state or transmission-network estimates for other facilities.

For non-PTF transmission, and for distribution, we expanded on the criteria discussed with the study group and discussed methods for estimating avoided T&D costs in the absence of recent or forecast load growth. We also reviewed the methods in use by the utilities and program administrators, and identified areas in which the methods could be refined to better match the criteria.

10.1. Criteria for Avoided T&D Estimation

The following considerations are useful in guiding the estimation of avoided T&D costs:

- **Time period.** In estimating the avoided T&D cost, analysis should use complete, consistent, and reasonable data for both load and investment.
- **Investment plans and budgets for any future period must be reasonably complete.** For example, a utility may have a 2018 construction budget through 2025, but that budget may include only a few long-term projects.
- **The analysis period should provide a reasonable proxy for the long-term relationship between load and investment.** If the period starts with the system overbuilt due to unexpected load reductions, the analysis will tend to understate the cost per kilowatt and vice versa. The analysis should avoid or correct for unrepresentative conditions due to unexpected growth or deferred investments.

On a related point, weather-normalized loads may be more representative than actual loads in determining the amount of load growth in the analysis period. Taking actual load growth from a hot summer with high loads, to a mild summer with low loads, would understate the amount of load growth driving the investment, and vice versa.

Some T&D investments are driven by load growth from new customers in areas that are not currently served, or are not served in a manner that would accommodate the growth, even with very aggressive energy efficiency efforts in new and existing loads in the area. For example, serving major commercial development in a previously residential exurban area or a 100-unit residential development in an agricultural area may require a new substation or feeder respectively, regardless of any conceivable load reduction. Analyses of avoided T&D costs generally omit these projects; where possible, the load growth served from these projects should also be omitted from the computation.

Even utility systems with little total load growth tend to have areas in which peak loads are growing, offset by areas in which peak loads are declining (due to some combination of energy efficiency programs, other conservation, and economic and demographic trends). In those situations, the computation of avoided T&D costs should ideally represent the investments in the growing areas, divided by load growth in those areas, and adjusted down to reflect the portion of loads in the reas with growth. This greater level of detail is rarely possible, especially on a feeder-specific or transformer-specific basis.

Investments should be converted to some common price basis (such as by adding or removing inflation) so that investments in 1993 and 2023 (or whatever years are used) can be added together. Any projections or hypothetical adjustments to the historical periods should be handled consistently for load growth and investment.

The AESC avoided costs are based on a hypothetical world in which no energy efficiency programs are implemented going forward. For consistency in identifying the full T&D costs avoidable by energy efficiency programs, it would be desirable to start with the loads that would have occurred and the investments that would have been needed without energy efficiency efforts. Estimating the effect of the energy efficiency programs on historical and forecast loads may be feasible. Unfortunately, estimating the T&D investments that would have been needed without the energy efficiency programs is generally infeasible, requiring a large amount of engineering analyses to develop hypothetical needs at the feeder level.[183]

If a fully consistent no-EE analysis could be performed, that would be ideal. But an analysis that combined loads from a "no-EE" premise with investments from the "with-EE" reality would understate avoidable costs.

Disaggregation of growth

For each type of equipment, the computed load growth should reflect the load on that type of equipment. The T&D system consists of several types of equipment, which may be simplified into the following categories:

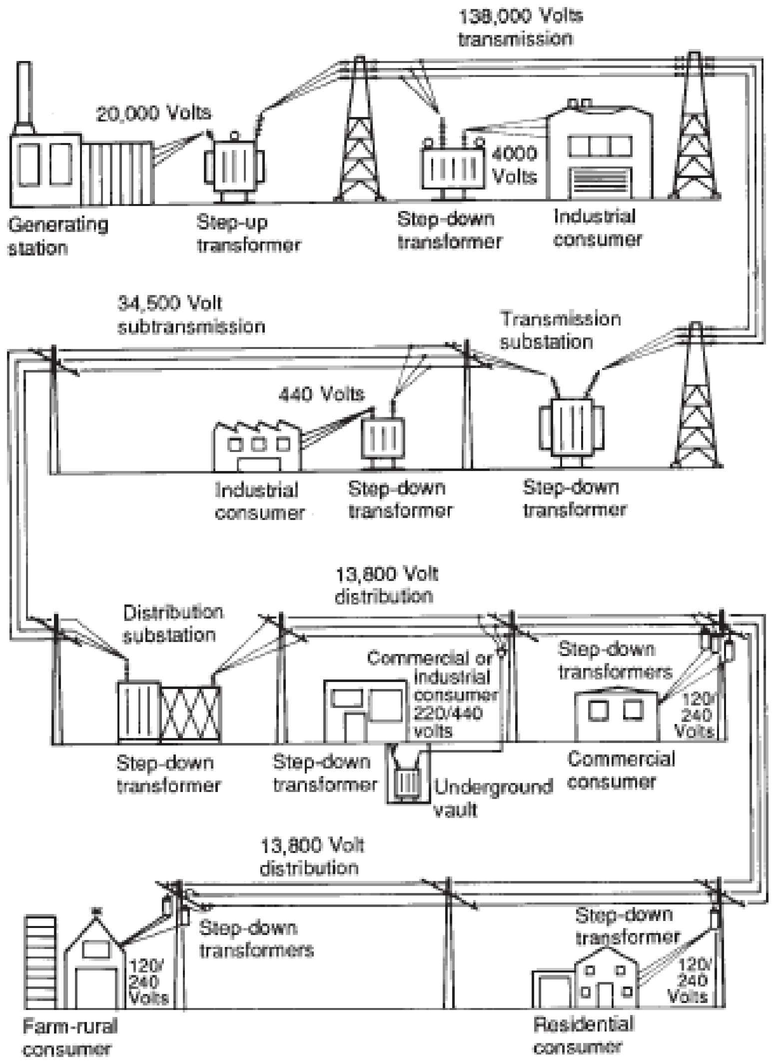
- high-voltage transmission lines (115 kV to 345 kV);

[183] The actual and projected energy efficiency may have avoided the planning and construction of more expensive T&D projects, but those costs are not generally available. The available data generally estimates the benefit of additional load reductions, on top of those that have occurred and are planned.

- transmission substations connecting transmission lines at different voltages;
- subtransmission lines (e.g., 69 kV) that connect to distribution substations and some very large customers;
- bulk distribution substations that step transmission voltages down to generally high distribution voltages (mostly at 13.8 kV to 25 kV);
- high-voltage primary feeders that distribute power from the bulk substations to lower-voltage substations, some primary-voltage customers, and line transformers;
- lower-voltage substations that step down the power to lower (mostly legacy) voltages, in the 2 kV to 8 kV range;
- low-voltage primary feeders that distribute power to primary-voltage customers and line transformers;
- line transformers that step power down from the primary distribution voltages (2 kV to 35 kV) to secondary voltages (110 V to 500 V);
- secondary lines from the transformer customer service drops; and
- service drops from the street to customer meters.

Figure 41 illustrates the general design of T&D systems. The range of voltages considered to be subtransmission varies among utility systems.

Figure 41. Schematic of a T&D system



Any load reduction may result in avoidance or delay of investments at one or more of these levels, in the near term or over many years.

All loads use transmission; primary and secondary loads use the primary distribution system; and only secondary loads uses line transformers and secondary lines. Hence, T&D analyses should not use the same peak loads for both transmission and distribution capacity. The load growth used in the distribution analysis should generally be lower than the load growth used for the transmission analysis.

Computation of T&D avoided costs

Generally, the computation of avoided costs in $/kW should use the same measure of load that will be used in screening. This criterion requires that the units of load reduction used to attribute avoided costs to programs be consistent with the units of load used to compute those avoided costs. The units should be consistent on a number of dimensions, including the timing of the load peaks, the treatment of seasonal load, the use of normal or extreme loads, and the treatment of losses.

Generation capacity avoided costs are driven by load at the time of the ISO New England peak, which has by convention associated with an hour ending at 3 PM or 5 PM on a hot summer day. For simplicity, energy efficiency screening often uses these same peak conditions for estimating contribution to T&D peaks, in which case the avoided T&D costs should be computed per kilowatt of growth in contribution to regional peak. Since T&D assets reach their peak loads at different times, in both summer and winter, some utilities may use a different measure of peak load (e.g., sum of class peaks, sum of summer and winter peak) to derive the $/kW ratio, in which case that alternative measure of peak load should be used for valuing the T&D savings in the screening process.

If the avoided T&D costs are to be allocated between summer and winter peak contributions in screening, then the avoided-cost analysis should similarly reflect both summer and winter load growth. Assuming that winter peak growth equals summer peak growth is rarely realistic.

Transmission and some distribution facilities are planned for extreme weather (or other conditions), such as those in the ISO New England's 90/10 load forecasts. It may thus be tempting to divide investment by the growth in load that would occur under extreme conditions, rather than normal peak conditions (e.g., those that would be expected to be exceeded about half the time). If the analysis computes avoided T&D costs in $\$/kW_{extreme}$, screening must use estimates of load reduction under extreme conditions. For some end-uses, load reductions will be very similar at normal and extreme peaks, but for others (air conditioning and solar in the summer, heating in the winter) the reductions under extreme conditions will exceed those at normal peaks.[184] If screening assumptions cannot be developed for extreme conditions, analysts should avoid the use of extreme loads in the avoided-cost analyses.

Similarly, if screening uses load reduction at the end-use, the avoided T&D costs should use load growth at the end-use, or (if load growth is measured at transmission level) a loss factor must be added to the avoided cost.

Identifying load-related investments

The investment should include all identifiable load-related costs, but no more. AESC 2018 recommends using top-down accounting analyses to identify the accounts that are primarily load-related, and net out an allowance for the costs of replacing retired equipment in kind. The FERC Form 1 data include both additions and retirements by account. Bottom-up analyses should be used to identify the projects and blanket accounts that are primarily load-related.[185]

[184] Something must use more energy at the extreme peak, or it would not be an extreme peak.

[185] A blanket account in the context of distribution utilities typically includes a large number of similar investments, such as substation upgrades or line-transformer replacements.

For the bottom-up analyses, AESC 2018 recognizes that differentiating investments between those required by load growth from those required for other considerations can be complex. The non-load-related investments may include:

- Distribution assets (primarily meters and services) that are driven entirely or predominantly by the number of customers.[186]
- Primary distribution projects that extend service into areas that have not previously been served, to connect new customers. New construction energy efficiency programs may avoid a small portion of the wire costs. However, most of the costs are related to the extension of supply to new areas.
- Some transmission projects that are required to integrate generation or allow targeted imports. Generation interconnection costs will generally be included in the generation market prices. Transmission projects supporting policy-driven imports of renewable energy from Canada or offshore wind are unlikely to be affected much by load reductions, at least in the short term.[187]
- Some distribution and transmission investments simply replace old equipment. Other investments relocate facilities due to road widening, loss of easements, and similar factors. Neither type effects are load related.

In contrast, other investments are clearly required to accommodate load growth, including:

- Most new transmission lines and substations and additional transformers at existing substations;
- Additional feeders and line transformers in areas with existing service;
- Reconductoring of lines to increase capacity;
- Increasing the voltage of transmission or distribution lines; and
- Conversion of single-phase feeder branches to two-phase or three-phase operation.

A third set of investments is harder to characterize, including such situations as:

- Investments triggered by factors other than load, but whose cost is increased to accommodate higher load levels. For example, if rotting poles are being replaced with taller poles so that the feeder voltage can be increased in the

[186] Service drops are often sized or upgraded based on the end-uses in a building. In principle, energy efficiency should reduce the required service size and cost. It is not clear how consistently utilities or contractors take building efficiency into account in determining the size of the service drop to be installed.

[187] Energy efficiency measures installed in the near term may (by reducing the use of fossil generation) reduce the motivation for further clean-import mandates and associated generation. Predicting the timing of future initiatives may be challenging.

future, the incremental cost of the taller poles is load-related.[188] The cost of replacement may be unavoidable, but the load-related improvement may be avoidable.[189]

- The costs of removing aging, but functional equipment to allow installation of higher-capacity equipment. The existing equipment might need to be replaced in another decade or two, even without the load growth, but most of the present value of the replacement cost would be due to the load-related timing of the project.

- Investments required to complete or modernize projects already in service, such as improved lightning arrestors or added SCADA equipment on existing feeders. These investments may be considered as a continuing cost of the original load-related projects (as post-operational capital additions are considered part of the cost of a power plant), and hence an adder to avoided cost (perhaps computed in dollars per MW of load, rather than dollars per MW of load growth). On the other hand, if the improvements are being driven by a one-time change in reliability or safety standards or technology, perhaps no similarly deferred improvements should be anticipated for equipment driven by future load growth.

- Replacement of equipment degraded by both age and loading levels. For example, high loads (especially high loads over many hours in a day) increase the rate at which insulation breaks down in underground lines, substation transformers and line transformers. High loads on transmission lines also increase the line sag (possibly violating clearance requirements) and weaken the conductor. Replacements of load-carrying equipment will generally be at least partly driven by load levels, but the extent of this effect may be difficult to separate from the effects of time.

- Investment driven by load-related energy considerations, including transmission congestion relief and reduction of line losses.[190]

AESC 2018 recognizes that these situations complicate the neat division of projects and accounts into load-related and non-load related categories. Classification of specific projects or accounts as avoidable or unavoidable by energy efficiency should be clearly documented and explained.

Matching investment to load growth

Bottom-up analyses should include all the investment in load-related equipment entering service in the analysis period, including investment prior to the start of the analysis period. Any project costs that

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[188] If new poles are required due to rot and the taller poles would be required to meet clearance at the current voltage, they are not load related.

[189] In principle, the decision not to downsize the replacement may also be load-related, but this component of project cost may be difficult to quantify.

[190] Line losses should be computed on a marginal basis, where possible.

stretch beyond the in-service date of the equipment (e.g., for removal of retired equipment, environmental compliance, addition of communications or control equipment) should be included, as well. Top-down accounting-based data will include all the costs of a project in the year that the project enters service, but may count some deferred costs in the following year.

The load growth used in computing avoided distribution costs should reflect the loads at the distribution level, excluding loads served directly from transmission lines, for which the utility does not provide distribution equipment. Similarly, where the avoided cost of secondary distribution is computed separately from the primary distribution, the load growth should reflect only the loads served at the secondary distribution level.

While the load growth used in computing avoided distribution costs should reflect the loads of customers served at distribution, the growth in distribution loads may be stated in terms of megawatts at the transmission level, at distribution, or at the meter.[191] Contribution of distribution loads to system or area peaks are highest when measured at the transmission level, lower at the distribution level, and still lower at the customer's meter. This is because the transmission-level loads include line losses from the meter to transmission, distribution-level loads include line losses from the meter to the feeder or substation, and loads at the meter include no losses. As a result, the avoided costs will be higher measured as $/kW at the meter and lowest as $/kW measured at transmission. Since energy efficiency program load reductions are generally estimated at the end use, the cost-benefit analysis must reflect avoided costs at the end-use (or the customer meter, as a proxy for the end-use). If the avoided cost is computed per kilowatt of load data at the transmission level, losses from the meter to transmission must be added back to get the avoided cost in $/kW of load at the meter.[192]

Dealing with absence of system load growth

Some utilities have experienced little or no overall growth in total load for some years and may forecast little growth in peak loads for some years. Nonetheless, a utility can have load-related investments to address parts of their service territories that are experiencing load growth. Dividing the load-related investments by zero, a negative number, or even a small positive load growth will produce meaningless results. In those situations, the utility may either use historical data from a period with load growth, or compute the avoided cost per kilowatt growth for the fraction of the system that has experienced growth. The AESC Reference case assumes a world with no new energy efficiency programs, in which the avoided costs computed for the areas with growth would be applicable to the entire utility.

[191] Regardless of where load is measured, it should include only the contribution from the voltage levels driving the need for that type of equipment (i.e., all distribution load for substations and feeders, secondary load for transformers).

[192] Similarly, if the load growth is estimated at a distribution voltage, the avoided cost must be increased by the losses from the meter to that voltage.

Carrying cost

The annualization of the capital costs should reflect the utility's cost of capital, income taxes, property taxes, and insurance. The useful life used in determining the carrying charge should match the expected life of the equipment. If a transmission plant has a longer operating life than distribution plant, the analysis should use a lower carrying charge for transmission than distribution. This is one reason that avoided transmission and distribution are usually computed separately.

The carrying charge should be computed in $/kW-year levelized in real terms. The real-levelized carrying charge is the first-year charge that, if escalated at the inflation rate, will have the same present value as the revenue requirements for the project or the nominally levelized charge. The real-levelized carrying charge in each year represents the present value benefit of a one-year delay adding the investment, and hence a one-year reduction in load growth.

Annual revenue requirements, real-levelized costs, and nominally levelized costs have the same present value, but the revenue requirements are front-loaded. Nominally levelized costs are flat in nominal terms and real-levelized costs are flat in real terms, rising with inflation.

Operation and maintenance

Most T&D plant additions (a new transmission line, substation, feeder, or line transformer) also incur additional O&M costs, such as for vegetation control, inspections, repairs, repainting of towers and structures, and the like. Some expenditures, such as reconductoring a feeder or replacing poles for a voltage upgrade, may not increase (and may actually decrease) O&M costs.

The best practice for extrapolating O&M from historical data would generally be to determine the unit O&M cost ($/MVA of substation operation and maintenance, $/mile of feeder) and apply that value to the avoided cost. That process is straightforward for additional substations and transmission lines, which have their own accounts in the FERC Form 1, but would be more difficult for other distribution facilities for which O&M expenses are less clearly delineated. It is generally reasonable to assume that the ratio of O&M cost to gross plant for the avoidable capacity is the same as for the existing plant mix, although ideally the historical investments would be restated to include inflation. Any assumption that O&M associated with new equipment is less than the average O&M for similar existing equipment should be carefully considered and fully justified.

In addition to avoiding new facilities and their O&M, lower loads will also tend to reduce the rate of failures of existing equipment and thus the capital and O&M costs involved in repairing and replacing the damaged equipment.

Overheads

Utilities generally allocate a range of overhead or administrative costs (e.g., senior management, legal, financial, human resources, purchasing and contracting, information technology, warehousing, office expense, vehicles) on labor or a similar broad measure of O&M and construction costs. Some of those overheads may not vary linearly with the number of personnel required to design, build, maintain and operate the assets, but increased construction will generally require more of the overheads as a whole.

The utility's overhead adders should be included in both the load-related investments and the associated O&M. Any exclusion of overhead costs from avoided T&D investment should be carefully considered and fully justified.

10.2. Utility-Supplied Data on Avoided Costs

The following section describes our review of data provided by participating utilities that informs the T&D avoided cost quantification approach.

We have not reviewed any avoided T&D analyses from Eversource's Massachusetts and New Hampshire subsidiaries, the Maine utilities, or Vermont. We have reviewed some data for these utilities on the load growth and avoidable costs in some congested areas that may be suitable for targeted distributed resource solutions in pending New Hampshire pilot programs. But we have not found any computations of general avoided T&D costs for energy efficiency screening.

National Grid

National Grid provided a 2015 spreadsheet with separate analyses for transmission (for NEPCo), Massachusetts distribution, and Rhode Island distribution, using historical data for 2009–2013 and forecasts for 2014–2019. National Grid also provided a 2018 update for transmission and Rhode Island distribution, using historical data from 2012–2016 and forecasts for 2017–2022. The spreadsheet was fairly self-explanatory, since it contained many embedded comments. Some important information was redacted or inserted as values, so the origin of some inputs cannot be determined or reviewed.[193] National Grid staff also discussed with the AESC Analysis Team potential improvements to its methodology.

National Grid presented, but did not use, data dating back to 1998 for distribution and 1993 for transmission. Data from some of these earlier years might provide representative results for AESC 2018, which includes load growth faster than recent or forecast actual growth (given the lack of energy efficiency). National Grid might want to think through the applicability of older data and explain its choice of historical period.

The analysis categorizes just 5 percent of transmission. This appears to be an outdated assumption, which National Grid is currently reconsidering. Most transmission investments are load related; from the project descriptions in the ISO's Transmission Cost Allocation (TCA) reports, about 70 percent of NEPCo's

[193] We have no information on which projects were treated as load-related, so we cannot comment on the propriety of those decisions.

projects in 2004 to 2017 were load-related, with the remainder related to rebuilding poles and other facilities and other non-load-related upgrades.[194]

If National Grid uses the estimates of avoided PTF developed below, it should omit the PTF costs included as PTF from its analysis of local transmission. The vast majority of National Grid's post-2004 transmission investment is included in the avoided PTF cost, but NEPCo has made some investments in facilities below 115 kV.

Similarly, the 2015 analysis treats 18 percent of Massachusetts distribution and 25 percent of Rhode Island distribution investments as load-related; the Rhode Island value is reduced to 18 percent in the 2018 spreadsheet. The 2015 spreadsheet says that "The percentage due to load growth would be between 35–40% in Massachusetts and all the way up to 50%+ in Rhode Island." It selects the low end of the ranges (35 percent and 50 percent), and then divides those in half because "half of the investments associated with load growth are deferrable through [energy efficiency]." National Grid staff clarified that the "percentage due to load growth" included "new business" projects and that the 50 percent reduction was intended to remove those costs from the load-related category. Some costs of the new-business projects may well be unavoidable through plausible load reductions. For example, most of the costs of extending a feeder to serve a new subdivision or mall in what used to be farmland may be unavoidable, even if the new load were reduced by half and regardless of reductions in existing load. We do not know how National Grid defined "new business" or what sort of projects were included in that category. National Grid's result is plausible, but we were not able to review the derivation of the inputs (the 35 percent and 50 percent values that were found to be load-related in the broader sense, and the 50 percent reduction due to exclusion of new business) are not reviewable.

The load levels used in the transmission and distribution computations are at the transmission level.[195] The load of customers served at transmission voltage should not be included in the distribution analysis. The National Grid 2015 analysis provides a breakout between primary and secondary marginal distribution cost, that analysis does not appear to use different load levels for primary and secondary.

The spreadsheet notes suggest that "Peak forecast data used should be consistent with the company planning policy (for example, if transmission investment is based on extreme weather expectations, the extreme weather peak forecast should be used)." As noted above, that would only be appropriate if screening can use extreme weather load reductions, which is not generally possible. The 2015 spreadsheet also notes that the load forecast is "from a 50/50 scenario," so it looks like National Grid properly used the normal peaks, for which measure savings estimates are available.

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[194] If National Grid uses the avoided TCA costs from PTF estimated below, it should remove the TCA projects from its estimate of avoided load transmission.

[195] The spreadsheet notes state "For consistency with the historical data, the forecast should be at the generation level." The forecast for each type of investment (transmission, primary, secondary) should include only the loads affecting that type of investment, and losses should be reflected by removing losses from load or by adding losses to the result.

In the 2015 analysis, National Grid also increased all the loads from 2014 onward to remove the effects of its energy efficiency programs, not just installations after 2013 but for some longer prior period (the 2014 adjustment is about 6 percent of the load forecast). The projected investments were not similarly adjusted upward to correspond to the needs without energy efficiency savings which results in an understatement of per-unit avoided costs. In principle, avoided T&D costs can be computed by comparing actual and forecast load to actual and forecast investment, or by comparing load with higher growth to investment with higher growth. Since developing a hypothetical T&D investment would be a substantial undertaking, we understand that National Grid's future T&D analyses will compare actual and forecast investments and loads.

National Grid quite reasonably computes O&M as a percentage adder on total embedded nominal net plant and applies that adder to the cost of new equipment. The use of embedded nominal net plant, rather than costs in the dollars used in the investment analysis (2013$ or 2016$), probably overstates the ratio of O&M per dollar of investment. On the other hand, in computing the ratio of O&M to capital, National Grid excluded part or all of several O&M accounts. Some load-related projects may not increase O&M costs: a feeder that is reconductored to carry higher current may not require any more inspections and repair than the facilities it replaces. But many projects will increase costs. For example: a new substation will require maintenance and inspection, and new transmission lines will require vegetation clearing. National Grid should use the historical ratio of O&M to investment, either for distribution as a whole or differentiated among substations, overhead lines, and underground lines (including allocation of supervision, engineering, and miscellaneous expenses), with explicit adjustments for categories of projects that do not increase O&M, if National Grid identifies such projects.

Overall, the National Grid methodology, with planned changes, appears to be reasonable.

United Illuminating

United Illuminating (UI) presented avoided distribution costs for conservation and load management (CLM) programs based on the marginal cost methodology it uses in Connecticut, which UI describes as being "based on a sampling of T&D projects designed to address only system load growth."[196] UI has also indicated that it "does not have an opinion on which methodology is superior" and noted that its methodology has been accepted by the Connecticut Public Utilities Regulatory Authority.

UI provided a text report (Avoided Transmission & Distribution Cost Study, 2000–2026, August 1, 2017) and two spreadsheets: the derivation of UI's marginal distribution cost estimates ("UI Marginal Study 2017 July14 (3).xls") and derivation of an avoided cost for energy efficiency, which relies on the marginal cost spreadsheet.[197] Those documents provide a reasonably complete explanation of most parts of UI's methodology, which is generally appropriately structured.

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196 In Connecticut, energy efficiency programs are part of the CLM portfolio.

197 These documents were created by Harbourfront Group, Inc.

The marginal cost study excludes transmission projects because “there were no avoided transmission substation or feeder costs for either the historical or the future period, which total 2000–2026, and “there were no transmission substation or feeder projects which added capacity to the UI transmission system.” Once the costs of the pool transmission facilities are accounted for (as described below), UI may not have any recent or projected load-related transmission costs. The ISO New England TCA reports assign about $15 million as local UI T&D costs; it is unlikely that none of these costs are load-related.

To estimate marginal distribution cost, the UI Marginal Study 2017 identified specific load-related expenditures in the period 1999 to 2026. It calculated a total substation and feeder plant addition as the sum of those expenditures, then divided this by the sum of the rated capacity additions of the projects, as discussed above. It then applied an economic carrying charge and a loss factor of 2.9 percent to derive an annualized long-run marginal cost. UI developed the economic carrying charges separately for transmission substations, transmission lines, distribution substations, and distribution lines; the treatment of the cost of capital, taxes, inflation, service life, and other inputs is transparent and reasonable.

As in the case of transmission, the UI Marginal Study 2017 does not provide project-specific information on the excluded distribution projects. However, some of the reasons offered for excluding certain categories of projects suggest that UI did not include additional investments that were or will be required to serve load growth. UI may wish to address the following issues, either by expanding its explanations or modifying its assumptions.

- The Study excludes all secondary distribution because planners design the system to meet predetermined customer load requirements and “established standards.”[198] Additional and/or larger line transformers (or secondary lines) to serve growing load are load-related. Harbourfront observed that distribution transformers are sized based on the estimated load at the time the transformer is installed, based on the characteristics of the customers attached to that transformer. Utilities do not usually swap out transformers as load falls, but they do add transformers as load increases, from new customers in the area (e.g., a residential block, shopping mall, an office park, a downtown network) and equipment added to existing customers. There are thus three categories of energy efficiency projects in terms of their effect on distribution transformer additions: load reductions in new construction (for which UI sizes the transformer(s) to meet expected load), load reductions in areas with rising loads that could require transformer additions, and load reductions that simply increase the excess capacity on the transformers. UI and Harbourfront assume that all energy efficiency projects fall in the third category, which may be unlikely. UI says that it “does not track but is aware of many transformers being retired early so that a larger transformer can be installed due to customer load

[198] The Study says that “this plant type is based on the particular requirements of the customer when service is first connected and cannot be avoided based on changes in the customer’s future loads,” suggesting that the authors believed that load in a local area can only fall after the initial installation of the distribution system.

growth." UI may wish to reconsider how to estimate the effect of CLM on the number and sizing of those load-growth-related transformers, along with the effect of new construction programs on transformer sizing.

- The Study also says that it excludes distribution transformer additions to supply new load, because "the new load is assumed to be the loading after the customer has implemented CLM program and therefore the load would not be deferred by CLM activities." By this argument, no actual or planned distribution expenditure to meet load growth should be treated as avoidable, because the investment occurred or is planned. While some of the line transformer costs to serve new customers in new areas will be unavoidable, more efficient building envelopes and downsized cooling systems will allow smaller (or fewer) transformers. If the new load is in an area already served, increased efficiency of the existing load and the new customers may similarly result in smaller and/or fewer transformers. As noted above, distribution transformers are sized to address the known load of the customers attached at the time the transformer is installed. UI and most other utilities would not replace an existing transformer with a smaller one if CLM projects are done by those specific customers. UI does not track but is aware of many transformers being retired early so that a larger transformer can be installed due to customer load growth. Therefore, UI stated that it decided to exclude transformer costs since CLM projects would have no effect on distribution transformer costs.

- The Study excludes feeder extensions that "[enable] reconfiguration of existing circuits in a geographical area to maximize the regional available substation capacity." Investments that are required to enable the existing substations to serve more load should be treated as load-related, even if the project does not increase the capacity of the substations. UI notes that reconfiguration is not expensive, so the effect of these projects on avoided distribution costs may be small.[199]

- The Study excludes all voltage conversion projects, even though voltage upgrades are frequently intended to increase capacity. UI has clarified that its voltage upgrades, like National Grid's, are driven by efforts to standardize equipment rather than to maintain adequate voltage and avoid overloads as load grows.[200]

UI divides the identified load-related investment by the MVA capacity of the installation, rather than by the relevant load growth. This may over- or under-state the cost per kW of load growth. UI could test the reasonableness of its load-growth proxy by comparing the MVA capacity of new equipment to the

[199] Harbourfront notes that this was considered to be "circuit balancing" and does not provide any additional capacity than what was already installed on the system. Therefore, these very low cost per MW projects were excluded from the study.

[200] UI is increasing from 4KVA to 13KVA distribution voltage. However, UI is not increasing available capacity on such circuits. Many of these conversions are done to replace older equipment that may be difficult to maintain going forward.

load growth in the areas that drive the need for the equipment.[201] Since capital projects often come in large capacity increments, a small amount of load growth in one area will require an expensive addition, and a large amount of growth in one area will not require an addition, due to the excess capacity installed in previous upgrades.[202]

UI includes O&M in the economic carrying charge, estimated from the ratio of O&M to plant in 2006–2015. UI uses the full O&M cost for substations, but only a portion for feeders, based on a minimum-system study. It is proper to exclude O&M on non-load-related investments. Since UI includes only load-related feeder investments, the O&M on the load-related feeders should be:

load-related feeder investment × [(total feeder O&M) ÷ (total feeder investment)]

Note that Harbourfront method appears to estimate the O&M on load-related feeders as:

load-related investment × [(total O&M) ÷ (total investment)] × [load-related feeder %]

The last term appears to be redundant; if a project is needed due to load level (and not to reach customer locations not currently served), no deduction for customer-related costs seems appropriate.

The avoided-cost spreadsheet had one more important detail. In it, UI reduced the $90/kW-year marginal distribution costs it computed in the marginal cost analysis and multiplied that marginal cost by 45 percent, the ratio of total distribution feeder peak load to total capacity. UI already divided the cost of new equipment by its capacity (rather than the load growth or even load on the equipment), so this adjustment appears to be redundant. UI should reexamine this treatment, along with the use of the equipment MVA, as discussed above.

Eversource (Connecticut Light and Power)

The Eversource (Connecticut Light and Power, or CL&P) analysis is presented as a report on avoided T&D from ICF (Assessment of Avoided Cost of Transmission and Distribution System Investments in Connecticut, July 17, 2017) and an accompanying spreadsheet. Eversource also provided some comments from ICF in response to a draft of this report, and Eversource and ICF staff participated in a teleconference with the AESC 2018 team. The avoided-cost methodology is based on the marginal cost computations that CL&P has used in retail rate proceedings.

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201 Since not all areas are growing, UI would also need to estimate the percentage of load in the areas that have or will require reinforcement.

202 UI states that using the capacity of the additions, rather than the load growth requiring the additions, is consistent with the method that the PURA has previously accepted. Note that AESC 2018 concerns only avoided costs, not marginal cost for rate design.

ICF used transmission capital expenditure data for 2002–2016 and projections for 2017–2022.[203] ICF excluded about 95 percent of these costs, on the grounds that they are related to reliability. ICF says that "reliability projects may have some avoidable components. For example, a load reduction may allow for deferral of a reliability project to a later date, or may even serve as a substitution for a T&D reliability investment."[204] In its comments to the Analysis Team, ICF clarified that the "reliability" projects were pool transmission facilities, which might be required by loads outside the CL&P service territory. That explanation is reasonable, so long as the PTF costs are added separately (and assuming that the reliability/PTF projects were properly identified).

The ICF analysis regressed annual transmission investment against a stream of total load. Regressing investment on load is an appropriate approach, although we have concerns about an important aspect of the model.

First, ICF uses only nominal dollar costs in its computations (although some of those values are inadvertently labeled as real costs), which are not comparable between years. It is not clear how the results of a regression on nominal dollars can be interpreted. Eversource should put costs in real terms in future analyses.

Second, rather than using the costs directly in the regression, ICF created what it calls a "smoothed" non-PTF investment stream, by weighting the current year's investment 7.5 percent and the previous year's weighted investment 92.5 percent. This computation results in ICF weighting the low $2.2 million investment in 2002 (less than a quarter of the average, and the third-lowest year in ICF's data) about 10.5 times, but weighting only about half the $60 million in 2012–2013, 27 percent of the $26.9 million investment in 2018 and 21 percent of the $18 million investment in 2019. Other than 2002, no more than 77 percent of the investment in any year is included; the total of the "smoothed" cost then represents 59 percent of the non-PTF investment for 2002–2021.[205] Compared to the actual cost data, the values used in the regression are both lower and very differently shaped over time. If the actual data do not produce useful regression results in future analyses, Eversource might consider using the ratio of investment to load growth, rather than changing the input data.

Third, while the cost data that ICF used are actual investments for 2002–2016 and a 2017 investment forecast for 2017–2021, it used load data through 2014 from the 2005 Connecticut Siting Council (CSC) report and forecasts load after 2014 using the average growth rate from 2001 to the 2005 forecast of 2014 peak. As shown in Figure 42, the actual loads, weather-normalized loads and the Eversource 2017

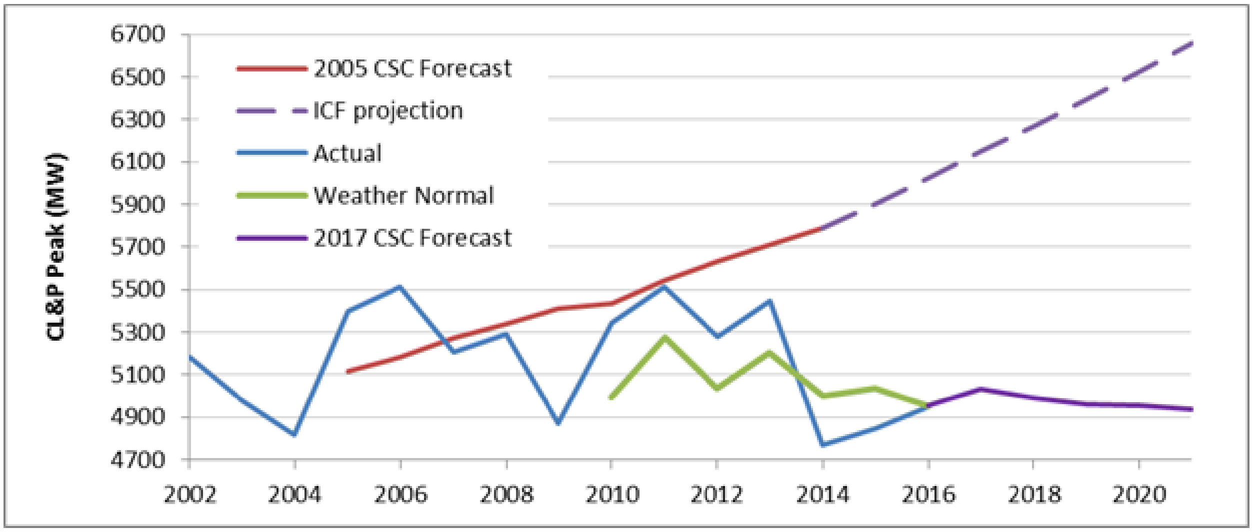
[203] The ICF workbook provides transmission (and separately, distribution) plant in service and net additions from the FERC Form 1 for 2002–2016, but actually uses a different array of expenditures, which are apparently expenditures in each year, rather than the additions to plant in service. ICF has forecasts of investment and load growth through 2026, but does not use them.

[204] ICF Report at p.4.

[205] ICF asserts that it intended to apply "a lag between the year in which the peak demand occurs and the year in which the related investment is made." (Private communication via Joseph Swift) ICF actually lagged the cost, not the demand. Only half the cost is recognized by year 8; even after 30 years, ICF would include only 90 percent of the cost.

forecast (roughly contemporaneous with the investment forecast that ICF used) show loads much lower than the 2005 forecast. While some of the projects shortly after 2005 may have been implemented in response to the 2005 CSC forecast and later projects may have been built due to later forecasts that were higher than actual loads, CL&P was not using the 2005 forecast to build transmission in 2012, or plan 2020 transmission in 2017. Matching investment to the load growth that required the additions is vital in estimating marginal or avoided T&D.[206]

Figure 42. Loads used in ICF analysis, compared to actual and current forecasted load



Fourth, ICF combines a cumulative value (total load) with an annual incremental value (new investments), rather than using the approaches of (1) regressing cumulative load growth on cumulative investment or (2) taking the ratio of cumulative load growth to cumulative investment. The resulting regression coefficient of $4,605/MW is in $/kW of total load, rather than $/kW of growth. ICF believes that this approach is reasonable, in that "ICF's regression assumes annual transmission investments are driven by peak demand in a particular year… For example, ISO-NE, Eversource and other transmission providers typically analyze system operation during the peak period to determine the transmission infrastructure required to serve demand. The annual transmission investment is therefore related to peak demand in a year, and not to the change in demand".[207] The alternative approach is to regress

[206] ICF acknowledged that it had used outdated forecasts in this analysis and suggested that using lower load growth in the analysis would reduce the avoided $/kW. This result is counterintuitive, but could occur with some model formulations.

[207] ICF also stated in its comments that "While the average spending per unit load was understated [due to the use of the 2005 forecast], the investment we are considering is not that related to average load, but rather to incremental load." That statement suggests that ICF believes that incremental expenditures could be compared to incremental load as an alternative method.

total investment (usually since a starting date) on total load, or compute the ratio of investment over a time period to the load growth over the same period.[208]

In its initial report, ICF multiplied the regression coefficient by a 42.17 percent carrying charge to derive an avoided transmission cost of $1.27/kW-year.[209] In its follow-up comments, ICF agreed that it had made some errors, and revised the transmission carrying charge to 22.13 percent (and indicated that the rate was intended to be nominal, rather than real). ICF recognizes that this value is extraordinarily high and attributes the result to an estimated 11 percent property tax on transmission.[210]

A more conventional analysis (dividing the 2002–2021 investment that ICF identifies as load-related by the load growth ICF used) would produce an avoided non-PTF avoided transmission cost of $131/kW. Using National Grid's 9.9 percent carrying charge, or UI's 10.6 percent, that would be about $13 or $14/kW-year, ten times ICF's estimate of $1.27/kW-year. Including Handy-Whitman transmission escalation, the total cost would be about $16/kW-year.

For distribution costs, ICF utilizes a similar methodology, except that it starts with annual distribution investments for 1990–2022 and conducts a regression on customer number to determine that customer numbers cause about 5 percent of distribution investments.[211] ICF again regresses annual investment on a cumulative value (in this case, customers), so the results may be understated. ICF implicitly assumes that the capital investment in a given year is the same for existing customers (most of whom require no investment) and new customers (who require meters and services). Simply removing the non-load-related costs (services, meters, and any feeder and transformer costs driven by new customers rather than load) would identify load-related costs more reliably than ICF's regression.[212]

ICF uses loads from the same 2005 forecast for distribution that it used for transmission. Since distribution load is less than transmission load, ICF overstated distribution loads even more than transmission load. ICF again regressed annual incremental investment against total load, but came closer to matching the load growth and investment periods.[213] The 2017 ICF report used a 30.75 percent carrying charge to derive an avoided distribution cost of $39/kW-year; ICF has corrected the carrying charge to 11.2 percent (this is a plausible value, depending on what costs—such as property tax— it

[208] The regression equation that ICF estimated actually implies that doubling load growth from 1 percent to 2 percent annually would increase load-related investment only about 1 percent, even though there would be twice as much growth.

[209] ICF also multiplied the regression coefficient by annual load growth (77 MW/year) and the length of the study period (20 years) and divided by the product of load growth and study period (1,531 MW), resulting in no net change.

[210] ICF observes that this tax rate was calculated using FERC Form 1 data.

[211] ICF did the same for transmission, but did not find usable results.

[212] ICF indicates that it did not have sufficiently granular data to classify feeder costs. However, this information may be available via annual FERC Form 1 reporting, or from project justification documents (which may indicate whether lines are added to serve new areas or to increase capacity to areas already served).

[213] ICF used loads from one year earlier than the investments.

includes), reducing the avoided cost estimate to $14/kW-year).[214] If ICF had used a conventional approach, starting with its investment data net of the 5 percent identified as customer-related ($7.2 billion), dividing by the load growth assumed by CIF (2,557 MW), and using its new 11.2 percent carrying charge, it would have produced an avoided distribution cost of $315/kW-year. That value may be high, since ICF has not netted out retirements or otherwise account for replacement investments and may have overstated the load-related portion of distribution investments.

AESC 2018 recognizes the challenges associated with estimating avoided transmission and distribution costs (see section 10.1). In particular, it is difficult to neatly divide load related projects and accounts into load-related and non-load related categories. To that point, the ICF approach (and the AESC 2018 authors' commentary about the approach) illustrate the inherent challenges of estimating avoided transmission and distribution estimates. It is likely that different, reasonable analysts and approaches would result in different estimates (as illustrated in the previous paragraph). The AESC 2018 authors recommend some options for Eversource to consider in the future, but also recognize the separate approach used by Eversource to estimate avoided transmission and distribution, given the complexities of this type of analysis (including the choice of data sets, the approach used, as well as the professional judgement of the Eversource and ICF analysts).

10.3. Avoided PTF Costs

All load in New England pays for Pool Transmission Facilities, in addition to local facilities in the local networks. ISO New England provides regular updates to a spreadsheet of Transmission Cost Allocation (TCA) applications and decisions, listing the transmission owner, a description of the project, total cost, the portion of cost for which PTF treatment proposed by the owner, any adjustment by the ISO, and other information. The most recent version of the TCA spreadsheet includes projects filed in 2004 through 2017, totaling about $13 billion, of which $11.8 billion were included as PTF. Including inflation from the project in-service date, the PTF cost is also about $13 billion in 2018$. Removing several categories of projects—rebuilding failing or outdated equipment, relocation, addition of breakers, and the entire SWCT project (which may have been required by load levels well before 2004)—leaves $6.7 billion in load-related investments in substations, new lines, voltage upgrades, and additional capacitors and transformers.

Total load growth from the actual 2002 peak load (24,590 MW) to the current forecast of the 2024 net peak load (26,176 MW) is 1,546 MW.[215] However, some of the transmission facilities were planned when load growth was much higher; the 2006 forecast for 2015 was 31,895 MW, 7,305 MW higher than

[214] The 11.2 percent rate is close to National Grid's 11.7 percent and UI's 11.3 percent for distribution substations; UI computes a 13.4 percent rate for distribution feeders.

[215] The cost data start in 2004, but we included the load growth from 2002 to 2004 to reflect the possibility that some post-2004 projects were required by earlier load growth. Some projects may have been delayed due to uncertainty in market structure following restructuring in the late 1990s.

the 2002 peak. Dividing the load-related investment by the maximum possible load growth that might have motivated construction of those projects results in an investment per kilowatt of $916/kW.[216]

This avoided investment value must be converted to an annual value. United Illuminating provided a detailed analysis of carrying charge rates. With UI's assumptions (including Federal income tax rate of 35 percent, state income tax rate of 7.5 percent, O&M and insurance totaling about 1 percent of capital, 3 percent property tax, 45-year transmission line life, and a 2 percent inflation rate), the real-levelized carrying charge is 10.6 percent. Updating the Federal income tax rate to 21 percent reduces the carrying charge to 10.3 percent. The annualized avoided cost is thus $916/kW times 10.3 percent, or $94/kW-year in 2018 dollars.

That value should be applied to the reduction in summer peak load, which appears to dominate ISO New England's transmission planning. Utilities that use the avoided PTF costs should include only local transmission investments (those not eligible for PTF treatment) in their own avoided transmission analyses.

[216] Given a load-related investment of $6.694.7 million, and a maximum possible load growth of 7,305 MW.

11. Value of Improved Reliability

This chapter reviews of the value of energy efficiency for increasing reliability. This chapter is new to AESC 2018. This review has three parts:

- a literature review of the value of lost load,
- estimation of the value of increased generation reliability due to lower loads and higher reserve margins, and
- a review of the available data on T&D outages and whether the effect of load on outage rates can be determined from those data.[217]

Section 11.1 describes the result of our literature review.

Section 11.2 provides estimates for the value of generation reliability that is not captured in existing energy and capacity markets. To the extent that load reductions increase reserve margins, reliability will improve as market capacity charges decline.

As discussed in Section 11.3, we cannot quantify the effects of load levels on T&D reliability measures. Reliability of deliverability through the T&D system is affected by a multitude of factors, including various types of weather (e.g., ice, wind), human error (e.g., vehicle collisions, inadvertent excavation of underground cables), vegetation (contact with standing trees, impacts from falling branches), and equipment failure (from load and/or age). Load-related stresses (e.g., insulation degradation, line sag) may increase the likelihood of equipment failure and some of the other outage causes. The available data did not allow us to quantify such impacts.

This issue is new in AESC 2018. AESC 2015 and earlier version did not attempt to quantify this benefit of lower load. Reducing electric loads can improve reliability in several ways, which differ

Reliability Metrics

SAIDI (System Average Interruption Duration Index):

The average outage duration per customer served per year.

SAIDI = "Sum of all customer outage durations" /"Total # of customers served"

SAIFI (System Average Interruption Frequency Index):

The average number of outages per customer served per year.

SAIFI = "Total # of customer outages" /"Total # of customers served"

CAIDI (Customer Average Interruption Duration Index):

The average outage duration for each customer that experienced an outage per year.

CAIDI = "Sum of all customer outage durations" /"Total # of customer outages" = "SAIDI" /"SAIFI"

LOLH (Loss of Load Hourly):

The expected number of hours in a year in which there will be an outage (hours/year).

LOEE (Loss of Energy Expected):

The expected energy not supplied due to outages per year (MWh/year).

LOEE = (Energy not supplied due to an outage) × (Probability of an outage) × (Time of outage)

LOLE (Loss of Load Expectation):

The expected number of days per year that there will be an outage. A common target for LOLE is 1 day/10 years.

[217] Logically, similar considerations would apply to the reliability of natural gas supply by LDCs. Reduction in firm loads would make it less likely that a combination of extreme weather and equipment outages would result in a shortage of gas supply to New England. The 2018 AESC process did not identify any process or data that might lead to quantifying the value of natural gas reliability or the effect of gas demand on the reliability of gas delivery.

among generation, transmission, and distribution. This chapter addresses the effect of increased reserve margins based on generation reliability, the potential and obstacles in estimating the effect of load levels on T&D overloads and outages, and the value of lost load. It then develops estimates of the value of increased generation reliability per kilowatt of peak load reduction.

We estimate that the 15-year levelized benefit of increasing generation reserves through reduced energy usage is $0.65/kW-year for cleared resources and $6.60/kW-year for uncleared load reductions.

11.1. Value of Lost Load

One important issue in determining the value of energy efficiency-induced reliability is whether any reliability improvements can be quantified in dollar values. The value of lost load (VoLL) describes the cost to consumers of being unable to take power from the system. VoLL is not a single value, since the cost of an outage varies with such factors as the type of customer and the length of the outage.

We have identified four basic approaches to estimate the VoLL: (1) willingness-to-pay (WTP) estimates from survey data, (2) direct damage-cost estimates, (3) revealed preference, and (4) macroeconomic production-function techniques from aggregate economic data.[218]

Willingness-to-pay surveys use either open-ended questions asking customers how much they would be pay to avoid an outage (or be compensated for accepting an outage), or conjoint analysis, which forces the respondents to select from a series of possible values. The conjoint method may reduce bias in the open-ended survey responses, by presenting pre-defined value ranges for each sector, and may improve response rate.

Direct damage cost estimates include such effects as spoiled food, lost wages, lost revenues by commercial customers, lost product for industries, theft and damaged equipment. Indirect damages include costs that are harder to quantify (and must be determined from survey responses), such as inconvenience and damaged customer confidence.

Revealed-preference approaches attempt to estimate the value to the customer through some monetized alternative transaction, such as purchase of backup generation to avoid outages. This method is particularly applicable to commercial and industrial customers.

Macroeconomic production-function techniques, also referred to as lost productivity estimation, estimate the value of outages by assuming a linear relationship between economic output (such as GDP)

[218] For those interested in more detail, Schroder and Kuckshinrichs (2015) provide a review of the various methods used to assess consumer values for reliability and of the direct and indirect costs that those methods attempt to value.

and energy consumption.[219] We have identified only one lost-productivity analysis of VoLL used to estimate commercial and industrial VoLL, authored by London Economics in 2012.[220]

Table 92 provides the range of values in $/kWh identified from our literature search on VoLL.[221] Most studies are WTP estimates.[222]

Table 92: Reported values of lost load in $2018/kWh

Report Year	Author	Region	Small C&I	Large C&I	Residential	Average across sectors
2015	LBNL (Sullivan, et al)	US	$280	$16	$2	
2014	London Economics (2012)	US	$46	$31	$2	
2014	London Economics (2012)	ERCOT	$7	$4		$10
2012	USAID (NZ)	New Zealand	$33	$84	$12	$44
2012	USAID (IE)	Ireland	$4	$11	$19	$10
2012	USAID (AU)	Australia	$11	$31		$50
2012	USAID (AT)	Austria			$2	$7
2012	USAID (NL)	Netherlands			$25	$6
2010	Centolella	Midwest	$56	$28	$5	

Note: The highlighted study is a lost-productivity analysis of VoLL.

The range of the values in Table 92 is not surprising. The values will vary due to outage duration, recent customer experiences with outages, location, and customer mix within the customer sectors. The results will also depend on the details of the survey or analysis. Various studies divide commercial and industrial (C&I) customers into "small" and "large" categories using a range of cut-off points, contributing to the variation in the ratio reported VoLL between those classes. The VoLL for C&I customers would be expected to vary widely among types of business, as well as with the availability of backup power. Figure 43 and Figure 44 provide estimates of the variability of VoLL within and between industry categories for

[219] Khuzadze, S., Delphia, J. A Study of the Value of lost Load for Georgia. Report prepared for USAID Hydro Power and Energy Planning Project. Deloitte Consulting, LLP. (2014) https://dec.usaid.gov/dec/content/Detail.aspx?ctID=ODVhZjk4NWQtM2YyMi00YjRmLTkxNjktZTcxMjM2NDBmY2Uy&rID=MzQ5MTg3; London Economics "Estimating the Value of Lost Load" Briefing paper prepared for the Electric Reliability Council of Texas. (2013).

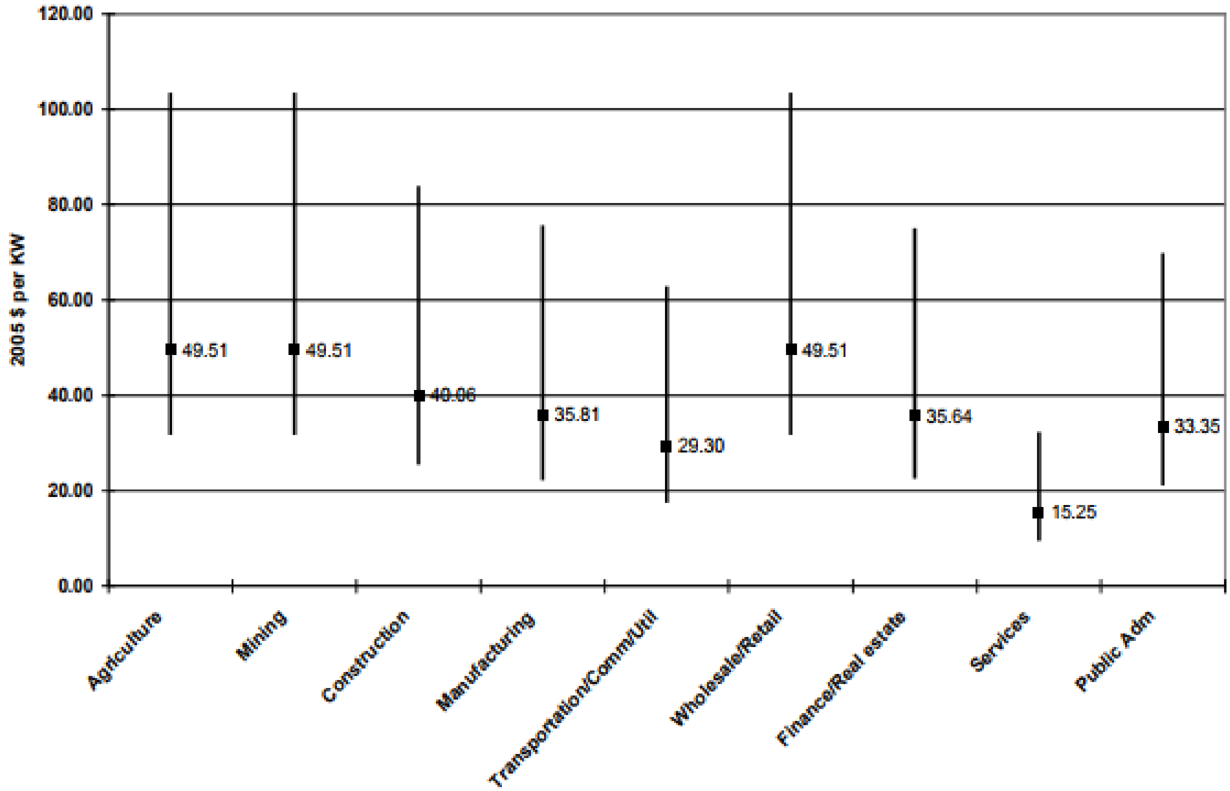
[220] The reported VoLL for commercial and industrial customers in ERCOT that are reported by London Economics, Inc use the lost production function method. The reported VoLL for residential (ERCOT) is not based on GDP; just average rate, which understates the value to customers.

[221] Other studies report a cost per event, but do not convert that value into cost per kWh.

[222] The London Economics study used the production function method to estimate VoLL for commercial and industrial customers located in ERCOT. This study did not use a similar method based on GDP for valuing residential VoLL; just the average tariff rate, which understates the value to customers.

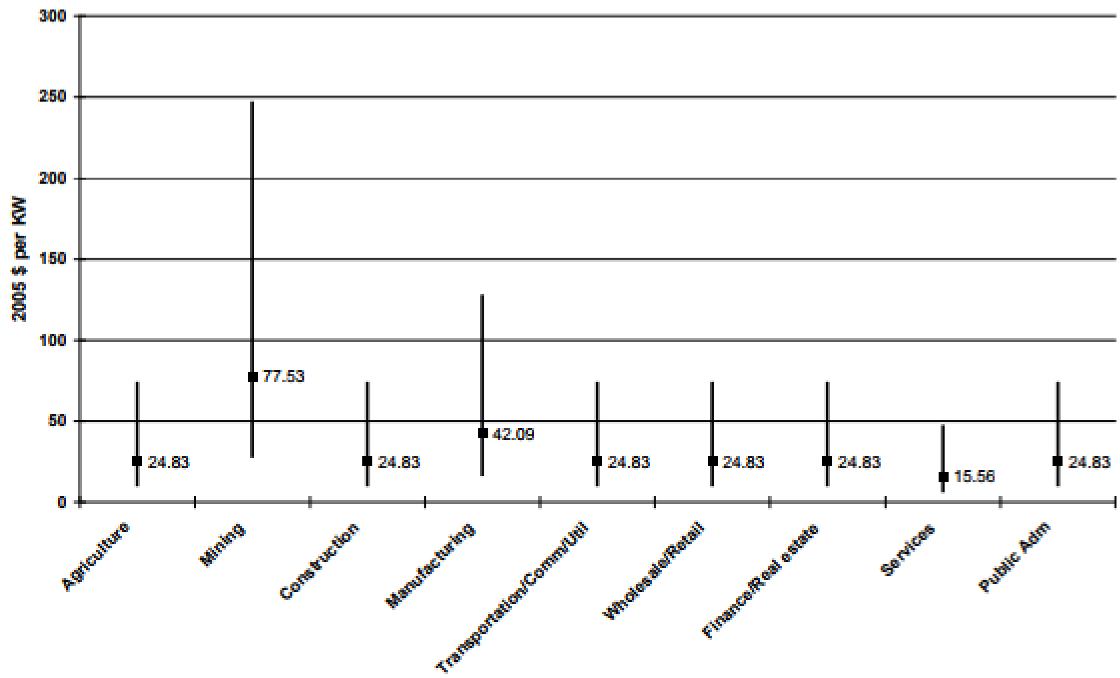
large and small non-residential customers.[223] Regardless of the accuracy of the specific values in those figures, they represent the uncertainty and variability in VoLL estimates.

Figure 43. VoLL estimates by large C&I sector (one-hour duration)



[223] Centolella, P., M. Farber-DeAnda, L. Greening, and T. Kim. 2010. Estimates of the Value of Uninterrupted Service for the Mid-West Independent System Operator. Prepared by SAIC for Mid-West Independent System Operator. Available at: https://sites.hks.harvard.edu/hepg/Papers/2010/VOLL%20Final%20Report%20to%20MISO%20042806.pdf.

Figure 44. VoLL estimates by small C&I sector (one-hour duration)



The most comprehensive studies of reliability value are the meta-analyses conducted by Lawrence Berkeley National Laboratories (LBNL) beginning in 2003, with updates and additions in 2004, 2009, and 2015. The most recent study includes 38 utilities and roughly 25,000 survey responses from customers. Table 93 reproduces the findings from the 2015 report, by customer type and outage duration.

Table 93. VoLL results, LBNL 2015 (in 2013$)

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165,482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Source: Sullivan, M.J., Schellenberg, J., Blundell, M., Nexant, Inc. "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Berkeley: LBNL, 2015. LBNL-6941E. https://emp.lbl.gov/sites/all/files/lbnl-6941e.pdf.

These estimates of the costs of unserved energy for outages of one to four hours (typical of generation capacity shortfalls) on the order of $2/kWh for residential, $17/kWh for large C&I, and $250/kWh for small C&I.

The LBNL studies found that the assessed reliability values increase as the duration increases in all of its cases. Up to about four-hour outages, the relationship is less than linear, so the cost per kWh decreases. For longer outages, the valuation is more nearly linear. In general, the VoLL estimates per kWh are lowest for residential, higher for large non-residential, and highest for small non-residential customers.[224]

The average monthly use per customer in the LBNL study is about 900 kWh for residential customers, 1,600 kWh for small C&I, and 590 MWh for large C&I. The definition of small C&I varies widely; the LBNL customers are at the small end of the range. No standard report provides data for this breakout of sales.[225]

LBNL's definition of small non-residential customer is a little larger than the aggregation of Eversource's Eastern Massachusetts tariffs labelled G0, G1 and T1, which have an average monthly usage of 1,167 kWh and comprise 13 percent of non-residential sales. These customers are much smaller on average than WMECo's G-0 rate, which has an average usage of 2,258 kWh and comprises 27 percent of non-residential sales. Interpolating between those two utilities suggests that the LBNL small non-residential customers (at 1,600 kWh/month) account for about 18 percent of non-residential sales. National Grid Massachusetts G-1 customers have an average monthly use of about 1,300 kWh and comprise 17 percent of non-residential sales, which is very close to the Eversource data.

We have used the sector representation ratios found in New England to adjust the LBNL sectoral findings. New England-wide, residential customers make up about 40 percent of sales. Of the 60 percent that is non-residential, about 17 percent or 18 percent would fall in the LBNL "small" category, so that group would be about 10 percent of sales and large non-residential about 50 percent.

The next question is what length of outage shown be assumed for estimating VoLL. The value of increased generation reserves results from reducing the frequency of events in which the ISO would shed load due to insufficient generation resources. Generation shortages may be alleviated by (among other options) bringing additional generation on line, which may take hours; by the decline in load after the daily peak; or increasing imports from other regions. The outage for a particular area may end when the ISO sheds load in another area, sharing the burden in rolling blackouts. In the case of a regional blackout, restarting generators and restoring supply would likely take many hours.

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[224] The cost per outage per customer may be largest for the large C&I, since they may use (and hence lose in the outage) many times as much energy as the small C&I customers.

[225] FERC Form 1 sales by tariff include only full-service customers, and EIA reports use much broader definitions of small non-residential customer, or disaggregate non-residential loads between commercial and industrial, rather than size.

For load-related transmission and distribution outages, durations can range from momentary to over a day, depending on the nature of problem and whether it can be resolved by resetting or reconfiguring equipment (such as switches and breakers) or requires repair, reconstruction, or replacement of major equipment. As explained below, we cannot yet quantify the effect of load of T&D outages, so it would be premature to determine the duration of outages for pricing purposes.

Table 94 shows the average of the 1-, 4-, 8- and 16-hour outages for each class per kWh, as a proxy of the mix of generation-driven outages.[226] Generation-precipitated outages are unlikely to be much less than one hour.

Table 94. Average estimates of VoLL outages of 1 to 16 hours (2018 $/kWh)

Class	VoLL in $/kWh	Assumed % of New England Energy
Residential	$2	40%
Large C&I	$16	50%
Small C&I	$280	10%
Average	$37	

We also computed a very simple application of the production function technique to estimate the value of reliability as the ratio of annual state GDP to annual energy consumption.[227] This method implicitly assumes that every kWh of energy delivered has the same economic value to the New England economy and that unserved energy has no other costs. In fact, a few hours of service interruption may destroy days' worth of product and have costs not reflected in GDP, such as aggravation and health problems.

Table 95 shows the ratio of 2015 state level GDP to total commercial and industrial energy consumption, for each New England state and averaged over the region.[228] New England GDP continues to rise, while electricity consumption falls, so the ratios will be higher in 2017 and (most likely) later years.

[226] Average values reported in Table 94 have been calculated by Resource Insight, Inc., based on the values reported by Sullivan, 2015 (see Table 93).

[227] The computation of the VoLL from average GDP per kWh of consumption is defined by Khujadze, S., Delpyhia, J. *"A Study of the Value of Lost Load (VOLL) for Georgia"*. (2014) https://dec.usaid.gov/dec/content/Detail.aspx?ctID=ODVhZjk4NWQtM2YyMi00YjRmLTkxNjktZTcxMjM2NDBmY2Uy&rID=MzQ5MTg3

[228] The GDP data are from the Bureau of Economic Analysis (https://www.bea.gov/iTable/index_regional.cfm) and the retail sales values are from the EIA (https://www.eia.gov/electricity/data/eia861m/xls/retail_sales_2017.xlsx).

Table 95. Ratio of 2015 GDP to energy usage (2018$/kWh)

State	GDP/kWh
MA	$15.15
CT	$8.98
RI	$7.60
VT	$5.70
NH	$7.05
ME	$5.00
New England, weighted average	**$11.63**

This macro-economic analysis produces aggregate results about a third of those of the LBNL survey, resulting in a lower bound, given the differences in methodology. We use VoLLs of $12/kWh and $37/kWh in the subsequent analysis, representing the range of plausible values.

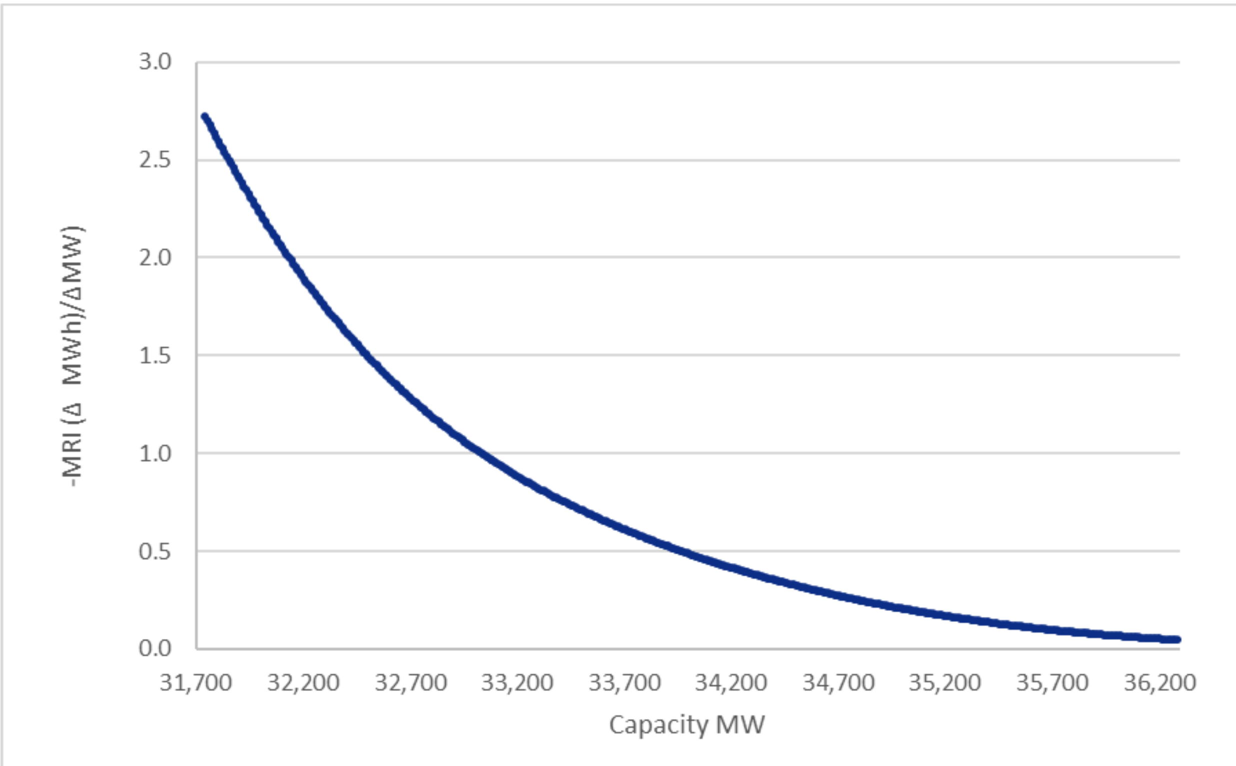
11.2. Value of Reliability: Generation Component

To the extent that load reductions increase reserve margins, reliability will improve, in addition to the reductions in market charges. Load reductions can improve generation reserves in at least four ways:

- The ISO New England forward capacity auctions are designed to increase the amount of capacity acquired as the price falls. To the extent that energy efficiency programs reduce the capacity clearing price, reserve margins and reliability will increase.
- Lower capacity market prices will result in some additional supply resources not clearing in the FCA. Some of those resources will retire, but others will continue to operate as energy-only resources, adding to available reserves. While not obligated to do so, these resources are likely to operate at times of tight supply and high energy prices.
- Under the ISO New England CASPR program, new resources supported by state mandates (Canadian imports, offshore wind, and at least some solar capacity) will not be able to participate in the FCA, as explained in the previous section on avoided capacity costs. With lower load, this fixed quantity of non-cleared capacity will represent a greater contribution to percentage reserves and to reliability.
- Some energy efficiency measures will reduce load before they are recognized in the capacity market, either as cleared resources or as reductions to the load forecast. By reducing load but not affecting the amount of other cleared capacity, those load reductions will increase reserve margins.

ISO New England has developed estimates of the marginal reliability index (MRI) in the process of constructing the administrative demand curve estimates for FCAs 11 and 12.[229] The MRI is the change in loss of energy expectation (LOEE) in MWh, for each additional MW of available capacity or reserve margin.[230] At the ISO's targeted loss of load expectation (LOLE) of 0.1 days/year (one day in ten years), the estimated MRI is 0.602. As the reserve margin increases, the MRI declines, as shown in Figure 45.

Figure 45. ISO New England MRI curve for FCA 12



If FCA 12 ends at the $5.30/kW-month price of FCA 11, about 34,675 MW would clear and the FCA 12 MRI curve indicates that the MRI would be -0.28.[231]

[229] The ISO provided the MRI values in the demand curve spreadsheets for recent FCAs and ARAs, including "2021-2022 CCP Forward Capacity Auction MRI Demand Curves," https://www.iso-ne.com/markets-operations/markets/forward-capacity-market. MRI is inherently negative (since it is the change in outage hours per MW of capacity); ISO New England generally presents the results as -MRI, so that the value is positive.

[230] The ISO simplifies the MRI units from (MWh/year)/MW to hours/year, which is technically correct but potentially non-intuitive.

[231] MRI is inherently negative (since it is the change in outage hours per MW of capacity); ISO New England generally presents the results as -MRI, so that the interpretation of the marginal reduction is positive (improvement in reserve available).

Table 96 summarizes the values per kW-month for increased reserve capacity, resulting from multiplying the two estimates of the VoLL by the FCA 12 MRIs at various clearing prices, with the corresponding reserve margins.

Table 96. Reliability value for cleared capacity along FCA 12 supply curve(2018 $/kW-month)

FCA Clearing Price ($/kW-mo)	Reserve Margin	–MRI	$/kW-month Reliability Value at VoLL =	
			$12/kWh	*$37/kWh*
$11.02	13.1%	0.825	$0.83	$2.54
$9.96	13.6%	0.745	$0.75	$2.30
$9.00	14.1%	0.673	$0.67	$2.08
$7.98	14.6%	0.597	$0.60	$1.84
$6.99	16.5%	0.389	$0.39	$1.20
$5.99	17.3%	0.322	$0.32	$0.99
$4.99	18.1%	0.263	$0.26	$0.81
$3.99	18.8%	0.212	$0.21	$0.65
$2.99	19.6%	0.169	$0.17	$0.52

Table 97 summarizes the value per kilowatt-month for the clearing prices and reserve margins forecast in Chapter 5.

Table 97. Value of generation reliability improvement ($/kW-month 2018$)

Summer	FCA	Clearing Price 2018$	Reserve Margin	*-MRI*	$/kW-month Reliability Value at VoLL =	
					$12/kWh	*$37/kWh*
2018	9	$9.81	1.168	0.570	$0.57	$1.76
2019	10	$7.28	1.198	0.423	$0.42	$1.30
2020	11	$5.35	1.221	0.152	$0.15	$0.47
2021	12	$4.74	1.181	0.263	$0.26	$0.81
2022	13	$4.84	1.180	0.270	$0.27	$0.83
2023	14	$4.94	1.179	0.275	$0.28	$0.85
2024	15	$5.22	1.177	0.293	$0.29	$0.90
2025	16	$5.65	1.173	0.322	$0.32	$0.99
2026	17	$6.13	1.169	0.353	$0.35	$1.09
2027	18	$6.60	1.165	0.389	$0.39	$1.20
2028	19	$7.07	1.149	0.558	$0.56	$1.72
2029	20	$7.54	1.146	0.597	$0.60	$1.84
2030	21	$6.60	1.165	0.389	$0.39	$1.20
2031	22	$7.07	1.149	0.558	$0.56	$1.72
2032	23	$7.54	1.146	0.597	$0.60	$1.84
2033	24	$6.60	1.165	0.389	$0.39	$1.20
2034	25	$7.07	1.149	0.558	$0.56	$1.72
2035	26	$7.54	1.146	0.597	$0.60	$1.84

Subject to regulatory review, the program administrators should add a value of reliability to the avoided costs for screening. The reliability effect of cleared energy efficiency load reductions will be partially offset by reduction in the amount of other capacity cleared, as shown in Table 98, while uncleared load reductions will not be subject to such offsets. Both cleared and uncleared reliability values will be subject to decay, proportional to the reduction. Table 98 shows the value of reliability, in $/kW-year, for a VoLL of $25/kWh (the middle of the range), for cleared resources. Table 99 provide the same information for uncleared load reductions.

Table 98. Value of reliability improvement from cleared resources (2018$/kW-year)

Summer	VoLL per kW *$/kW-year*	Q shift %	Offset from Rebound			Reliability Value of Cleared EE ($/kW-year)		
			2018	*2019*	*2020*	*2018*	*2019*	*2020*
2018	$14.25	37%	0%			$5.32		
2019	$10.58	24%	17%	0%		$2.15	$2.59	
2020	$3.80	37%	33%	17%	0%	$0.94	$1.16	$1.40
2021	$6.58	8%	50%	33%	17%	$0.27	$0.36	$0.44
2022	$6.75	8%	67%	50%	33%	$0.18	$0.27	$0.36
2023	$6.88	8%	83%	67%	50%	$0.10	$0.19	$0.29
2024	$7.33	8%	100%	83%	67%		$0.10	$0.19
2025	$8.05	95%		100%	83%			$1.30
2026	$8.83	95%			100%			
15-year levelized (2018-2032)						**$0.65**	**$0.33**	**$0.27**

Table 99. Value of reliability improvement from uncleared load reductions ($2018/kW-year)

Summer	VoLL per MW *$/kW-year*	Q shift %	Not Reflected in Load Forecast			Offset from Rebound			Reserve Margin	Reliability Value of Uncleared EE ($/kW-year)		
			2018	*2019*	*2020*	*2018*	*2019*	*2020*		*2018*	*2019*	*2020*
2018	$14.25	37%	100%			0%			1.168	$16.64		
2019	$10.58	24%	100%	100%		0%	0%		1.198	$12.67	$12.67	
2020	$3.80	37%	100%	100%	100%	0%	0%	0%	1.221	$4.64	$4.64	$4.64
2021	$6.58	8%	100%	100%	100%	0%	0%	0%	1.181	$7.77	$7.77	$7.77
2022	$6.75	8%	100%	100%	100%	0%	0%	0%	1.180	$7.97	$7.97	$7.97
2023	$6.88	8%	70%	100%	100%	0%	0%	0%	1.179	$5.88	$8.11	$8.11
2024	$7.33	8%	50%	70%	100%	5%	0%	0%	1.177	$4.64	$6.24	$8.62
2025	$8.05	95%	30%	50%	70%	13%	5%	0%	1.173	$8.28	$8.98	$9.30
2026	$8.83	95%	10%	30%	50%	25%	13%	5%	1.169	$7.63	$9.02	$9.79
2027	$9.73	94%	0%	10%	30%	40%	25%	13%	1.165	$6.41	$8.35	$9.89
2028	$13.95	94%		0%	10%	57%	40%	25%	1.149	$6.54	$9.02	$11.77
2029	$14.93	94%			0%	73%	57%	40%	1.146	$4.27	$6.95	$9.59
2030	$9.73	94%				85%	73%	57%	1.165	$1.60	$2.86	$4.64
2031	$13.95	94%				93%	85%	73%	1.149	$1.01	$2.26	$4.02
2032	$14.93	94%				98%	93%	85%	1.146	$0.27	$1.07	$2.40
2033	$9.73	94%				100%	98%	93%	1.165		$0.18	$0.72
2034	$13.95	94%				100%	100%	98%	1.149			$0.26
2035	$14.93	94%				100%	100%	100%	1.146			
15-Yr Levelized										**$6.60**	**$6.44**	**$6.51**

11.3. Value of Reliability: T&D Component

Reducing loads provides a number of benefits to the T&D system. Lower loads reduce acute overloads, by allowing additional capacity in transmission and distribution facilities to accommodate normal peak flows, as well as power transferred from facilities that are forced out of service by non-load-related problems. Reduced loading on high-load days and hours also mitigates the overheating of system equipment. That overheating leads to deterioration of insulation in transformers and underground lines, which may in turn, cause equipment failure (faults and fires), as well as sagging and annealing of overhead lines, which can lead to mechanical failure while under stress (e.g., high wind, ice, tree contact). Reducing loads can also reduce overloads and violations of transmission planning standards, by leaving additional capacity in transmission facilities to accommodate flows from facilities that are forced out of service by non-load-related problems.[232]

The effects of load on T&D failures is complex and often indirect. While the effects on individual pieces of equipment are well documented, no comprehensive analysis appears to have been conducted on the utility scale. For example, we know how much a transformer's operating life is degraded by a given number of hours at a particular overload after a day of carrying a specified load factor, but not the frequency of occurrence for those events for typical distribution systems.

We have not been able to locate any literature on the relationship between load and T&D reliability, even though engineering fundamentals indicate that such a relationship must exist. T&D problems will result in momentary outages, as well as longer outages. Not all T&D problems are affected by load levels: if a branch falls on a distribution feeder, the fault will impact downstream customers regardless of the loading on the line. Lower load levels will reduce the frequency of transformer failures and underground line due to heat build-up and insulation breakdown, and due to overheat line failure due to heat buildup, sag, and (in some cases) insulation degradation. Lower loads also increase the probability that a back-up facility (another transformer at the same substation, a looped feeder) can pick up all or most of the load dropped.

An hour of outage region-wide would be over 14 million kWh annually; at an average cost of $200/kWh, that would be worth $2.8 billion dollars, or about $25/MWh delivered. If load is responsible for 10 percent of that value, each MWh of energy saved would reduce T&D outage costs by $2.5, which is not enormous but not trivial. This benefit would apply to whatever percentage of the T&D system does not experience avoided equipment additions due to the energy efficiency program.

The value of increased T&D reliability is complementary, not duplicative, of the avoided T&D costs. Reducing loads (or avoiding rising loads) will tend to increase reliability where the T&D system does not change; where T&D equipment is avoided by a load reduction, reliability for that T&D element (e.g., distribution substation, feeder, line transformer, secondary lines) is not likely to improve.

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[232] Transmission planning typically considers the effects of various combinations of contingencies (equipment failures) under various load and generation scenarios, without estimating the frequency of the contingencies or scenarios.

Recognizing that load-related failures may not occur at peak loads, AESC 2018 investigated data on outages and load levels. All six states require utilities to file reliability reports; we have examined the reports shown in Table 100.

Table 100. Utility reliability reports reviewed

State	Reliability Report Title	Utilities
NH	Reliability Enhancement Plan and Vegetation Management Plan	Liberty Eversource (PSNH) Unitil
ME	Annual Power System Reliability Report	Emera Maine Central Maine Power
RI	Electric Infrastructure, Safety, and Reliability Plan, 2015 System Reliability Procurement Report	National Grid (Narragansett Electric)
MA	Service Quality Reports	Eversource (NSTAR, Western MA) National Grid
VT	Service Quality and Reliability Plan	Green Mountain Power
CT	Transmission and Distribution Reliability Report (TDRP)	Eversource (CL&P) Avangrid (United Illuminating)

In these reliability reports, utilities provide annual or quarterly reports on traditional reliability metrics, such as SAIDI, SAIFI, and CAIDI. The detailed data for the Rhode Island report are not publicly available, and the level of detail in the other reports vary. The Massachusetts filings provide the most comprehensive data, including causes of outages and circuit-level loading and reliability measures.

Figure 46 plots the SAIDI of each National Grid Massachusetts feeder against the peak loading on the feeder in 2014 to 2016 (each dot represents one circuit for one year), as a percentage of the feeder's normal rating. Figure 47 provides the same information for circuit SAIFI.

Figure 46. 2014–2016 SAIDI by feeder, National Grid MA

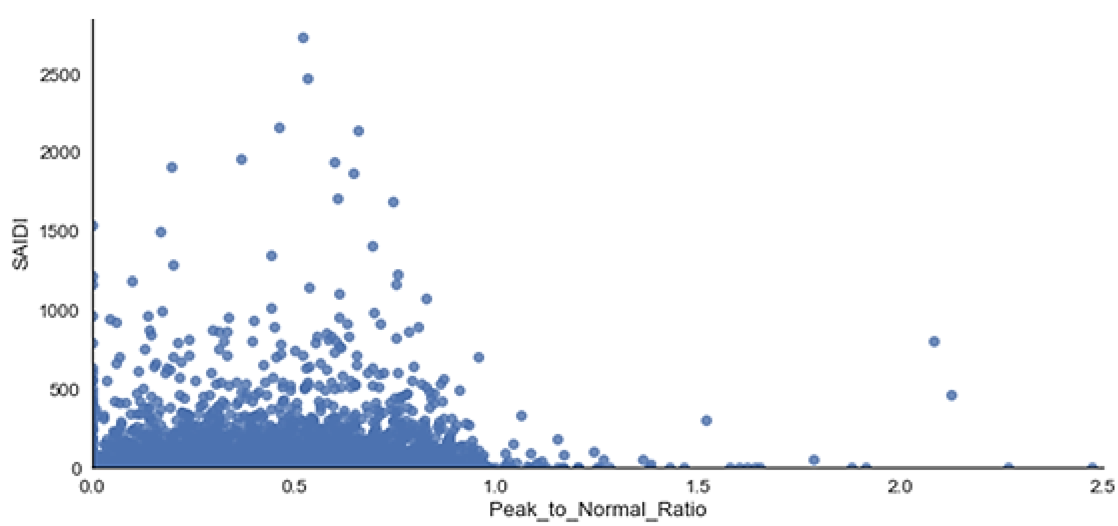
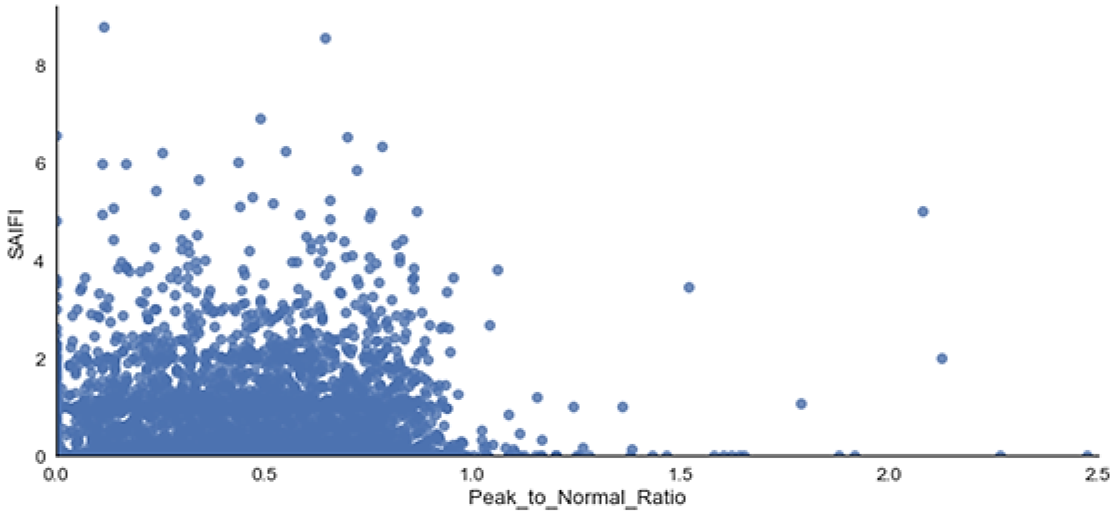


Figure 47. 2014–2016 SAIFI by feeder, National Grid MA



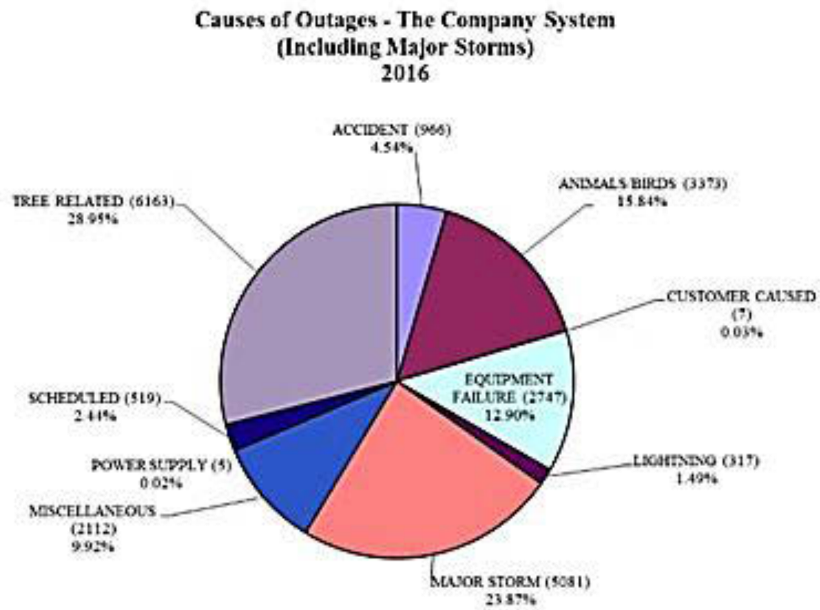
The data do not show any clear relationship to changes in failure rate as a function of feeder loadings. This lack of a trend probably results from two facts:

- most outages are due to tree contacts, animals, and other non-load-related causes, and
- the stress on and deterioration of the equipment is cumulative and is a function of loading throughout the year and in previous years, not just the peak load.

Reliability on the T&D system is affected by a multitude of reasons—weather related, human error, fallen trees, equipment failure, and even unknown reasons. Several of these outage-related causes may be exasperated by load-related stresses that are not accounted for. An equipment failure may occur because load has grown and the system is overworked. Further, power quality issues can be affected by load and may be recorded as unknown.

Eversource (CT) filed Figure 48 in its 2017 TDRP, identifying overloads as accounting for approximately 2 percent of outages and equipment failure (which may be accelerated by load) accounting for 12.9 percent. Unfortunately, this report does not break out the overhead equipment-failure outages between poles and conductors.

Figure 48. Eversource (CT) causes of outages (2016)



Note: The number of interruptions is included in the parentheses next to each cause.

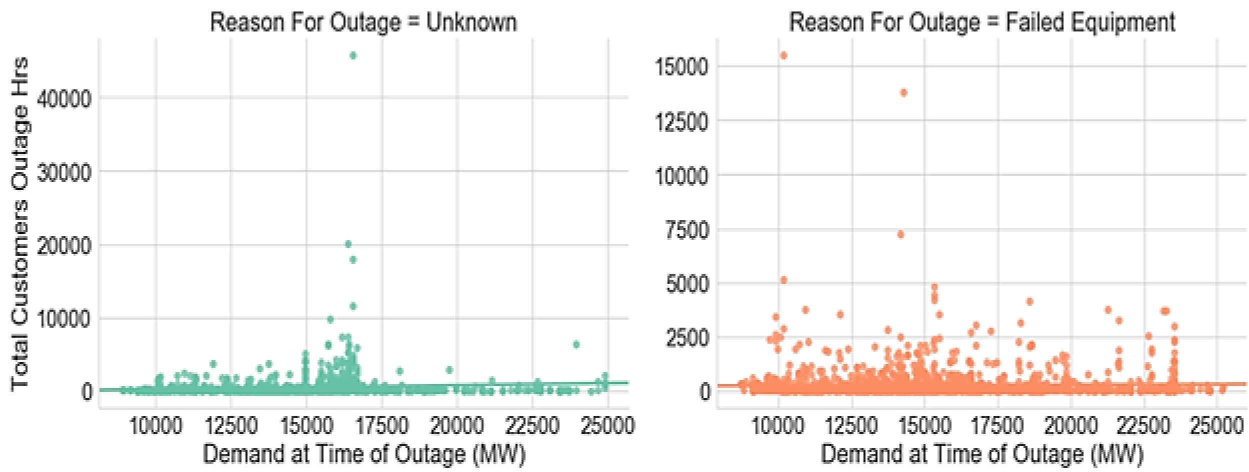
Accident	4.54%
Vehicle	3.54%
Foreign Objects	0.31%
Employee Error	0.69%

Equipment Failure	12.90%
Overhead System	5.43%
Underground Cable	0.36%
DB Cable	4.37%
Transmission	0.00%
Substation	0.05%
Transformer	2.69%
Other	0.00%

Miscellaneous	9.93%
Overload	1.60%
Other	1.63%
Unknown	6.69%

In addition to the peak loads at the circuit level, the Massachusetts utilities also provide the cause and time of each outage. Figure 49 plots the National Grid outages identified as “equipment failure” or “other” against ISO New England load. Again, no clear trend is evident, but since the high loads are rarer, it is possible that further analysis will identify a relationship, especially for the equipment failures.

Figure 49. National Grid (MA) outage hours and ISO New England load



To isolate the effect of load on the frequency of outages, we also plotted the National Grid (MA) data on number of outages as a function of the ISO New England system load, binning the outages into increments of 5 percent of the ISO peak. Figure 50 shows our results.

Figure 50. National Grid (MA) number of outages by ISO New England load percentile

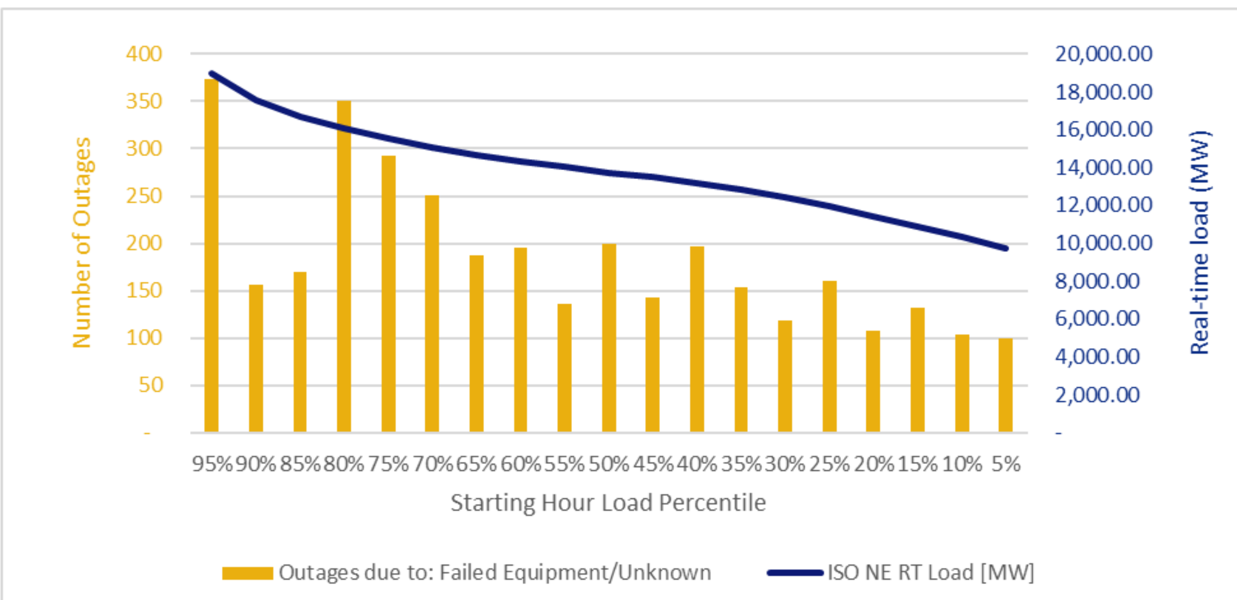


Figure 50 seems to indicate that there is at least a weak correlation between higher load and increased number of outages. While these results are suggestive, they are not clear enough to quantify a relationship of load levels on T&D outages measures.

12. Sensitivity Analysis

The following sections detail the inputs and results of the sensitivity analysis. In AESC 2018, we evaluate avoided costs under four different sensitivities (in addition to the main case, discussed above). These sensitivities include a High Natural Gas Price case, a Low Natural Gas Price case, a High Load case (representing a future with an accelerated deployment of air-source heat pumps and electric vehicles) and a With EE case (representing a future that incorporates energy efficiency).

In general, we find that the levelized energy prices and DRIPE values in the high and low gas price sensitivities correspond with the assumed differences in Henry Hub prices (i.e., the underlying difference in gas price).[233] Meanwhile, we do not observe substantial differences between levelized energy prices in the High Load sensitivity and With EE sensitivity when compared to the main AESC 2018 case. This is due in large part to the key driver of energy prices—natural gas prices—not changing between sensitivities.

For capacity prices, we find that long-term equilibrium in the With EE and High Load sensitivities oscillate between a price similar to the cost of new entry and a lower price following major additions, as in the main AESC 2018 case.

In the sensitivity with higher electricity demand, RPS compliance costs are generally higher relative to the main 2018 AESC case, reflecting an increased demand for RECs as overall demand levels rise. Likewise, in the sensitivity with lower electricity demand, RPS compliance costs are generally lower relative to the main 2018 AESC case, reflecting a decreased demand for RECs.

12.1. When to Use These Sensitivities

Two of the sensitivities (high and low natural gas prices) are modeled primarily because natural gas prices are one of the inputs to which the AESC study is historically the most sensitive. The 2018 AESC study is no exception; one of the primary reasons for the decrease in energy values between the 2015 AESC study and the 2018 AESC study is the associated decrease in annual natural gas prices. The purpose of these two sensitivities is to provide a range of potential avoided energy costs under futures in which natural gas prices prove to be different than what were selected to be modeled under the main 2018 AESC study.

The third sensitivity, modeling a future with higher levels of electricity demand, is meant to be utilized by readers of the 2018 AESC study when estimating the avoided cost impacts of measures in a future with high levels of new end-use electrification. In this sensitivity, these new end-uses come from new installations of residential heat pumps and an increased deployment of electric vehicles. Note that the

[233] Per the direction of the Study Group, we did not estimate capacity prices or RPS compliance costs under these two sensitivities.

modeled trajectories for the electrification of these two new end-uses were selected to provide a reasonable expectation of a "high electrification" future; they are not intended to represent a "most likely" or a "policy-based" future. Like the main 2018 AESC case, this future assumes no new installations of energy efficiency (or other demand-side measures) in 2018 or any later years.

The fourth sensitivity models a future in which energy efficiency measures are installed in 2018 and later years, in direct contrast to the main 2018 AESC case. The purpose of this future is to provide readers of AESC 2018 an avoided cost stream with which to measure avoided costs of measures currently excluded from program administrator energy efficiency plans.

As with the main 2018 AESC case, all four of these sensitivities should not be used to infer information about actual future market conditions, energy prices, or resource builds in New England; actual future prices will be different than the long-term prices calculated in these sensitivities as actual future prices will be subject to short-term variations in energy markets that are unknowable at this point in time.

12.2. Sensitivity Inputs

High and Low Natural Gas Price sensitivities

This section presents detail on the High and Low Natural Gas Price sensitivities. The natural gas price trajectory is both one of the most difficult assumptions to forecast and one of the primary drivers of the avoided energy cost in AESC studies.

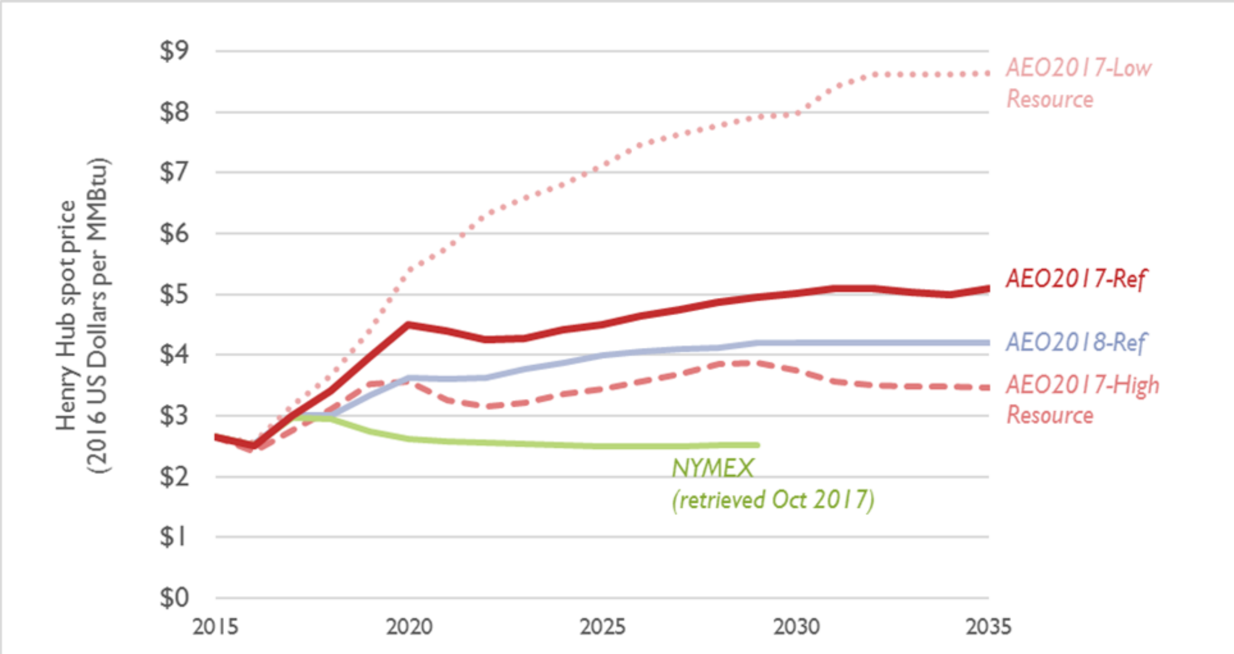
Figure 51 shows potential forecasts of Henry Hub prices using the current NYMEX futures (symbol "NG") and the three relevant cases in the AEO 2017.[234] In particular, the AESC 2018 High Natural Gas Price case will track the Henry Hub price described by the "AEO2017-Low Resource" trajectory.[235] This trajectory is based on a case modeled in the 2017 AEO, wherein a lower-than-otherwise-expected amount of extractable natural gas is assumed to be available, resulting in increased prices.[236] On a 15-year levelized basis from 2018 to 2035, the Henry Hub projection used in the High Gas Price sensitivity is 53 percent greater than the price used in the main 2018 AESC case. The Henry Hub projection used in the Low Gas Price sensitivity is 22 percent lower than the price used in the main 2018 AESC case. Likewise, Figure 51 also shows a lower Henry Hub price described by the "AEO2017-High Resource" trajectory, which is used to form the trajectory of a Low Natural Gas Price sensitivity.

[234] Source: CME. Downloaded 10/18/2017 at 4:00 PM PDT.

[235] Note that we also update the RFO and DFO prices assumed in our energy price modeling to be consistent with this trajectory.

[236] Additional detail on the drivers behind the three long-term natural gas price trajectories is available in Chapter 2.

Figure 51. Henry Hub gas price forecasts



Note: In AESC 2018, we used a combination of NYMEX futures (for the near term) and the AEO 2017 Reference case (for the long term) as our main reference points for constructing a projection for Henry Hub prices. All other prices shown in this figure are for informational purposes only. The AEO 2018 trajectory, released in February 2018 and presented here for information purposes, closely follows the Henry Hub price trajectory in the AEO 2017 Reference case, but at a price that is on average 14 percent lower in any given year through 2035.

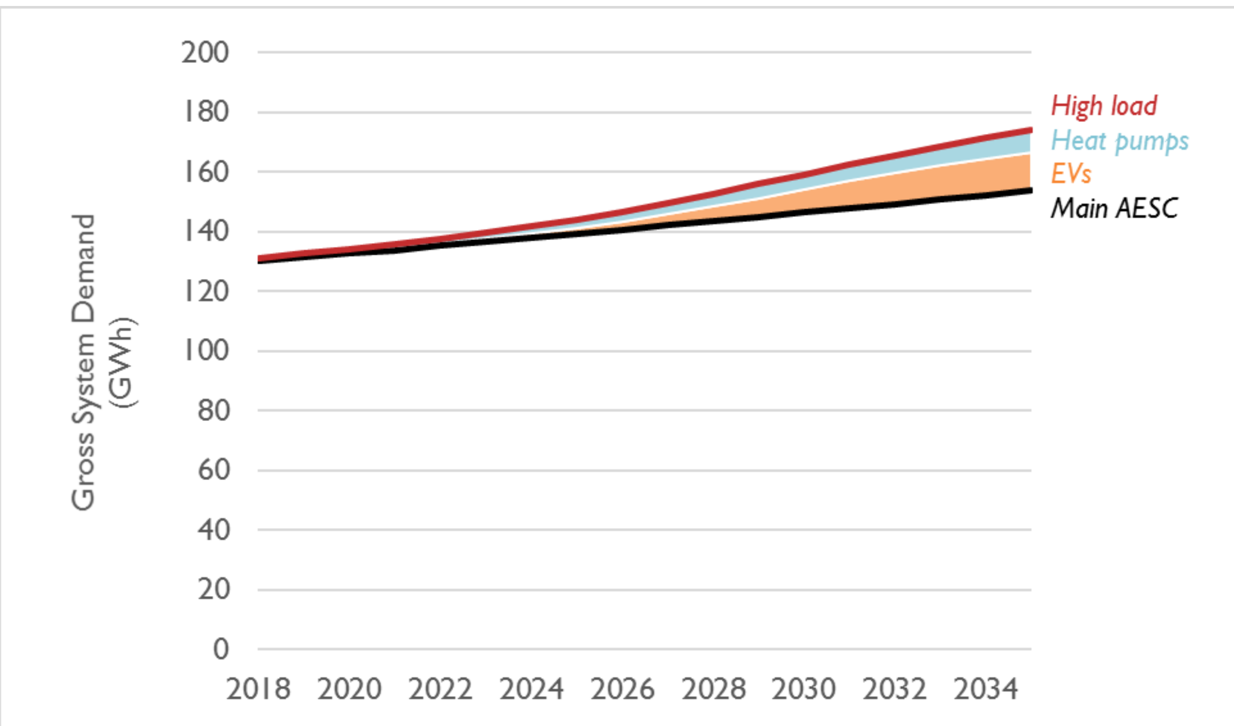
High electricity demand sensitivity

The high electricity demand sensitivity provides an estimate of avoided costs under a future in which a large number of end-uses that are currently powered by sources other than electricity are converted to electricity (i.e., "strategic electrification"). Specifically, our high electricity demand projection includes:

1. Additional electric vehicles (EVs)
2. Additional deployment of residential heat pumps

Our high electricity demand projection does not make any assumptions associated with electrifying other types of end-uses (such as electric water heating, commercial heat pumps, non-light duty vehicle electrification,[237] or industrial electrification). Note that the projection of electricity demand under the main AESC 2018 study (which is based on the econometric forecast developed by ISO New England) does not include any load associated with electric vehicle or residential heat pump deployment. Figure 52 compares the projection of annual electricity demand under the main AESC 2018 Study (i.e., a future with no incremental energy efficiency) and the high demand forecast (i.e., a future with no incremental energy efficiency and additional electrification).

Figure 52. Comparison of New England electricity projections under the 2018 AESC Study and additional electrification

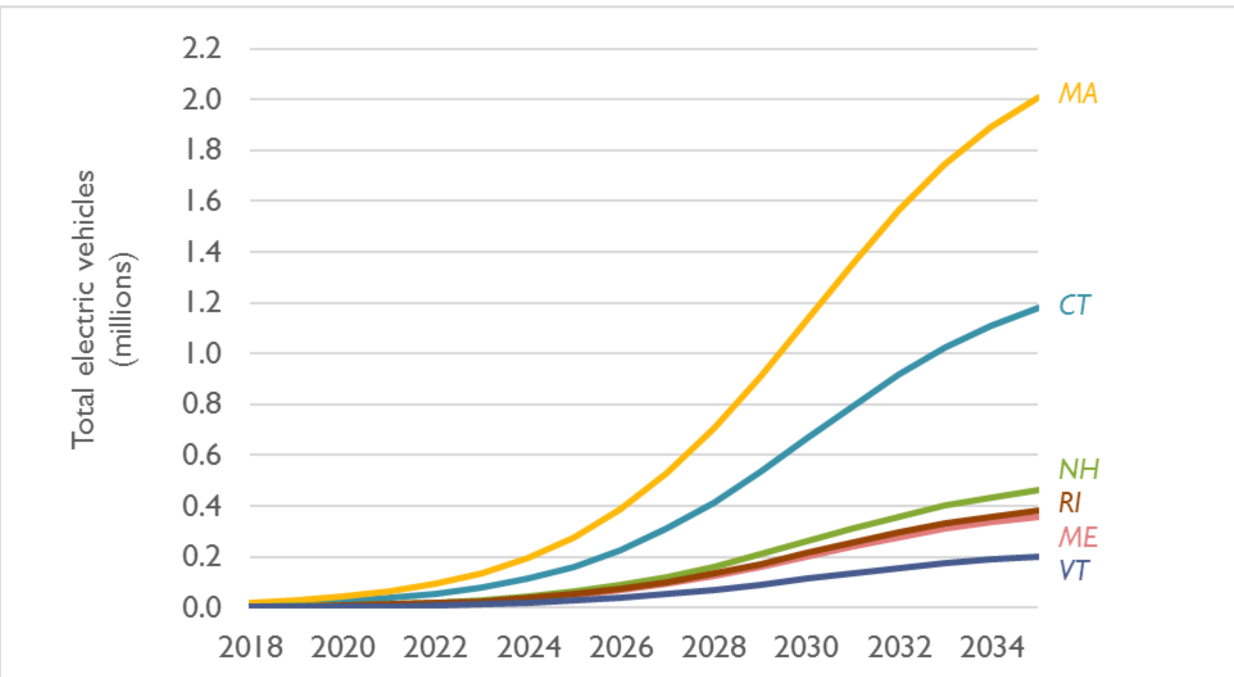


[237] Vehicles with gross vehicle weight ratings of greater than 8,501 pounds.

Electric vehicle assumptions

Our assumptions on electric vehicle deployment in the High Electricity Demand case correspond to the level of light-duty electric vehicles called for in the Eight-state Zero Emission Vehicle Memorandum of Understanding (commonly referred to as the "ZEV MOU").[238] Under the ZEV MOU, governors from eight states (California, Connecticut, Maryland, Massachusetts, New York, Oregon, Rhode Island, and Vermont), committed to a collective target of putting 3.3 million electric vehicles on the road by 2025 (i.e., about 10 percent of the light-duty vehicle stock). In this sensitivity, AESC 2018 assumes that the four New England states that are signatories to the ZEV MOU implement a share of this 3.3 million vehicle target in line with their current number of light-duty vehicles, respective to the number of registered automobiles in all eight states. AESC 2018 also assumes that electric vehicles are deployed in Maine and New Hampshire (the two New England states that have not signed the ZEV MOU) at levels that correspond to (a) the electric vehicles deployed in the other four states and (b) the number of registered automobiles in these two states. We assume that the number of electric vehicles deployed in each of the six states increases from 2018 to 2025 using a market adoption Bass Diffusion Model (i.e., an S-Curve) and continue increasing at the same trend through 2035 (see Figure 53).[239] By 2035, the number of electric vehicles corresponds to 87 percent of the number of registered automobiles in New England in 2016.

Figure 53. Projection of electric vehicles through 2035 by state



[238] The ZEV MOU can be found online at www.nescaum.org/documents/zev-mou-8-governors-signed-20131024.pdf/.

[239] Bass, Frank. 1969. "A New Product Growth for Model Consumer Durables." Management Science 15 (5).

For this sensitivity, we assume that current light-duty electric vehicles have an efficiency of 0.3 kWh per vehicle mile traveled (VMT).[240] Over time, AESC 2018 assumes that this efficiency increases, with a fleetwide light-duty vehicle average efficiency of 0.17 kWh per vehicle mile traveled in 2050.[241]

In addition, we assume that increased levels of electricity demand associated with new electric vehicles are spread across each month commensurate with monthly driving patterns (e.g., more demand in the summer during the high "driving season"), and that hourly electric vehicle charging patterns follow the trajectory described by San Diego Gas & Electric in its application to implement widespread transportation electrification.[242]

Note that this projection does not include any assumptions relating to electrification of non-light-duty vehicles. For the purposes of this analysis, we do not assume that electric vehicle batteries are used for storage—instead, we assume that the sole contribution of electric vehicles to the electric grid in this analysis is to increase the level of electricity demand.

Heat pump assumptions

Our assumptions on residential heat pump deployment follow the "plausibly optimistic" trajectory developed by Synapse on behalf of the Northeast Energy Efficiency Partnership (NEEP) in its July 2017 study titled "Northeastern Regional Assessment of Strategic Electrification."[243] This trajectory assumes that heat pumps replace conventional heating systems (e.g., from oil, propane, and natural gas) over time. Specifically, it assumes that residential heat pumps replace 30 percent of thermal heating load by 2035 (see Figure 54).[244] These assumptions will be the same in all six New England states.

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240 Current vehicle efficiency is based on the efficiency of typical 2016 models according to http://www.fueleconomy.gov/feg/PowerSearch.do?action=noform&path=1&year1=2015&year2=2017&vtype=Electric&pageno=2&sortBy=Comb&tabView=0&rowLimit=10.

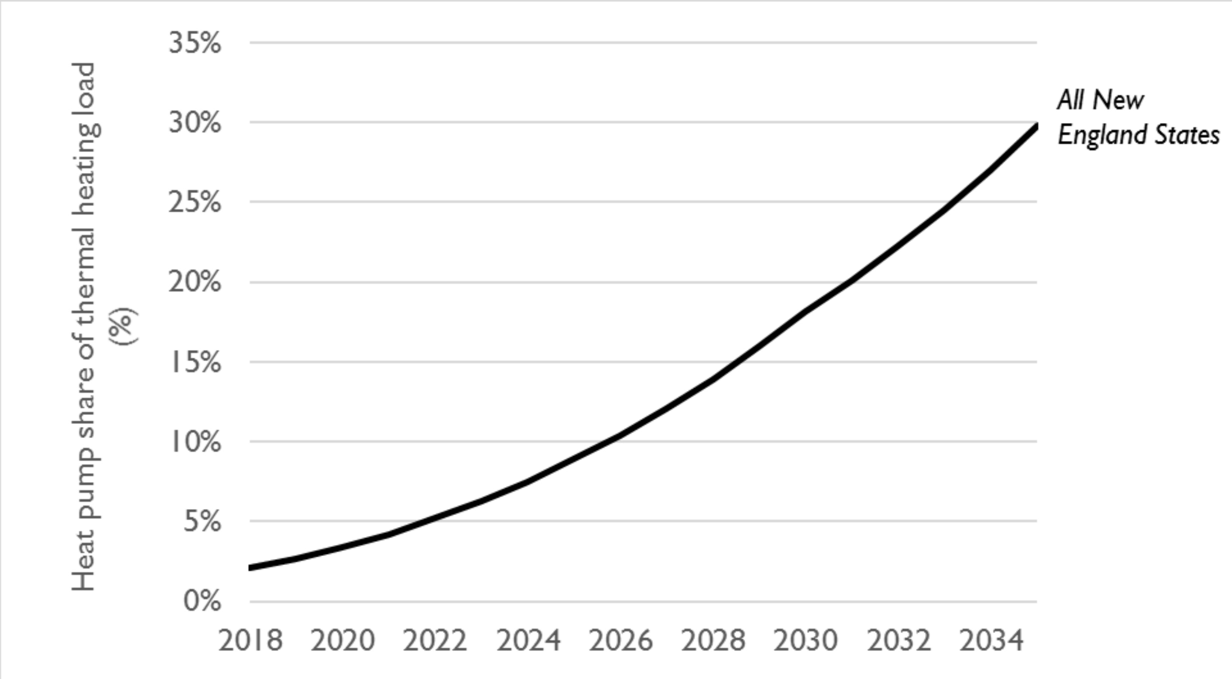
241 The long-term vehicle efficiency projection is based on projections developed by Idaho National Laboratory at http://avt.inel.gov/pdf/fsev/costs.pdf.

242 Detail on hourly electric vehicle charging can be found at https://www.sdge.com/regulatory-filing/20491/application-sdge-authority-implement-priority-review-and-standard-review. Note that this trajectory does not distinguish between fully battery-powered EVs (BEVs) and plug-in hybrid EVs (PEVs). Note also that this trajectory assumes implementation of time-of-use rates.

243 This report is available online at http://neep.org/sites/default/files/Strategic%20Electrification%20Regional%20Assessment.pdf.

244 Note that for simplification purposes, we assume that any increase in cooling load caused by new heat pump installations is cancelled out by heat pumps being a more efficient cooling technology.

Figure 54. Projection of residential heat pump sales through 2035 by state



We assume that the average coefficient of performance of residential heat pumps increases from 2.3 in 2018 to 2.9 in 2035. We assume that the electricity demand from residential heat pumps changes seasonally and hour-by-hour in line with thermal heating.[245]

With energy efficiency sensitivity

The main purpose of the With EE sensitivity is to estimate avoided costs that would be associated with demand response programs implemented outside of traditional energy efficiency funding mechanisms. For this sensitivity, we implemented the amount of incremental energy efficiency assumed by ISO New England in its 2017 CELT forecast.

Historically, ISO New England has based its near-term projections of incremental energy efficiency in its CELT forecast on the levels of energy efficiency cleared in the FCM. Longer-term estimates of energy efficiency have been forecasted by assuming sustained levels of energy efficiency budgets in future years, increasing costs of energy efficiency, and a discount rate adjustment—all of which typically result in declining levels of incremental energy efficiency relative to the near term. As a result, ISO New England has a tendency to underestimate the level of energy efficiency, and thus, overestimate the level of future electricity demand.

[245] Information on hourly residential heat pump demand can be found at http://en.openei.org/datasets/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states.

For the 2018 projection, ISO New England is planning to implement a number of substantial changes to its forecasting methodology.[246] These include using the cleared capacity in the third Annual Reconfiguration Auction (ARA) as a "launching point" for energy efficiency, rather than the more out-of-date value from the FCA. Had these changes been implemented in the 2017 CELT projection, ISO New England estimates that its summer peak projection of regional energy efficiency would have increased by 400 MW, or an increase of about 20 percent.[247] In addition, it is conceivable that the energy efficiency forecast could be changed in other ways to more accurately reflect the energy efficiency savings anticipated by New England program administrators.[248]

However, for the purposes of this sensitivity, AESC 2018 will use the 2017 CELT forecast in order to remain consistent with the same forecast year used in the main AESC 2018 scenario. We may want to revisit these assumptions in the 2019 update to the 2018 AESC study.

Figure 55 compares the electricity forecast in the main AESC 2018 Study (i.e., without incremental energy efficiency) to the electricity forecast in the With EE sensitivity. We have also included a "with energy efficiency" trajectory based on the soon-to-be adopted 2018 methodology.[249] On average, the 2018 methodology results in a decreased load of about 2 percent in any given year. In both "With EE" options, we assume that incremental energy efficiency continues to be added in each state at the same rate as assumed by ISO New England in 2026.

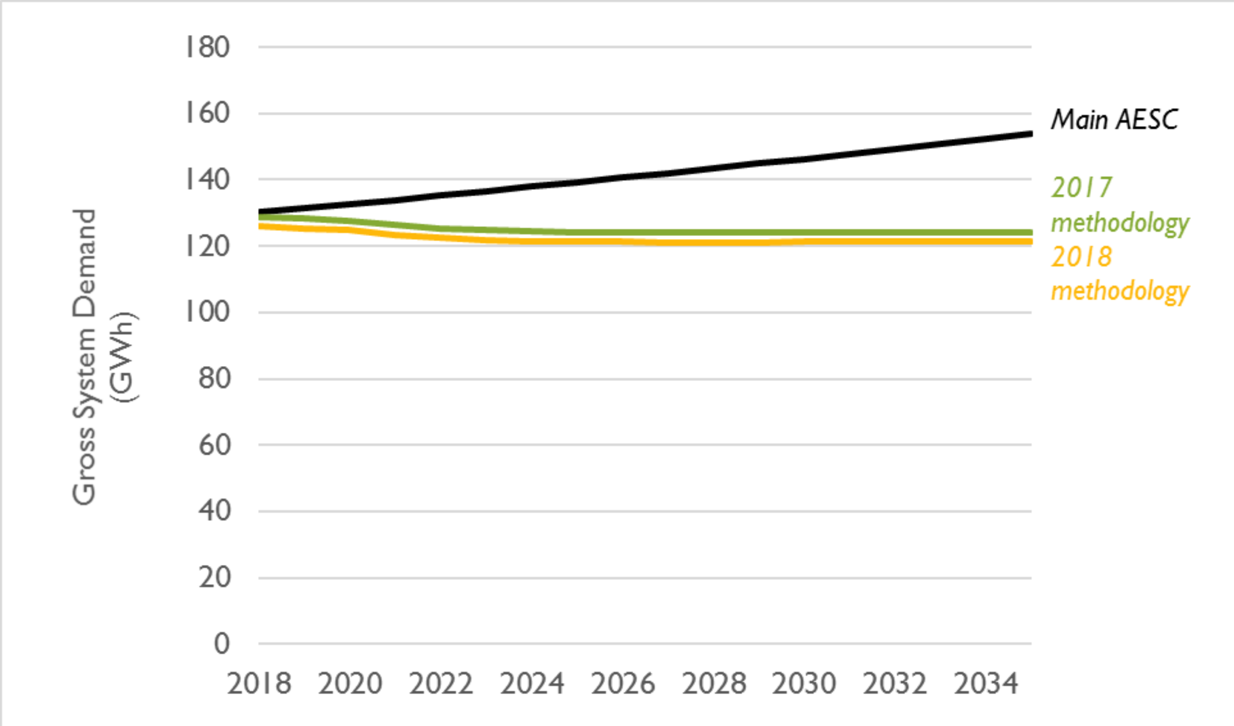
[246] See https://www.iso-ne.com/static-assets/documents/2017/10/eefwg_modeldesign_v3.pdf for a preliminary version of the ISO New England's 2018 energy efficiency forecast; the final forecast itself is due to be released in May 2018.

[247] For reference, ISO New England's forecast of econometric sales typically changes very little, with a decrease to the regional cumulative average growth rate of just 0.12 percent between the CELT 2015 and CELT 2017 studies.

[248] Additional information on potential ways for ISO New England to adjust its forecast can be found in http://www.synapse-energy.com/sites/default/files/Updated-Challenges-Electric-System-Planning-16-006.pdf.

[249] Note that this is a preliminary trajectory and will be updated when the final forecast itself is released in May 2018. At the time of this analysis, ISO New England's Energy Efficiency Working Group had only released summer peak energy efficiency projections (measured in MW). We convert these to MWh using the summer MW-to-annual MWh ratio present in the CELT 2017 projection.

Figure 55. Projection of regional, annual electricity demand in the main 2018 AESC Study compared to demand projections with energy efficiency



In this analysis, we did not make any assumptions regarding adjustments to annual load shapes. Instead, we simply decreased electricity demand in each hour by the percentage difference between annual electricity demand in the main 2018 AESC Study and the High Electricity Demand case. For example, if the two forecasts resulted in a difference in electricity demand in a certain region and year of 5 percent, then AESC 2018 decreased the electricity demand in each and every hour by 5 percent.[250]

[250] Note that this means we are effectively assuming the same shape for hourly demand as ISO New England, which is itself based on the hourly demand trends of 2002.

12.3. Results of Sensitivity Analysis

The following sections detail the results of the sensitivity analysis for energy prices, capacity prices, DRIPE, and RPS compliance.

Energy prices

Table 101 through Table 104 compare the wholesale energy price results for each of the four sensitivity runs against the main AESC run in terms of 15-year levelized costs for the Western and Central Massachusetts (WCMA) reporting region.[251]

Generally, we find that the levelized energy prices in the high and low gas price sensitivities correspond with the differences in Henry Hub prices described above.[252] As in the main 2018 AESC Study case, natural gas is the marginal resource in most hours and sets the price.

Similarly, because natural gas is the marginal resource in most hours, and because we do not alter the natural gas price in either the High Load sensitivity or With EE sensitivity, energy prices (on a levelized basis) closely resemble the prices in the main 2018 AESC Study case.

Table 101. 15-year levelized cost comparison for WCMA region (2018 $ / MWh)—High Gas Price sensitivity

	Annual All Hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018—Main	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2018—High Gas	$57.99	$64.46	$56.29	$50.81	$43.11
Percent Difference	19%	16%	9%	18%	17%

Notes: Levelization periods are 2018–2032 for AESC 2018. The real discount rate is 1.34 percent for AESC 2018. The same is true for all following tables.

Table 102. 15-year levelized cost comparison for WCMA region (2018 $ / MWh)—Low Gas Price sensitivity

	Annual All Hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018—Main	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2018—Low Gas	$45.13	$51.05	$44.59	$37.95	$32.03
Percent Difference	-7%	-8%	-13%	-12%	-13%

[251] WCMA is chosen as a representative region given that it is a proxy for the location of the ISO New England control area. This price effectively represents the hub price for ISO New England, reflecting congestion and losses. Note that all summarized energy prices are calculated using a load-weighted average.

[252] Note that a one percentage point increase in the Henry Hub price does not correspond to a one percentage point increase in the energy price. This is because other components which contribute to the energy price (e.g., plant heat rates, Algonquin Basis) are unchanged in the two natural gas price sensitivities.

Table 103. 15-year levelized cost comparison for WCMA region (2018 $ / MWh)—High Load sensitivity

	Annual All Hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018—Main	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2018—High Load	$49.40	$56.27	$53.04	$42.68	$37.06
Percent Difference	2%	1%	3%	-1%	1%

Table 104. 15-year levelized cost comparison for WCMA region (2018 $ / MWh)—With EE sensitivity

	Annual All Hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018—Main	$48.56	$55.67	$51.41	$42.91	$36.72
AESC 2018—With EE	$46.40	$53.27	$48.93	$40.98	$35.32
Percent Difference	-4%	-4%	-5%	-4%	-4%

Capacity prices

The avoided capacity cost will vary with the differing load levels in the sensitivity cases. In the With EE sensitivity, the avoided capacity costs (which are the actual clearing prices) in FCAs 9 to 12 are $0.26 to $0.39/kW-month lower than in the main AESC 2018 case (see Table 105). After FCA 12, the With EE avoided capacity costs rise slowly, sliding up the very shallow slope of final segment of the FCA 12 supply curve, reaching $4.95/kW-month (the FCA 13 price in the Reference case) in FCA 26.

In the High Load sensitivity, prices are very similar to the main AESC 2018 case through FCA 15, as demand rises up the very shallow slope of the final supply-curve segment. The higher loads result in the market price reaching the steep portion of the supply curve in FCA 16. Because of the higher loads and energy prices outside the summer peak (due to heat pumps and electric vehicles), new combined-cycle units will be able to bid lower in the High Load sensitivity than in the main AESC 2018 case, resulting in new generation clearing and capping the capacity price at a lower level than in the main AESC 2018 case. As in the main AESC 2018 case, the High Load sensitivity long-term equilibrium is an oscillation between a price similar to the cost of new entry and a lower price following major additions.

Table 105. AESC 2018 capacity prices (2018 $ / kW-month)

Commitment Period (June to May)	FCA	AESC 2018	High Load Sensitivity	With EE Sensitivity
2018/2019	9	$9.81	$9.55	$9.81
2019/2020	10	$7.28	$6.89	$7.28
2020/2021	11	$5.35	$5.09	$5.35
2021/2022	12	$4.74	$4.36	$4.79
2022/2023	13	$4.84	$4.36	$4.94
2023/2024	14	$4.94	$4.37	$5.03
2024/2025	15	$5.22	$4.56	$5.25
2025/2026	16	$5.65	$4.59	$6.22
2026/2027	17	$6.13	$4.63	$5.28
2027/2028	18	$6.60	$4.67	$6.22
2028/2029	19	$7.07	$4.71	$5.28
2029/2030	20	$7.54	$4.74	$6.22
2030/2031	21	$6.60	$4.78	$5.28
2031/2032	22	$7.07	$4.81	$6.22
2032/2033	23	$7.54	$4.85	$5.28
2033/2034	24	$6.60	$4.88	$6.22
2034/2035	25	$7.07	$4.92	$5.28
2035/2036	26	$7.54	$4.95	$6.22
15-year levelized		$6.42	$5.17	$5.92
Percent Difference		-	-19%	-8%

Notes: All prices are in 2018 $ per month. Levelization periods are 2015/2016 to 2029/2030 for AESC 2015 and 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 2.43 percent for AESC 2015 and 1.34 percent for AESC 2018.
Source: AESC 2015 Exhibit 5-32.

DRIPE

Energy DRIPE benefits will vary with the different load levels and market prices found in the three scenarios. All things being equal, higher market prices will tend to increase DRIPE benefits. Higher loads, however, will not change prices so long as the ratio of zonal-to-ISO loads remains constant. If zonal loads disproportionally increase, then this too will increase DRIPE benefits.

Table 106 summarizes the 10-year levelized DRIPE benefits by scenario, type, season, period, and zone.[253] Table 107 calculates the differences between the base case and the High Load and With EE scenarios. Zone-on-ROP differences, while not formally calculated, will be proportional to the zone-on-zone differences.

The High Load sensitivity has 10-year levelized loads, which are 2.4 percent higher, and prices that are 0.3 percent higher than the main 2018 AESC case. Both of these factors will tend to increase DRIPE benefits. The increase in loads, however, mostly occurs in later years when most DRIPE benefits have already been decayed. There are also modest differences in the load growth rate of different zones. As a

[253] As in Chapter 9, all DRIPE values have been levelized over 10 years reflecting the short time duration of DRIPE impacts. 15-year levelizations are provided in Appendix B.

result, summer zone-on-zone DRIPE values in the High Load case are almost identical to those in the base case and the winter values are less than 0.2 percent higher.

The case with added energy efficiency deviates more significantly from the base case. In the With EE case, levelized demand falls by 7.4 percent and prices by 3.7 percent. Lower prices and load levels reduce the value of DRIPE because price responsiveness is proportional to these two factors. As a result, the With EE DRIPE values decrease by about 5 percent in the summer and about 2.25 percent in the winter.

Table 106. 10-year levelized prices by scenario, season, period, and zone (2018$, 2018 installations)

Scen.	Type	Season	Period	ISO	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA	MA
Base Case	Zone-on-Zone	Summer	Peak	33.34	2.95	3.37	0.64	7.34	2.52	4.67	7.72	4.50	16.90
			Off-Pk	22.34	2.11	2.29	0.44	5.02	1.65	3.06	5.56	3.04	11.66
		Winter	Peak	44.26	4.34	4.66	0.94	9.33	3.28	6.07	9.98	6.03	22.08
			Off-Pk	31.59	3.32	3.42	0.68	6.65	2.28	4.23	6.93	4.33	15.49
	Zone-on-ROP	Summer	Peak		30.77	30.34	33.08	26.37	31.19	29.04	25.99	29.21	16.81
			Off-Pk		21.04	20.87	22.71	18.13	21.51	20.09	17.59	20.11	11.49
		Winter	Peak		40.29	39.97	43.69	35.30	41.35	38.56	34.65	38.60	22.55
			Off-Pk		28.52	28.42	31.16	25.19	29.56	27.61	24.91	27.50	16.35
High Load	Zone-on-Zone	Summer	Peak	32.03	2.83	3.23	0.61	7.06	2.42	4.49	7.43	4.33	16.24
			Off-Pk	21.63	2.04	2.21	0.42	4.87	1.60	2.96	5.39	2.94	11.30
		Winter	Peak	44.85	4.41	4.72	0.95	9.46	3.32	6.14	10.08	6.13	22.34
			Off-Pk	32.29	3.39	3.49	0.69	6.81	2.35	4.33	7.04	4.44	15.82
	Zone-on-ROP	Summer	Peak		29.57	29.16	31.79	25.33	29.98	27.91	24.97	28.07	16.16
			Off-Pk		20.40	20.23	22.02	17.57	20.84	19.48	17.05	19.50	11.14
		Winter	Peak		40.80	40.49	44.26	35.75	41.89	39.07	35.13	39.09	22.87
			Off-Pk		29.15	29.06	31.85	25.74	30.20	28.21	25.51	28.10	16.73
With EE	Zone-on-Zone	Summer	Peak	31.51	2.94	3.33	0.63	7.00	2.32	4.31	7.13	4.17	15.60
			Off-Pk	21.30	2.12	2.28	0.44	4.82	1.53	2.85	5.16	2.84	10.85
		Winter	Peak	43.29	4.46	4.76	0.96	9.19	3.11	5.79	9.56	5.78	21.13
			Off-Pk	30.86	3.40	3.48	0.69	6.54	2.16	4.03	6.62	4.15	14.81
	Zone-on-ROP	Summer	Peak		28.88	28.49	31.19	24.82	29.50	27.52	24.69	27.66	16.22
			Off-Pk		19.91	19.75	21.59	17.21	20.50	19.18	16.87	19.19	11.18
		Winter	Peak		39.15	38.85	42.64	34.42	40.50	37.82	34.05	37.83	22.48
			Off-Pk		27.69	27.60	30.39	24.54	28.92	27.05	24.46	26.93	16.27

Table 107. Change from main 2018 AESC case, zone-on-zone DRIPE benefits

Delta	Type	Season	Period	ISO	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA	MA
% Change from Base	High Load vs Base	Summer	Peak	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%	-4%
			Off-Peak	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%	-3%
		Winter	Peak	1%	2%	1%	1%	1%	1%	1%	1%	2%	1%
			Off-Peak	2%	2%	2%	2%	2%	3%	2%	2%	3%	2%
	EE vs Base	Summer	Peak	-5%	0%	-1%	-1%	-5%	-8%	-8%	-8%	-7%	-8%
			Off-Peak	-5%	0%	0%	0%	-4%	-7%	-7%	-7%	-7%	-7%
		Winter	Peak	-2%	3%	2%	2%	-2%	-5%	-5%	-4%	-4%	-4%
			Off-Peak	-2%	2%	2%	2%	-2%	-5%	-5%	-4%	-4%	-4%
$ Change from Base	High Load vs Base	Summer	Peak	-1.31	-0.12	-0.14	-0.02	-0.28	-0.10	-0.19	-0.29	-0.18	-0.66
			Off-Peak	-0.71	-0.07	-0.07	-0.01	-0.15	-0.05	-0.10	-0.17	-0.10	-0.36
		Winter	Peak	0.59	0.07	0.06	0.01	0.13	0.05	0.07	0.10	0.10	0.26
			Off-Peak	0.70	0.07	0.07	0.01	0.15	0.07	0.10	0.11	0.11	0.33
	EE vs Base	Summer	Peak	-1.83	0.00	-0.04	-0.01	-0.34	-0.20	-0.37	-0.59	-0.34	-1.30
			Off-Peak	-1.04	0.00	-0.01	0.00	-0.19	-0.12	-0.21	-0.39	-0.20	-0.81
		Winter	Peak	-0.97	0.12	0.10	0.02	-0.14	-0.17	-0.28	-0.42	-0.25	-0.95
			Off-Peak	-0.73	0.07	0.06	0.02	-0.11	-0.12	-0.20	-0.30	-0.18	-0.68

The High Load case has 10-year levelized loads which are 2.4 percent higher and prices that are 0.1 percent higher than the AESC 2018 base case. Both of these factors will tend to increase DRIPE benefits. The increase in loads, however, mostly occurs in later years when most DRIPE benefits have already been decayed. There are also modest differences in the load growth rates across the different zones and between the summer and winter seasons. As a result, summer zone-on-zone DRIPE values in the High Load case are 3-4 percent lower those in the base case and the winter values are less than 1-2 percent higher.

The case with added energy efficiency deviates more significantly from the base case. In the With EE case, levelized demand falls by 7.4 percent and prices by 3.7 percent. Lower prices and load levels reduce the value of DRIPE because price responsiveness is proportional to these two factors. As a result, the With EE DRIPE values decrease by about 5 percent in the summer and about 2 percent in the winter.

RPS

As directed by the Study Group, we developed RPS compliance costs for the High Load and With EE sensitivities only. Table 108 through Table 110 summarize the avoided cost of RPS compliance results for the High Load sensitivity, while Table 111 through Table 113 summarize the avoided cost of RPS compliance results for the With EE sensitivity.

Table 108. Summary of avoided cost of RPS compliance, new RPS categories, 2018–2032, 2018$/MWh

	CT-I	ME-I	MA-I	MA CES	MA APS	NH-I	NH-I Thermal	NH-II	RI-New	VT-II	VT-III
2018	$3.76	$2.13	$1.50	$0.64	$1.05	$1.86	$1.87	$0.12	$2.76	$0.34	$0.57
2019	$10.18	$0.21	$4.66	$2.08	$0.98	$5.06	$2.03	$0.33	$6.66	$1.15	$1.62
2020	$10.91	$0.21	$6.06	$3.08	$0.91	$6.00	$2.18	$0.38	$9.76	$1.73	$1.32
2021	$8.63	$0.20	$5.73	$2.43	$0.84	$4.95	$2.33	$0.37	$8.32	$1.83	$1.54
2022	$2.80	$0.20	$4.32	$0.00	$0.78	$1.56	$2.47	$0.30	$2.37	$1.48	$1.76
2023	$4.29	$0.00	$2.38	$0.00	$0.72	$2.46	$2.62	$0.15	$3.53	$0.86	$1.12
2024	$5.08	$0.00	$3.27	$0.00	$0.73	$2.99	$2.50	$0.17	$4.24	$1.10	$1.41
2025	$3.57	$0.00	$2.47	$0.00	$0.77	$2.15	$2.37	$0.12	$3.23	$0.86	$1.08
2026	$2.30	$0.00	$1.80	$0.00	$0.80	$1.34	$2.09	$0.08	$2.34	$0.62	$0.78
2027	$1.80	$0.00	$1.21	$0.00	$0.83	$0.60	$1.85	$0.05	$1.30	$0.42	$0.51
2028	$1.29	$0.00	$1.53	$0.00	$0.86	$0.77	$1.63	$0.05	$1.60	$0.50	$0.62
2029	$1.63	$0.00	$1.74	$0.04	$0.89	$0.91	$1.44	$0.06	$1.72	$0.59	$0.72
2030	$1.89	$0.00	$1.83	$0.12	$0.92	$0.95	$1.27	$0.06	$1.96	$0.65	$0.78
2031	$2.02	$0.00	$2.05	$0.22	$0.95	$1.02	$1.12	$0.06	$2.22	$0.74	$0.89
2032	$2.14	$0.00	$2.25	$0.33	$0.98	$1.08	$0.99	$0.07	$2.46	$0.83	$1.00
Levelized	**$4.28**	**$0.21**	**$2.91**	**$0.63**	**$0.86**	**$2.32**	**$1.94**	**$0.16**	**$3.72**	**$0.92**	**$1.06**

Table 109. Summary of avoided cost of RPS compliance, existing RPS categories, 2018–2032, 2018$/MWh

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	NH-III	NH-IV	RI-Existing	VT-I
2018	$0.56	$1.08	$0.65	$0.58	$0.23	$3.34	$0.33	$0.04	$1.08
2019	$0.45	$1.01	$0.64	$0.78	$0.22	$3.88	$0.41	$0.04	$1.05
2020	$0.35	$0.93	$0.62	$1.05	$0.22	$2.64	$0.41	$0.04	$1.09
2021	$0.24	$0.87	$0.61	$1.05	$0.21	$1.95	$0.41	$0.04	$1.06
2022	$0.24	$0.80	$0.60	$0.46	$0.21	$1.79	$0.19	$0.03	$1.03
2023	$0.23	$0.73	$0.15	$0.67	$0.21	$1.75	$0.28	$0.03	$0.64
2024	$0.23	$0.67	$0.14	$0.76	$0.20	$1.69	$0.32	$0.03	$0.62
2025	$0.23	$0.61	$0.14	$0.51	$0.20	$1.14	$0.21	$0.03	$0.61
2026	$0.22	$0.55	$0.14	$0.32	$0.19	$0.71	$0.13	$0.03	$0.63
2027	$0.22	$0.50	$0.14	$0.24	$0.19	$0.91	$0.10	$0.03	$0.61
2028	$0.21	$0.44	$0.13	$0.17	$0.19	$0.83	$0.07	$0.03	$0.59
2029	$0.21	$0.43	$0.13	$0.20	$0.18	$0.71	$0.08	$0.03	$0.61
2030	$0.20	$0.43	$0.13	$0.23	$0.18	$3.13	$0.09	$0.03	$0.60
2031	$0.20	$0.42	$0.13	$0.24	$0.18	$3.15	$0.10	$0.03	$0.58
2032	$0.20	$0.41	$0.12	$0.26	$0.17	$3.16	$0.11	$0.03	$0.60
Levelized	**$0.27**	**$0.67**	**$0.31**	**$0.51**	**$0.20**	**$2.07**	**$0.22**	**$0.03**	**$0.77**

Table 110. Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$4.28	$0.21	$2.91	$2.32	$3.72	$0.92
MA CES	NA	NA	$0.63	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.58	$4.39	$0.03	$1.83
Total	**$5.22**	**$0.52**	**$5.12**	**$6.71**	**$3.76**	**$2.76**

Note: Each state has multiple Classes or Tiers. Rhode Island and Maine have two, Connecticut and Vermont have three, and Massachusetts and New Hampshire have four. For simplicity, we sum avoided costs for all non-Class I/New RPS policies together in the "all other classes" row.

Table 111: Summary of avoided cost of RPS compliance, new RPS categories, 2018–2032, 2018$/MWh

	CT-I	ME-I	MA-I	MA CES	MA APS	NH-I	NH-I Thermal	NH-II	RI-New	VT-II	VT-III
2018	$2.77	$1.59	$1.12	$0.48	$1.05	$1.39	$1.87	$0.09	$2.20	$0.25	$0.43
2019	$7.59	$0.21	$3.48	$1.56	$0.98	$3.74	$2.03	$0.27	$4.86	$0.86	$1.30
2020	$6.94	$0.21	$3.41	$1.73	$0.91	$3.64	$2.18	$0.28	$4.86	$0.97	$1.32
2021	$5.57	$0.20	$2.83	$1.20	$0.84	$3.03	$2.33	$0.21	$4.11	$0.90	$1.24
2022	$3.45	$0.20	$1.81	$0.00	$0.78	$1.91	$2.47	$0.12	$2.77	$0.62	$0.82
2023	$2.12	$0.00	$1.11	$0.00	$0.72	$1.13	$2.62	$0.07	$1.82	$0.40	$0.52
2024	$1.50	$0.00	$0.85	$0.00	$0.73	$0.71	$2.50	$0.04	$1.34	$0.29	$0.37
2025	$1.38	$0.00	$0.81	$0.00	$0.77	$0.60	$2.37	$0.04	$1.13	$0.28	$0.36
2026	$1.16	$0.00	$0.74	$0.00	$0.80	$0.46	$2.09	$0.03	$0.94	$0.26	$0.32
2027	$0.94	$0.00	$0.67	$0.00	$0.83	$0.37	$1.85	$0.03	$0.80	$0.23	$0.28
2028	$0.80	$0.00	$0.58	$0.00	$0.86	$0.31	$1.63	$0.02	$0.69	$0.19	$0.24
2029	$0.75	$0.00	$0.49	$0.01	$0.89	$0.27	$1.44	$0.02	$0.60	$0.17	$0.20
2030	$0.71	$0.00	$0.43	$0.03	$0.92	$0.26	$1.27	$0.01	$0.53	$0.15	$0.18
2031	$0.63	$0.00	$0.43	$0.05	$0.95	$0.25	$1.12	$0.01	$0.51	$0.16	$0.19
2032	$0.54	$0.00	$0.44	$0.06	$0.98	$0.25	$0.99	$0.01	$0.52	$0.16	$0.20
Levelized	**$2.56**	**$0.17**	**$1.33**	**$0.36**	**$0.86**	**$1.28**	**$1.94**	**$0.09**	**$1.92**	**$0.40**	**$0.55**

Table 112: Summary of avoided cost of RPS compliance, existing RPS categories, 2018–2032, 2018$/MWh

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	NH-III	NH-IV	RI-Existing	VT-I
2018	$0.56	$1.08	$0.65	$0.43	$0.23	$2.87	$0.24	$0.04	$1.08
2019	$0.45	$1.01	$0.64	$0.78	$0.22	$3.11	$0.41	$0.04	$1.05
2020	$0.35	$0.93	$0.62	$1.05	$0.22	$2.71	$0.41	$0.04	$1.09
2021	$0.24	$0.87	$0.61	$0.96	$0.21	$2.06	$0.40	$0.04	$1.06
2022	$0.24	$0.80	$0.60	$0.57	$0.21	$1.43	$0.24	$0.03	$1.03
2023	$0.23	$0.73	$0.15	$0.33	$0.21	$1.08	$0.14	$0.03	$0.64
2024	$0.23	$0.67	$0.14	$0.23	$0.20	$1.01	$0.09	$0.03	$0.62
2025	$0.23	$0.61	$0.14	$0.20	$0.20	$0.96	$0.08	$0.03	$0.61
2026	$0.22	$0.55	$0.14	$0.16	$0.19	$0.90	$0.07	$0.03	$0.63
2027	$0.22	$0.50	$0.14	$0.13	$0.19	$0.84	$0.05	$0.03	$0.61
2028	$0.21	$0.44	$0.13	$0.10	$0.19	$0.80	$0.04	$0.03	$0.59
2029	$0.21	$0.43	$0.13	$0.09	$0.18	$0.79	$0.04	$0.03	$0.61
2030	$0.20	$0.43	$0.13	$0.09	$0.18	$0.78	$0.04	$0.03	$0.60
2031	$0.20	$0.42	$0.13	$0.08	$0.18	$0.76	$0.03	$0.03	$0.58
2032	$0.20	$0.41	$0.12	$0.07	$0.17	$0.74	$0.03	$0.03	$0.60
Levelized	**$0.27**	**$0.67**	**$0.31**	**$0.36**	**$0.20**	**$1.43**	**$0.16**	**$0.03**	**$0.77**

Table 113: Avoided cost of RPS compliance, aggregated by new and existing, by state, 2018$/MWh

	CT	ME	MA	NH	RI	VT
Class 1/New	$2.56	$0.17	$1.33	$1.28	$1.92	$0.40
MA CES	NA	NA	$0.36	NA	NA	NA
All Other Classes	$0.94	$0.31	$1.43	$3.62	$0.03	$1.32
Total	**$3.51**	**$0.48**	**$3.12**	**$4.89**	**$1.95**	**$1.72**

Note: Each state has multiple Classes or Tiers. Rhode Island and Maine have two, Connecticut and Vermont have three, and Massachusetts and New Hampshire have four. For simplicity, we sum avoided costs for all non-Class I/New RPS policies together in the "all other classes" row.

APPENDIX A. USAGE INSTRUCTIONS

This appendix describes instructions on how to compute levelization, how to convert between nominal and constant dollars, and how to compare results from this AESC study to previous versions. This appendix also includes a description of the role of energy efficiency programs in the capacity market.

Levelization Calculations

The 2018 AESC report presents levelized costs throughout on a 15-year basis; *Appendix B. Detailed Electric Outputs* presents levelized costs over different years. We calculate levelized costs for three different periods:

- 10-year: 2018 to 2027
- 15-year: 2018 to 2032
- 20-year: 2018 to 2037

All levelized costs are calculated using a real discount rate of 1.34 percent.

To calculate levelized costs beyond the three periods documented above, readers of the 2018 AESC study will require (a) a real discount rate (1.34 percent or otherwise specified), (b) the number of years and timeframe over which costs are to be levelized (e.g., 10 years—2018 through 2027 inclusive), and (c) the specific avoided cost values for the relevant reporting region. Equation 9 describes the formula used to estimate a levelized cost within Excel.

Equation 9. Excel formula used for calculating levelized costs

$$Levelized\ cost = -PMT(DiscountRate, NumberOfYears, NPV(DiscountRate, StreamOfCostsWithinPeriod))$$

Converting Constant 2018 Dollars to Nominal Dollars

Unless specifically noted, this report presents all dollar values in 2018 constant dollars. To convert constant 2018 dollars into nominal (current) dollars, please apply the formula described in Equation 10. Inflator and deflator conversion factors for AESC 2018 are presented in *Appendix E. Financial Parameters*.

Equation 10. Nominal-constant dollar conversion

$$Nominal\ Value = \frac{Constant\ Value\ (in\ 2018\ \$)}{Annual\ Conversion\ Factor\ to\ 2018\ \$}$$

Comparisons to Previous AESC Studies

A reader of the 2018 AESC Study may prepare comparisons of the 2018 AESC Study's 15-year levelized avoided costs with the 2015 AESC Study's avoided costs using the following steps:

- Identify the relevant reporting region and costing period
- Obtain the annual values of each avoided cost component from Appendix B in AESC 2018 and AESC 2015 (for the relevant reporting region and costing period)
- Convert the AESC 2015 values from 2015 dollars to 2018 dollars
- Calculate the 15-year levelized cost in 2018 dollars using the AESC 2018 real discount rate (1.34 percent)

Energy Efficiency Programs and the Capacity Market

A DSM program (such as energy efficiency) that produces a reduction in peak demand has the potential to avoid some amount of wholesale capacity cost associated with that reduction. The capacity cost that a specified reduction in peak demand will avoid in some given year will depend on the approach that the program administrator responsible for that energy efficiency program takes towards bidding all, or some, of that reduction into the relevant Forward Capacity Auction (FCA).

A program administrator can choose from a range of approaches. This range of approaches may include bidding between 100 percent and zero percent of the anticipated demand reduction from the program into the relevant FCAs. The following paragraphs describe the range of results that could occur in these two extremes:

- A program administrator that wishes to bid 100 percent of the anticipated demand reduction from its program into the relevant FCA must do so when that FCA is conducted, which can be up to three years in advance of the program implementation year.[254] Since a bid is a firm financial commitment, there is an associated financial risk if the program administrator is unable to actually deliver the full demand reduction for whatever reason. The value of this approach is the compensation paid by ISO New England, which is calculated by multiplying the quantity of peak reduction each year times the FCA price for the corresponding year.
- If a program administrator does not bid any of the anticipated demand reduction into any FCA, the program can still avoid some capacity costs if it has a measure life longer than three years. Under this approach, a program administrator responsible for an efficiency program starting January 2022

[254] For example, a program administrator responsible for an efficiency program that will be implemented starting January 2022 would have to bid 100 percent of the forecast demand reduction for June 2022 onwards from that program into FCA 13, which will be held in February 2019.

simply implements that program in that year, taking no action within the FCA. The customers' contribution to the ISO peak load, whenever that occurs in the summer of 2022, would be lower due to the program. As a result, this program administrator's customers would see some benefit from a lower capacity share starting in June 2023 (the following year). The reduced capacity requirement will reduce the capacity acquired in future FCAs, starting as early as the reconfiguration auctions for the power year starting in June 2023 and affecting all the auctions for the power years from June 2023 onward. AESC 2018 includes a phase-in for this effect. In addition to the program administrator, the entire region will benefit from the reduction of capacity purchases.

Wholesale Risk Premium

The retail price of electricity supply from a full-requirements fixed-price contract over a given period of time is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary service in effect during that supply period.

This premium over wholesale prices, or *wholesale risk premium,* is attributable to various costs that retail electricity suppliers incur in addition to the cost of acquiring wholesale energy, capacity, and ancillary service at wholesale market prices. These additional costs include costs incurred to mitigate cost risks associated with uncertainty in charges that will be borne by the supplier but whose unit prices cannot be definitely determined or hedged in advance. These cost risks include costs of hourly energy balancing, transitional capacity, ancillary services, and uplift.

The larger component of the risk is the difference between projected and actual energy requirements under the contract, driven by unpredictable variations in weather, economic activity, and/or customer migration. For example, during hot summers and cold winters, LSEs may need to procure additional energy at shortage prices, while in mild weather they may have excess supply under contract that they need to "dump" into the wholesale market at a loss. The same pattern holds in economic boom and bust cycles. In addition, the suppliers of power for utility standard-service offers run risks related to migration of customer load from utility service to competitive supply (presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss) and from competitive supply to the utility service (at times of high market prices, forcing the supplier to purchase additional power in a high-cost market).

AESC 2018 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[255] Estimates of the appropriate premium range from less than 5 percent to

[255] Capacity costs present a different risk profile than energy costs. With the advent of the Forward Capacity Market, suppliers have a good estimate of the capacity price three years in advance and of the capacity requirement for any given set of customers about one year in advance. (Reconfiguration auctions may affect the capacity charges, but the change in average costs is likely to be small.) On the other hand, since suppliers generally charge a dollars-per-MWh rate, and energy sales are subject to variation, the supplier retains some risk of under-recovery of capacity costs. There is no way to determine the extent to which an observed risk premium in bundled prices reflects adders on energy, capacity, ancillary services, RPS compliance, and other factors. Given the uncertainty and variability in the overall risk premium, we do not believe that

around 10 percent, based on analyses of confidential supplier bids—primarily in Massachusetts, Connecticut, and Maryland—to which the Analysis Team or sponsors have been privy.[256] Short-term procurements (for six months or a year into the future) may have smaller risk adders than longer-term procurements (upwards to about three years, which appears to be the limit of suppliers' willingness to offer fixed prices). Utilities that require suppliers to maintain higher credit levels will tend to see the resulting costs incorporated into the adders in supplier bids.

In the absence of robust information on the retail premium implicit in the prices being bid for retail supply in New England, we assume an 8 percent premium as a default risk premium.[257] The risk premium is a separate input to the avoided-cost spreadsheet. This allows program administrators will be able to input whatever level of risk premium they feel best reflects their specific experience, circumstances, economic and financial conditions, or regulatory direction.

The details of the risks and costs of serving load are somewhat different for Vermont and various municipal utilities, where vertically integrated utilities procure power from owned resources and a variety of long- and short-term contracts. For Vermont, we will include the 11.1 percent risk premium mandated by the Vermont Public Service Board. For the municipal utilities, program administrators should use a risk premium less than the 8 percent premium default.

Adjustment of Capacity Costs for Losses on ISO-Administered Pooled Transmission Facilities

There is a loss of electricity between the generating unit and ISO New England's delivery points, where power is delivered from the ISO New England-administered pooled transmission facilities (PTF) to the distribution utility local transmission and distribution systems. Therefore, a kilowatt load reduction at the ISO New England's delivery points, as a result of DSM on a given distribution network, reduces the quantity of electricity that a generator has to produce by one kilowatt plus the additional quantity that would have been required to compensate for losses.[258] The Encompass energy prices forecast model reflect these losses. However, the forecast of capacity costs from the FCM do not. Therefore, the forecast capacity costs should be adjusted for these losses.

ISO New England does not appear to publish estimates of the losses on the ISO-administered transmission system at system peak. ISO New England does release hourly values for System Load,

differentiating between energy and capacity premiums is warranted under this scope of work. We thus apply the retail premium uniformly to both energy and capacity values.

[256] Note that these bids are confidential and cannot be made public within AESC 2018.

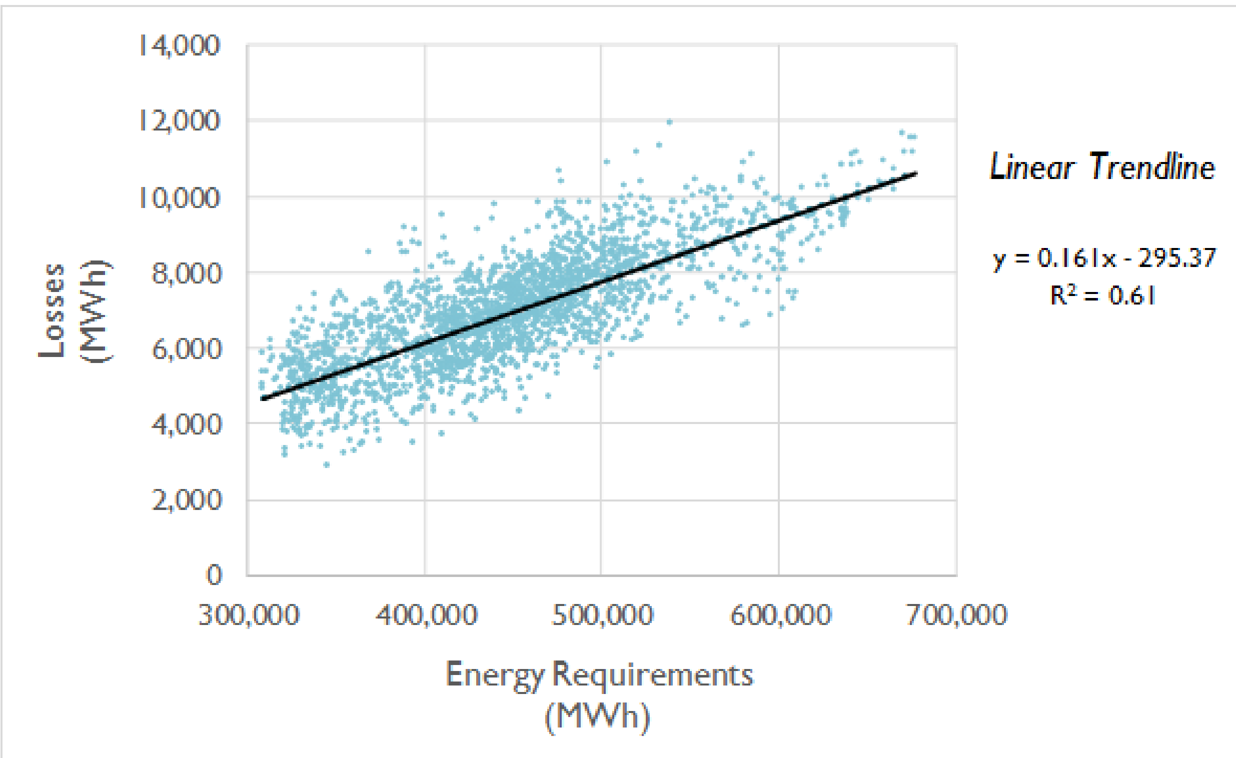
[257] In previous AESC studies, a default risk premium of 9 percent was assumed. This new value is based on our evaluation of default risk premiums and the comparison between standard offer/basic service prices to market prices.

[258] Computations of avoided costs sometimes assume that only average, and not marginal, losses are relevant at the peak hour. The reasoning for that approach is that changes in peak load will lead to changes in transmission and distribution investment, keeping average percentage losses approximately equal. The AESC 2018 avoided costs do not include any avoided PTF investments, so marginal losses are relevant in this situation.

which it defines as the sum of generation and net interchange, minus pumping load, and Non-PTF Demand. Non-PTF Demand is the term that the ISO uses for the load delivered into the networks of distribution utilities. Losses on the PTF system are thus the difference between the System Load and Non-PTF Demand. While PTF losses probably vary among zones, marginal losses by zone could not be identified using the available data.[259]

AESC 2018 analyzed the system losses against every hour for highest load of the month for 2010–2017. Figure 56 shows the results of the regression equation.

Figure 56. ISO New England hourly regression of energy requirements and losses (Jan 2010–May 2017)



Taking into account the 2010–2017 hourly regression results, AESC 2018 uses a marginal PTF demand loss factor for capacity costs of 1.6 percent.

[259] Since losses in any zone depend both on loads in that zone and flows into and out of that zone to the rest of the region, marginal losses as a function of load in each zone would be difficult to estimate from historical data.

APPENDIX B. DETAILED ELECTRIC OUTPUTS

This appendix provides instructions on how to apply the AESC 2018 base case avoided costs of electricity and avoided natural gas costs for the four costing periods (on-peak winter, off-peak winter, on-peak summer, off-peak summer). AESC 2018 provides detailed projections for each New England state as well as for specific regions within Connecticut and Massachusetts. These projections are provided as two-page tables in Appendix B. The Excel workbooks used to develop these tables are provided to program administrators. The instructions are also applicable to estimate avoided costs for the AESC 2018 sensitivity cases.

Appendix B provides tables for the reporting regions described in Table 114.

Table 114. Appendix B tables of avoided cost of electricity

State	Table
Connecticut *(costs provided in both 2018 $ and nominal $)*	Statewide SWCT (Southwest Connecticut including Norwalk, Stamford) OTCT (Rest of Connecticut, excluding Southwest Connecticut)
Massachusetts	Statewide SEMA (Southeast Massachusetts) WCMA (West-Central Massachusetts) NEMA (Northeast Massachusetts)
Maine	Statewide
New Hampshire	Statewide
Rhode Island	Statewide
Vermont	Statewide

Costing Periods

The tables for each reporting region present avoided costs by year for the following ISO New England defined costing periods:[260]

- Summer on-peak: The 16-hour block from 7 am till 11 pm, Monday–Friday (except ISO holidays), in the months of June–September (1,390 Hours, 15.9 percent of 8,760).261
- Summer off-peak: All other hours between 11 pm and 7 am, Monday–Friday, weekends, and ISO holidays in the months of June–September (1,530 Hours, 17.5 percent of 8,760).

[260] https://www.iso-ne.com/participate/support/glossary-acronyms/

[261] ISO New England holidays are New Year's Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

- Winter on-peak: The 16-hour block from 7 am till 11 pm, Monday–Friday (except ISO holidays), in the eight months of January–May and October–December (2,781 Hours, 31.7 percent of 8,760).

- Winter off-peak: All other hours between 11 pm and 7 am, Monday–Friday, all day on weekends, and ISO holidays–in the months of January–May and October–December (3,059 Hours, 34.9 percent of 8,760)

The "all-hours" avoided electricity cost for a given year, or set of years, is equal to the hour-weighted average of avoided costs for each costing period of that year one (see Equation 11).

Equation 11. Calculation of all-hours avoided electricity cost

$$\begin{aligned} &All\ hours\ avoided\ electricity\ cost \\ &\qquad = (15.9\% \times Summer\ OnPeak) + (17.5\% \times Summer\ OffPeak) \\ &\qquad + (31.7\% \times Winter\ OnPeak) + (34.9\% \times Winter\ OffPeak) \end{aligned}$$

Structure of Appendix B Tables

Each reporting region table contains the following avoided cost components:

1. Avoided unit cost of electric energy;
2. Avoided unit cost of electric capacity by demand reduction bidding strategy;
3. Energy DRIPE and capacity DRIPE for 2018 installations;
4. Energy DRIPE and capacity DRIPE for 2019 installations;
5. Avoided non-embedded costs;
6. Wholesale avoided costs of electricity (energy and capacity);
7. Cross-DRIPE 2018 and 2019 Installation;
8. Avoided REC costs to load;
9. 2018 Energy DRIPE values; and
10. 2019 Energy DRIPE values.

Values for each avoided cost component contains illustrative levelized values at the bottom of each cost column. A mapping is provided in Table 115.

Worksheet Components

The following section describes each avoided cost component.

Avoided cost of electricity results

Reading from left to right, the structure of page one of each table is as follows:

User-defined inputs

The tables have the following default values for the following three input assumptions:

1. Wholesale Risk Premium—8 percent[262]
2. Real Discount Rate—1.34 percent
3. Percent of Capacity Bid into the FCM—50 percent

Users may insert their own values for any or all of those three input assumptions.

Wholesale costs of electricity energy, $ per kWh (Columns a through d)

These columns provide the AESC 2018 annual wholesale electric energy prices outputted from the EnCompass simulation runs. Users should not normally need to use the input values directly or modify these values.

Wholesale REC costs to load $/kWh (Column e)

This column provides the AESC 2018 annual avoided REC costs specific to each state. Users should not normally need to use the input values directly or modify these values.

Retail cost of electric energy ($/kWh) (Columns f through i)

The AESC 2018 retail avoided energy costs are presented by year for each of the four energy costing periods: Winter On-Peak, Winter Off-Peak, Summer-On Peak, and Summer Off-Peak.[263]

AESC 2018 calculates the avoided energy cost for each year as described in Equation 12.

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[262] The wholesale risk premium for Vermont is 11.1 percent per Vermont DPS.

[263] The avoided energy costs are computed for the aggregate load shape in each zone by costing period, and they are applicable to DSM programs reducing load roughly in proportion to existing load. Other resources, such as load management and distributed generation, may have very different load shapes and significantly different avoided energy costs. Baseload resources, such as CHP systems, would tend to have lower avoided costs per kWh. Peaking resources, such as most non-CHP distributed generation and load management, would tend to have higher avoided costs per kWh.

Equation 12. Calculation of avoided energy cost

$$\begin{aligned} &\mathit{Avoided\ energy\ cost} \\ &\quad = (\mathit{modeled\ avoided\ wholesale\ energy\ cost}_{\ year} \\ &\quad + \mathit{avoided\ renewable\ energy\ certificate\ cost}_{\ year}) \times (1 \\ &\quad + \mathit{wholesale\ risk\ premium}) \end{aligned}$$

Forward Capacity Auction capacity price, $ per kW-year (Column j)

This column provides the AESC 2018 base case estimates for capacity prices reported on a calendar year basis. ISO New England generally reports capacity prices based on power-years (June 1 to May 31). Users should not normally need to use the input values directly or modify these values.

Uncleared Forward Capacity Auction capacity value, $ per kW-year (Column k)

This column provides the AESC 2018 base case estimates for capacity value based on uncleared capacity or unbid capacity avoided through energy efficiency measures. The values are multiplied by the AESC 2018 capacity price load effect and reserve margin percentages. Users should not normally need to use the input values directly or modify these values.

Avoided unit cost of electric capacity, $/kW-year (Columns l through n)

These columns enable a user to quantify the avoided capacity cost based on a simplified bidding strategy consisting of x percent of demand reductions from measures in each year bid (cleared) into the FCA for that year and the remaining 1-x percent not bid (uncleared) into any FCA. The default value for x is 50 percent. Users can insert their own input for that value in the user-defined inputs page of Appendix B.

The components of the avoided capacity cost are as follows:

- The retail avoided unit cost of capacity of a kW bid into the FCM in column l reflects an 8 percent adjustment to reflect losses from the customer meter to the ISO New England delivery point.
- The retail avoided unit cost of capacity in column m for avoided capacity not bid into an FCA reflects upward adjustments for the wholesale risk premium, the reserve margin in that year, a 1.6 percent adjustment to reflect PTF losses, and the load effect phase-in percentage. Because FCA auctions are set three years in advance of the actual delivery year, avoided capacity *not* bid into an FCA will not impact ISO New England's determination of forecasted peak until 2022 for measures installed in 2018.
- The Weighted Average *Capacity Value* based on percent bid in column YY is the *weighted average* avoided capacity of column e and f, reflecting an individual program administrator's percent of capacity that is bid into the FCM. The column presents a weighted average of 50 percent bid default value that may be changed by program administrators to reflect specific bidding strategies.

Under this approach the avoided capacity cost in each year is equal to the Weighted Average *Capacity Value* in column g for the relevant year multiplied by the demand reduction in that year.

Wholesale Non-embedded costs $/kWh (Columns o through r)

These columns provide the AESC 2018 annual estimates of non-embedded CO_2 values developed for AESC 2018 for each of the four energy costing periods.

Intrastate Demand-Reduction-Induced Price Effects (DRIPE) (Columns s through jj)

These columns provide separate projections of wholesale intrastate energy DRIPE and capacity DRIPE (wholesale and retail) for installation years 2018 and 2019. For programs installed after 2018, users should use the 2018 DRIPE values. The same approach applies for 2019.

Users should apply energy DRIPE values in accordance to relevant state regulations governing treatment of energy DRIPE. For example, Massachusetts only considers intrastate DRIPE benefits, whereas Rhode Island considers total DRIPE benefits.

The AESC 2018 uncleared capacity DRIPE values start in 2023 due to floor prices set through FCA 12.

The calculation steps to derive retail capacity DRIPE from wholesale capacity DRIPE follows the same logic and treatment as cleared and uncleared avoided capacity costs.

Wholesale cross DRIPE, $/kWh (Columns kk and ll)

These columns provide values for the annual values of wholesale electric cross-DRIPE avoided costs. Users should treat the avoided costs for electric cross-DRIPE similarly to energy DRIPE.

Rest of Pool Demand-Reduction-Induced Price Effects (DRIPE) (Columns mm through ddd)

These columns provide separate projections of wholesale rest-of-pool energy DRIPE and capacity DRIPE (wholesale and retail) for installation years 2018 and 2019. For programs installed after 2018, users should use the 2018 DRIPE values. The same approach applies for 2019.

As stated previously, users should apply energy DRIPE values in accordance to relevant state regulations governing treatment of energy DRIPE.

The calculation steps to derive rest-of-pool retail capacity DRIPE from wholesale capacity DRIPE follows the same logic and treatment as cleared and uncleared avoided capacity costs.

Wholesale Transmission and Distribution, $/kWh (Column eee)

These columns provide values the AESC 2018 avoided cost for Pool Transmission Facilities (PTF) of $94/kW-year in 2018 dollars. Utilities that use the avoided PTF costs should include only local transmission investments (those not eligible for PTF treatment) in their own avoided transmission analyses. Users should include distribution losses in applying this value.

Wholesale Reliability Values, $/kW-year (Columns fff through kkk)

These columns enable a user to quantify the wholesale reliability value based on a simplified bidding strategy consisting of x percent of demand reductions from measures in each year bid (cleared) into the FCA for that year and the remaining 1-x percent not bid (uncleared) into any FCA. The default value for x is 50 percent. Users can insert their own input for that value in the user-defined inputs page of Appendix B.

The components of the wholesale reliability value are as follows:

- The wholesale value of reliability for cleared capacity of a kW bid into the FCM in column. Users should reflect an 8 percent adjustment to reflect losses from the customer meter to the ISO New England delivery point.

- The wholesale value of reliability for uncleared capacity in column ggg. Users should include the wholesale risk premium, a 1.6 percent adjustment to reflect PTF losses, and distribution losses. The uncleared values already include an adjustment for reserve margins.

- The weighted average reliability v*alue* based on percent bid in column g is the *weighted average* avoided capacity of column e and f, reflecting an individual program administrator's percent of capacity that is bid into the FCM. The column presents a weighted average of 50 percent bid default value that may be changed by program administrators to reflect specific bidding strategies.

Under this approach the wholesale reliability value for 2018 installation in each year is equal to the Weighted Average *Value* in column hhh for the relevant year multiplied by the demand reduction in that year.

Guide to Applying the Avoided Costs

AESC 2018 allows users to specify certain inputs as well as to choose which of the avoided cost components to include in their analyses.

User-specified inputs

The avoided cost results are based upon default values for three inputs that users can specify. They are (1) the wholesale risk premium of 8 percent (11.1 percent for Vermont), (2) the real discount rate of 1.34 percent, and (3) a percentage of capacity bid into the FCM of 50 percent. The Excel workbook allows program administrators to specify their preferred values for those three inputs in the top left section of page one of each worksheet.

If a user wishes to specify a different value for any of the inputs, the user should enter the *new* value directly in the Appendix B Excel workbook. The calculations in the worksheet are linked to these values and new avoided costs will be calculated automatically.

Program administrators are responsible for developing and applying estimates of avoided transmission and distribution costs for their own specific system that would be separate inputs to the values in the provided tables.

Avoided costs of energy

Similar to prior AESC studies, AESC 2018 estimates avoided cost of energy based on the quantity energy reductions in a given year grossed up by an estimate of losses from the ISO delivery points to the end-use multiplied by the wholesale energy price. Each program administrator should obtain or calculate the losses applicable to its specific system as described in the section on avoided transmission and distribution costs.

The construct to estimate these avoided costs is as follows:

- Reduction in Winter On-Peak energy at the end-use
  × Winter On-Peak energy losses from the ISO delivery points to the end-use
  × the Winter On-Peak Energy value for that year by costing period
- Reduction in Winter Off-Peak energy at the end-use
  × Winter Off-Peak energy losses from the ISO delivery points to the end-use
  × the Winter Off-Peak Energy value for that year by costing period
- Reduction in Summer On-Peak energy at the end-use
  × Summer On-Peak energy losses from the ISO delivery points to the end-use
  × the Summer On-Peak Energy value for that year by costing period
- Reduction in Summer Off-Peak energy at the end-use
  × Summer Off-Peak energy losses from the ISO delivery points to the end-use
  × the Summer Off-Peak Energy value for that year by costing period.

DRIPE

The provided workbook tables include energy and capacity DRIPE values.

Capacity DRIPE

A user can estimate capacity DRIPE as follows:

kW reduction at the meter during system peak in a given year

× summer peak-hour losses from the ISO delivery points to the end-use
× weighted average capacity DRIPE for that year

Avoided cost of energy DRIPE

A program administrator can estimate the avoided cost of energy DRIPE as follows:

- Reduction in annual Winter On-Peak energy at the end-use
× Winter On-Peak energy losses from ISO delivery to the end-use
× the Winter On-Peak Energy DRIPE x (1 + wholesale risk premium)

- Reduction in annual Winter Off-Peak energy at the end-use
× Winter Off-Peak energy losses from ISO delivery to the end-use
× the Winter Off-Peak Energy DRIPE x (1 + wholesale risk premium)

- Reduction in annual Summer On-Peak energy at the end-use
× Summer On-Peak energy losses from ISO delivery to the end-use
× the Summer On-Peak Energy DRIPE x (1 + wholesale risk premium)

- Reduction in annual Summer Off-Peak energy at the end-use
× Summer Off-Peak energy losses from ISO delivery to the end-use
× the Summer Off-Peak Energy DRIPE x (1 + wholesale risk premium)

A program administrator who wishes to evaluate an efficiency measure implemented in 2018 would use the energy DRIPE values starting 2018. A program administrator who wishes to evaluate an efficiency measure implemented in 2019 would use the energy DRIPE values starting 2019.

Cross-fuel DRIPE

AESC 2018 provides estimates for electric-gas-electric DRIPE, which represents the benefits from a reduction in the quantity of electricity that reduces gas consumption and the subsequently reduces electric prices. The electric-gas-electric DRIPE value are as follows:

- Reduction in summer energy (peak + off-peak periods) at the end-use in the year × electric-gas-electric DRIPE for summer in that year x (1 + wholesale risk premium)

- Reduction in winter energy (peak + off-peak periods) at the end-use in the year × electric-gas-electric DRIPE for winter in that year x (1 + wholesale risk premium)

A program administrator who wishes to evaluate an efficiency measure implemented in 2018 would use the cross DRIPE values starting 2018. A program administrator who wishes to evaluate an efficiency measure implemented in 2019 would use the cross DRIPE values starting 2019. A program administrator who wishes to evaluate an efficiency measure implemented in 2018 would use the cross DRIPE values starting 2018. If desired, cross DRIPE values for a given season and time-period can be added to energy DRIPE values for the corresponding season and time period to simplify evaluations.

Avoided cost of non-embedded cost of carbon

The avoided cost of non-embedded carbon costs can be calculated as follows:

- Reduction in Winter On-Peak energy at the end-use
× Winter On-Peak energy losses from the ISO delivery points to the end-use

× the Non-embedded CO2 Costs Winter On-Peak Energy value for that year x (1 + wholesale risk premium)

- Reduction in Winter Off-Peak energy at the end-use
  × Winter Off-Peak energy losses from the ISO delivery points to the end-use
  × the Non-embedded CO2 Costs Winter Off-Peak Energy value for that year x (1 + wholesale risk premium)

- Reduction in Summer On-Peak energy at the end-use
  × Summer On-Peak energy losses from the ISO delivery points to the end-use
  × the Non-embedded CO2 Costs Summer On-Peak Energy value for that year x (1 + wholesale risk premium)

- Reduction in Summer Off-Peak energy at the end-use
  × Summer Off-Peak energy losses from the ISO delivery points to the end-use
  × the Non-embedded CO2 Costs Summer Off-Peak Energy value for that year x (1 + wholesale risk premium)

Local T&D capacity costs avoided by reductions in peak demand

Although not part of the provided tables, the benefits of peak demand reductions of avoided local transmission and distribution costs should be based upon specific program administrator information.

- Reduction in the peak demand used in estimating avoided transmission and distribution costs at the end-use × the utility-specific estimate of avoided T&D costs in $/kW-year.[264] AESC 2018 includes values for the avoided cost for pooled transmission facilities. Users including the avoided PTF values should only include avoided transmission costs for local facilities to avoid double counting.

Utility-Specific Costs Not Included in Worksheets to Be Added or Considered by Program Administrators

This section details additional inputs that are not specifically included in the worksheet and not part of the AESC 2018 scope of work, but that should be considered by program administrators.

Losses between the ISO delivery point and the end-use

The avoided energy and capacity costs and the estimates of DRIPE include energy and capacity losses on the ISO-administered PTFs, from the generator to the delivery points at which the PTF system connects to local non-PTF transmission or to distribution substations.

The presented values ***do not*** include the following losses:

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[264] Most demand-response and load-management programs will not avoid all transmission and distribution costs, since they are as likely to shift local loads to new hours as to reduce local peak load.

- Losses over the non-PTF transmission substations and lines to distribution substations
- Losses in distribution substations
- Losses from the distribution substations to the line transformers on primary feeders and laterals[265]
- Losses from the line transformers over the secondary lines and services to the customer meter[266]
- Losses from the customer meter to the end-use

Table 115. Appendix B mapping

Column	Description
a	Wholesale Costs of Electricity Energy Winter Peak ($/kWh)
b	Wholesale Costs of Electricity Energy Winter Off-peak ($/kWh)
c	Wholesale Costs of Electricity Energy Summer Peak ($/kWh)
d	Wholesale Costs of Electricity Energy Summer Off-peak ($/kWh)
e	Avoided REC Costs to Load ($/kWh)
f	Retail Cost of Electric Energy Winter Peak ($/kWh)
g	Retail Cost of Electric Energy Winter Off-peak ($/kWh)
h	Retail Cost of Electric Energy Summer Peak ($/kWh)
i	Retail Cost of Electric Energy Summer Off-peak ($/kWh)
j	Cleared Capacity Value ($/kW-yr)
k	Uncleared Capacity Value ($/kW-yr)
l	Avoided Unit Cost of Electric Capacity ($/kW-yr)
m	Avoided Unit Cost of Electric Capacity ($/kW-yr)
n	Avoided Unit Cost of Electric Capacity (weighted average) ($/kW-yr)
o	Non-embedded Costs Winter Peak ($/kWh)
p	Non-embedded Costs Winter Off-peak ($/kWh)
q	Non-embedded Costs Summer Peak ($/kWh)
r	Non-embedded Costs Summer Off-peak ($/kWh)
s	2018 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
t	2018 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
u	2018 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
v	2018 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
w	2018 Intrastate Demand-Reduction-Induced Price Effects ($/kW-yr)
x	2018 Intrastate Demand-Reduction-Induced Price Effects ($/kW-yr)
y	2018 Intrastate Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
z	2018 Intrastate Retail Demand-Reduction-Induced Price Effects ($/kW-yr)

[265] In some cases, this may involve multiple stages of transformers and distribution, as (for example) power is transformed from 115 kV transmission to 34 kV primary distribution and then to 14 kV primary distribution and then to 4 kV primary distribution, to which the line transformer is connected.

[266] Some customers receive their power from the utility at primary voltage. Since virtually all electricity is used at secondary voltages, these customers generally have line transformers on the customer side of the meter and secondary distribution within the customer facility.

Column	Description
aa	2018 Intrastate Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
bb	2019 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
cc	2019 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
dd	2019 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
ee	2019 Intrastate Demand-Reduction-Induced Price Effects ($/kWh)
ff	2019 Intrastate Demand-Reduction-Induced Price Effects ($/kW-yr)
gg	2019 Intrastate Demand-Reduction-Induced Price Effects ($/kW-yr)
hh	2019 Intrastate Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
ii	2019 Intrastate Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
jj	2019 Intrastate Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
kk	2018 Electric-gas-electric Cross DRIPE
ll	2019 Electric-gas-electric Cross DRIPE
mm	2018 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
nn	2018 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
oo	2018 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
pp	2018 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
qq	2018 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kW-yr)
rr	2018 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kW-yr)
ss	2018 Rest-of-pool Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
tt	2018 Rest-of-pool Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
uu	2018 Rest-of-pool Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
vv	2019 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
ww	2019 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
xx	2019 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
yy	2019 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kWh)
zz	2019 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kW-yr)
aaa	2019 Rest-of-pool Demand-Reduction-Induced Price Effects ($/kW-yr)
bbb	2019 Rest-of-pool Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
ccc	2019 Rest-of-pool Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
ddd	2019 Rest-of-pool Retail Demand-Reduction-Induced Price Effects ($/kW-yr)
eee	Wholesale Transmission and Distribution Cost ($/kW-yr)
fff	2018 Wholesale Reliability Value ($/kW-yr)
ggg	2018 Wholesale Reliability Value ($/kW-yr)
hhh	2018 Wholesale Reliability Value ($/kW-yr)
iii	2019 Wholesale Reliability Value ($/kW-yr)
jjj	2019 Wholesale Reliability Value ($/kW-yr)
kkk	2019 Wholesale Reliability Value ($/kW-yr)

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Maine

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0468	0.0424	0.0313	0.0254	0.0027	0.0534	0.0487	0.0367	0.0303	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0474	0.0440	0.0312	0.0277	0.0008	0.0522	0.0484	0.0346	0.0308	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0506	0.0477	0.0367	0.0321	0.0008	0.0556	0.0524	0.0406	0.0356	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0528	0.0495	0.0437	0.0370	0.0008	0.0579	0.0544	0.0481	0.0408	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0521	0.0476	0.0435	0.0353	0.0008	0.0572	0.0523	0.0478	0.0390	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0544	0.0479	0.0411	0.0323	0.0001	0.0589	0.0519	0.0446	0.0350	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0572	0.0537	0.0405	0.0368	0.0001	0.0619	0.0582	0.0439	0.0399	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0542	0.0512	0.0425	0.0380	0.0001	0.0587	0.0555	0.0460	0.0412	65.7	53.9	70.9	63.9	67.4	0.0421	0.0429	0.0410	0.0412
2026	0.0545	0.0512	0.0461	0.0403	0.0001	0.0590	0.0554	0.0499	0.0437	71.2	74.9	76.9	88.7	82.8	0.0417	0.0426	0.0406	0.0409
2027	0.0588	0.0551	0.0440	0.0383	0.0001	0.0636	0.0596	0.0477	0.0415	76.9	89.5	83.0	106.1	94.5	0.0414	0.0423	0.0403	0.0406
2028	0.0608	0.0533	0.0481	0.0393	0.0001	0.0658	0.0578	0.0520	0.0426	82.5	94.8	89.1	112.3	100.7	0.0411	0.0420	0.0401	0.0403
2029	0.0627	0.0573	0.0468	0.0396	0.0001	0.0678	0.0620	0.0507	0.0429	88.1	101.0	95.2	119.7	107.4	0.0408	0.0417	0.0398	0.0400
2030	0.0574	0.0541	0.0494	0.0452	0.0001	0.0621	0.0586	0.0535	0.0490	83.9	97.7	90.6	115.8	103.2	0.0403	0.0412	0.0393	0.0395
2031	0.0560	0.0522	0.0447	0.0391	0.0001	0.0607	0.0565	0.0484	0.0423	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0544	0.0507	0.0457	0.0399	0.0001	0.0589	0.0549	0.0495	0.0433	88.1	101.0	95.2	119.7	107.4	0.0394	0.0402	0.0384	0.0386
2033	0.0562	0.0490	0.0455	0.0369	0.0001	0.0609	0.0531	0.0493	0.0400	83.9	97.7	90.6	115.8	103.2	0.0390	0.0398	0.0380	0.0382
2034	0.0548	0.0459	0.0484	0.0375	0.0001	0.0594	0.0497	0.0524	0.0406	82.5	94.8	89.1	112.3	100.7	0.0386	0.0394	0.0376	0.0378
2035	0.0567	0.0503	0.0523	0.0447	0.0001	0.0614	0.0545	0.0566	0.0484	88.1	101.0	95.2	119.7	107.4	0.0382	0.0390	0.0372	0.0374
2036	0.0569	0.0499	0.0544	0.0463	0.0001	0.0616	0.0540	0.0589	0.0501	89.6	102.6	96.8	121.6	109.2	0.0378	0.0386	0.0368	0.0370
2037	0.0571	0.0494	0.0566	0.0479	0.0001	0.0617	0.0535	0.0613	0.0518	91.1	104.3	98.4	123.6	111.0	0.0374	0.0381	0.0364	0.0366
2038	0.0572	0.0490	0.0589	0.0495	0.0001	0.0619	0.0530	0.0638	0.0536	92.6	105.9	100.0	125.5	112.8	0.0369	0.0377	0.0360	0.0362
2039	0.0574	0.0485	0.0613	0.0512	0.0001	0.0621	0.0525	0.0663	0.0555	94.2	107.6	101.7	127.5	114.6	0.0366	0.0373	0.0356	0.0358
2040	0.0576	0.0481	0.0638	0.0530	0.0001	0.0623	0.0520	0.0690	0.0574	95.7	109.3	103.4	129.6	116.5	0.0362	0.0369	0.0352	0.0354
2041	0.0577	0.0476	0.0664	0.0548	0.0001	0.0625	0.0516	0.0718	0.0593	97.3	111.1	105.1	131.7	118.4	0.0358	0.0365	0.0348	0.0351
2042	0.0579	0.0472	0.0690	0.0567	0.0001	0.0627	0.0511	0.0747	0.0614	98.9	112.9	106.9	133.8	120.3	0.0354	0.0361	0.0345	0.0347
2043	0.0581	0.0468	0.0718	0.0587	0.0001	0.0628	0.0506	0.0777	0.0635	100.6	114.7	108.6	135.9	122.3	0.0350	0.0357	0.0341	0.0343
2044	0.0583	0.0463	0.0747	0.0607	0.0001	0.0630	0.0502	0.0808	0.0657	102.3	116.5	110.5	138.1	124.3	0.0346	0.0354	0.0337	0.0339
2045	0.0584	0.0459	0.0777	0.0628	0.0001	0.0632	0.0497	0.0841	0.0680	104.0	118.4	112.3	140.3	126.3	0.0342	0.0350	0.0334	0.0336
2046	0.0586	0.0455	0.0809	0.0650	0.0001	0.0634	0.0492	0.0874	0.0703	105.7	120.3	114.2	142.5	128.3	0.0339	0.0346	0.0330	0.0332
2047	0.0588	0.0451	0.0841	0.0672	0.0001	0.0636	0.0488	0.0910	0.0727	107.5	122.2	116.1	144.8	130.4	0.0335	0.0342	0.0326	0.0329
2048	0.0590	0.0447	0.0875	0.0696	0.0001	0.0638	0.0484	0.0946	0.0752	109.3	124.2	118.0	147.1	132.6	0.0332	0.0339	0.0323	0.0325
2049	0.0591	0.0443	0.0911	0.0720	0.0001	0.0640	0.0479	0.0984	0.0778	111.1	126.1	120.0	149.5	134.7	0.0328	0.0335	0.0319	0.0322
2050	0.0593	0.0439	0.0947	0.0744	0.0001	0.0641	0.0475	0.1024	0.0805	112.9	128.2	122.0	151.9	136.9	0.0324	0.0331	0.0316	0.0318
Levelized Costs																		
10 years (2018-2027)	0.0527	0.0489	0.0399	0.0342	0.0007	0.0577	0.0536	0.0438	0.0376	73.3	26.4	79.2	31.2	55.2	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0545	0.0504	0.0421	0.0362	0.0005	0.0594	0.0549	0.0460	0.0396	76.9	48.6	83.1	57.6	70.4	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0558	0.0492	0.0518	0.0435	0.0003	0.0606	0.0535	0.0563	0.0473	85.1	75.7	92.0	89.7	90.8	0.0396	0.0404	0.0385	0.0388

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Maine

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0036	0.0028	0.0022	0.0015	39.2	-	42.4	-	21.2	-	-	-	-	-	-	-	-	-	0.0015	0.0000
2019	0.0057	0.0042	0.0034	0.0025	20.6	-	22.2	-	11.1	0.0036	0.0027	0.0022	0.0016	24.8	-	26.7	-	13.4	0.0023	0.0014
2020	0.0065	0.0050	0.0043	0.0031	24.9	-	26.9	-	13.4	0.0060	0.0046	0.0039	0.0029	30.8	-	33.3	-	16.6	0.0025	0.0023
2021	0.0068	0.0053	0.0051	0.0037	4.1	-	4.5	-	2.2	0.0067	0.0052	0.0050	0.0036	5.5	-	6.0	-	3.0	0.0026	0.0023
2022	0.0060	0.0046	0.0046	0.0031	2.8	-	3.0	-	1.5	0.0067	0.0051	0.0050	0.0035	4.2	-	4.5	-	2.3	0.0023	0.0023
2023	0.0050	0.0037	0.0035	0.0023	-	2.7	-	3.2	1.6	0.0063	0.0047	0.0043	0.0029	2.8	-	3.0	-	1.5	0.0017	0.0017
2024	0.0041	0.0032	0.0026	0.0020	-	4.6	-	5.5	2.8	0.0053	0.0041	0.0034	0.0025	-	2.7	-	3.2	1.6	0.0011	0.0011
2025	0.0028	0.0022	0.0020	0.0015	-	76.2	-	90.3	45.1	0.0038	0.0030	0.0027	0.0020	-	59.7	-	70.8	35.4	0.0008	0.0008
2026	0.0015	0.0011	0.0011	0.0008	-	89.9	-	106.6	53.3	0.0028	0.0021	0.0021	0.0015	-	81.3	-	96.4	48.2	0.0006	0.0006
2027	0.0009	0.0007	0.0006	0.0005	-	88.1	-	104.4	52.2	0.0015	0.0012	0.0010	0.0008	-	94.7	-	112.2	56.1	0.0003	0.0003
2028	-	-	-	-	-	67.5	-	79.9	40.0	0.0009	0.0007	0.0006	0.0005	-	93.0	-	110.2	55.1	0.0001	0.0001
2029	-	-	-	-	-	44.4	-	52.6	26.3	-	-	-	-	-	71.7	-	85.0	42.5	0.0001	0.0001
2030	-	-	-	-	-	21.6	-	25.6	12.8	-	-	-	-	-	39.5	-	46.8	23.4	0.0001	0.0001
2031	-	-	-	-	-	10.1	-	12.0	6.0	-	-	-	-	-	22.8	-	27.0	13.5	0.0001	0.0001
2032	-	-	-	-	-	2.9	-	3.5	1.7	-	-	-	-	-	10.7	-	12.7	6.4	0.0001	0.0001
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2.6	-	3.1	1.5	0.0001	0.0001
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
Levelized Costs																				
10 years (2018-2027)	0.0044	0.0033	0.0030	0.0021	9.6	26.3	10.4	31.2	20.0	0.0043	0.0033	0.0030	0.0021	7.0	24.3	7.6	28.8	17.3	0.0016	0.0013
15 years (2018-2032)	0.0030	0.0023	0.0020	0.0015	6.6	27.9	7.1	33.0	19.2	0.0030	0.0023	0.0021	0.0015	4.9	32.7	5.2	38.8	20.8	0.0011	0.0009
30 years (2018-2047)	0.0016	0.0013	0.0011	0.0008	3.6	15.3	3.9	18.2	10.6	0.0017	0.0013	0.0012	0.0008	2.7	18.1	2.9	21.4	11.5	0.0007	0.0006

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Maine

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0351	0.0246	0.0241	0.0157	447.7	-	483.5	-	241.8	-	-	-	-	-	-	-	-	-
2019	0.0547	0.0383	0.0367	0.0266	234.5	-	253.2	-	126.6	0.0353	0.0247	0.0237	0.0171	282.5	-	305.1	-	152.5
2020	0.0626	0.0452	0.0466	0.0323	285.5	-	308.3	-	154.1	0.0580	0.0419	0.0431	0.0299	353.6	-	381.9	-	191.0
2021	0.0656	0.0472	0.0565	0.0379	47.6	-	51.4	-	25.7	0.0646	0.0464	0.0556	0.0373	63.7	-	68.8	-	34.4
2022	0.0587	0.0407	0.0501	0.0320	31.8	-	34.3	-	17.2	0.0647	0.0449	0.0552	0.0352	48.2	-	52.0	-	26.0
2023	0.0436	0.0293	0.0339	0.0213	-	30.5	-	36.1	18.1	0.0548	0.0369	0.0427	0.0268	32.0	-	34.6	-	17.3
2024	0.0352	0.0256	0.0251	0.0186	-	53.2	-	63.1	31.5	0.0454	0.0331	0.0323	0.0240	-	30.9	-	36.6	18.3
2025	0.0234	0.0171	0.0187	0.0136	-	874.1	-	1035.8	517.9	0.0322	0.0236	0.0258	0.0187	-	685.5	-	812.4	406.2
2026	0.0122	0.0088	0.0106	0.0074	-	1032.2	-	1223.2	611.6	0.0227	0.0162	0.0197	0.0137	-	933.5	-	1106.3	553.1
2027	0.0075	0.0055	0.0058	0.0040	-	1010.8	-	1197.9	598.9	0.0127	0.0092	0.0097	0.0068	-	1086.9	-	1288.0	644.0
2028	0.0000	0.0000	0.0000	0.0000	-	774.3	-	917.6	458.8	0.0075	0.0051	0.0061	0.0040	-	1067.7	-	1265.2	632.6
2029	0.0000	0.0000	0.0000	0.0000	-	509.2	-	603.4	301.7	-	-	-	-	-	823.0	-	975.3	487.6
2030	-	-	-	-	-	247.9	-	293.7	146.9	-	-	-	-	-	453.5	-	537.5	268.7
2031	-	-	-	-	-	115.8	-	137.2	68.6	-	-	-	-	-	261.8	-	310.3	155.1
2032	-	-	-	-	-	33.6	-	39.8	19.9	-	-	-	-	-	123.1	-	145.9	72.9
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.9	-	35.4	17.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0404	0.0286	0.0312	0.0212	109.6	302.0	118.4	357.8	228.8	0.0391	0.0277	0.0308	0.0210	80.6	278.6	87.1	330.1	197.9
15 years (2018-2032)	0.0278	0.0197	0.0215	0.0146	75.5	320.0	81.5	379.2	220.5	0.0274	0.0194	0.0216	0.0147	55.5	375.7	60.0	445.2	238.2
30 years (2018-2047)	0.0153	0.0108	0.0118	0.0080	41.5	176.0	44.8	208.5	121.2	0.0151	0.0107	0.0119	0.0081	30.5	207.6	33.0	246.0	131.6

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **Maine**

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **New Hampshire**

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0472	0.0430	0.0318	0.0258	0.0074	0.0590	0.0545	0.0423	0.0358	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0481	0.0447	0.0317	0.0284	0.0113	0.0641	0.0604	0.0465	0.0428	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0515	0.0484	0.0375	0.0326	0.0087	0.0650	0.0616	0.0499	0.0446	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0537	0.0502	0.0455	0.0378	0.0067	0.0653	0.0615	0.0564	0.0481	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0533	0.0484	0.0445	0.0359	0.0051	0.0631	0.0578	0.0536	0.0443	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0548	0.0485	0.0417	0.0327	0.0055	0.0651	0.0583	0.0510	0.0413	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0580	0.0545	0.0409	0.0372	0.0050	0.0681	0.0642	0.0495	0.0456	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0549	0.0519	0.0431	0.0386	0.0041	0.0637	0.0606	0.0510	0.0461	65.7	53.9	70.9	63.9	67.4	0.0421	0.0429	0.0410	0.0412
2026	0.0552	0.0517	0.0468	0.0409	0.0034	0.0633	0.0596	0.0542	0.0479	71.2	74.9	76.9	88.7	82.8	0.0417	0.0426	0.0406	0.0409
2027	0.0596	0.0558	0.0448	0.0388	0.0027	0.0672	0.0632	0.0513	0.0448	76.9	89.5	83.0	106.1	94.5	0.0414	0.0423	0.0403	0.0406
2028	0.0615	0.0541	0.0489	0.0399	0.0024	0.0690	0.0611	0.0554	0.0457	82.5	94.8	89.1	112.3	100.7	0.0411	0.0420	0.0401	0.0403
2029	0.0633	0.0580	0.0480	0.0406	0.0023	0.0709	0.0651	0.0543	0.0463	88.1	101.0	95.2	119.7	107.4	0.0408	0.0417	0.0398	0.0400
2030	0.0582	0.0549	0.0506	0.0462	0.0023	0.0653	0.0618	0.0571	0.0524	83.9	97.7	90.6	115.8	103.2	0.0403	0.0412	0.0393	0.0395
2031	0.0577	0.0542	0.0459	0.0400	0.0023	0.0649	0.0610	0.0521	0.0457	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0564	0.0526	0.0468	0.0405	0.0028	0.0639	0.0598	0.0535	0.0468	88.1	101.0	95.2	119.7	107.4	0.0394	0.0402	0.0384	0.0386
2033	0.0610	0.0536	0.0475	0.0388	0.0029	0.0690	0.0610	0.0544	0.0451	83.9	97.7	90.6	115.8	103.2	0.0390	0.0398	0.0380	0.0382
2034	0.0602	0.0505	0.0504	0.0397	0.0030	0.0683	0.0578	0.0577	0.0461	82.5	94.8	89.1	112.3	100.7	0.0386	0.0394	0.0376	0.0378
2035	0.0622	0.0555	0.0562	0.0476	0.0031	0.0706	0.0633	0.0641	0.0548	88.1	101.0	95.2	119.7	107.4	0.0382	0.0390	0.0372	0.0374
2036	0.0634	0.0559	0.0591	0.0497	0.0034	0.0721	0.0640	0.0675	0.0573	89.6	102.6	96.8	121.6	109.2	0.0378	0.0386	0.0368	0.0370
2037	0.0646	0.0562	0.0622	0.0519	0.0036	0.0737	0.0646	0.0711	0.0600	91.1	104.3	98.4	123.6	111.0	0.0374	0.0381	0.0364	0.0366
2038	0.0658	0.0566	0.0654	0.0542	0.0039	0.0753	0.0653	0.0748	0.0628	92.6	105.9	100.0	125.5	112.8	0.0369	0.0377	0.0360	0.0362
2039	0.0671	0.0569	0.0688	0.0566	0.0042	0.0770	0.0660	0.0788	0.0657	94.2	107.6	101.7	127.5	114.6	0.0366	0.0373	0.0356	0.0358
2040	0.0684	0.0573	0.0724	0.0592	0.0045	0.0787	0.0667	0.0830	0.0687	95.7	109.3	103.4	129.6	116.5	0.0362	0.0369	0.0352	0.0354
2041	0.0697	0.0577	0.0761	0.0618	0.0048	0.0804	0.0675	0.0874	0.0719	97.3	111.1	105.1	131.7	118.4	0.0358	0.0365	0.0348	0.0351
2042	0.0710	0.0580	0.0801	0.0645	0.0052	0.0822	0.0682	0.0921	0.0753	98.9	112.9	106.9	133.8	120.3	0.0354	0.0361	0.0345	0.0347
2043	0.0723	0.0584	0.0843	0.0674	0.0056	0.0841	0.0691	0.0970	0.0788	100.6	114.7	108.6	135.9	122.3	0.0350	0.0357	0.0341	0.0343
2044	0.0737	0.0587	0.0886	0.0704	0.0060	0.0861	0.0699	0.1022	0.0825	102.3	116.5	110.5	138.1	124.3	0.0346	0.0354	0.0337	0.0339
2045	0.0751	0.0591	0.0932	0.0735	0.0064	0.0880	0.0708	0.1076	0.0863	104.0	118.4	112.3	140.3	126.3	0.0342	0.0350	0.0334	0.0336
2046	0.0765	0.0595	0.0981	0.0768	0.0069	0.0901	0.0717	0.1134	0.0904	105.7	120.3	114.2	142.5	128.3	0.0339	0.0346	0.0330	0.0332
2047	0.0780	0.0599	0.1032	0.0802	0.0074	0.0922	0.0727	0.1194	0.0946	107.5	122.2	116.1	144.8	130.4	0.0335	0.0342	0.0326	0.0329
2048	0.0795	0.0602	0.1085	0.0837	0.0080	0.0944	0.0737	0.1258	0.0991	109.3	124.2	118.0	147.1	132.6	0.0332	0.0339	0.0323	0.0325
2049	0.0810	0.0606	0.1142	0.0875	0.0086	0.0967	0.0747	0.1325	0.1037	111.1	126.1	120.0	149.5	134.7	0.0328	0.0335	0.0319	0.0322
2050	0.0825	0.0610	0.1201	0.0913	0.0092	0.0991	0.0758	0.1396	0.1086	112.9	128.2	122.0	151.9	136.9	0.0324	0.0331	0.0316	0.0318

Levelized Costs																		
10 years (2018-2027)	0.0535	0.0496	0.0407	0.0347	0.0061	0.0644	0.0601	0.0505	0.0441	73.3	26.4	79.2	31.2	55.2	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0554	0.0512	0.0430	0.0368	0.0049	0.0651	0.0606	0.0517	0.0451	76.9	48.6	83.1	57.6	70.4	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0612	0.0537	0.0564	0.0467	0.0048	0.0713	0.0632	0.0661	0.0556	85.1	75.7	92.0	89.7	90.8	0.0396	0.0404	0.0385	0.0388

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2. Uncleared capacity value includes reserve margin and uncleared load forecast effect
3. Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4. Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5. Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6. Assumes bid percentage of 50.0%
7. Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8. Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: New Hampshire

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0039	0.0029	0.0025	0.0016	48.9	-	52.8	-	26.4	-	-	-	-	-	-	-	-	-	0.0015	0.0000
2019	0.0061	0.0044	0.0039	0.0028	25.8	-	27.8	-	13.9	0.0039	0.0029	0.0025	0.0018	31.0	-	33.5	-	16.8	0.0024	0.0015
2020	0.0070	0.0052	0.0049	0.0034	31.3	-	33.8	-	16.9	0.0065	0.0048	0.0046	0.0031	38.7	-	41.8	-	20.9	0.0026	0.0023
2021	0.0074	0.0055	0.0060	0.0040	5.2	-	5.6	-	2.8	0.0073	0.0054	0.0059	0.0039	7.0	-	7.5	-	3.8	0.0027	0.0024
2022	0.0066	0.0047	0.0053	0.0034	3.5	-	3.8	-	1.9	0.0073	0.0052	0.0059	0.0037	5.3	-	5.7	-	2.8	0.0024	0.0024
2023	0.0054	0.0038	0.0040	0.0025	-	3.3	-	4.0	2.0	0.0068	0.0047	0.0050	0.0031	3.5	-	3.8	-	1.9	0.0018	0.0018
2024	0.0043	0.0033	0.0029	0.0021	-	5.8	-	6.9	3.5	0.0056	0.0042	0.0038	0.0027	-	3.4	-	4.0	2.0	0.0011	0.0011
2025	0.0029	0.0022	0.0022	0.0016	-	95.6	-	113.2	56.6	0.0040	0.0030	0.0030	0.0022	-	74.9	-	88.8	44.4	0.0009	0.0009
2026	0.0016	0.0011	0.0013	0.0009	-	112.8	-	133.6	66.8	0.0029	0.0021	0.0024	0.0016	-	102.0	-	120.9	60.4	0.0006	0.0006
2027	0.0009	0.0007	0.0007	0.0005	-	110.4	-	130.9	65.4	0.0016	0.0012	0.0012	0.0008	-	118.7	-	140.7	70.4	0.0003	0.0003
2028	-	-	-	-	-	84.6	-	100.2	50.1	0.0009	0.0007	0.0007	0.0005	-	116.6	-	138.2	69.1	0.0001	0.0001
2029	-	-	-	-	-	55.6	-	65.9	33.0	-	-	-	-	-	89.9	-	106.5	53.3	0.0001	0.0001
2030	-	-	-	-	-	27.1	-	32.1	16.0	-	-	-	-	-	49.5	-	58.7	29.4	0.0001	0.0001
2031	-	-	-	-	-	12.7	-	15.0	7.5	-	-	-	-	-	28.6	-	33.9	16.9	0.0001	0.0001
2032	-	-	-	-	-	3.7	-	4.3	2.2	-	-	-	-	-	13.4	-	15.9	8.0	0.0001	0.0001
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3.3	-	3.9	1.9	0.0001	0.0001
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
Levelized Costs																				
10 years (2018-2027)	0.0047	0.0034	0.0034	0.0023	12.0	33.0	13.0	39.1	25.0	0.0046	0.0034	0.0034	0.0023	8.8	30.4	9.5	36.1	21.6	0.0017	0.0013
15 years (2018-2032)	0.0032	0.0024	0.0024	0.0016	8.3	35.0	8.9	41.4	24.1	0.0032	0.0024	0.0024	0.0016	6.1	41.0	6.6	48.6	26.0	0.0012	0.0010
30 years (2018-2047)	0.0018	0.0013	0.0013	0.0009	4.5	19.2	4.9	22.8	13.3	0.0018	0.0013	0.0013	0.0009	3.3	22.7	3.6	26.9	14.4	0.0007	0.0006

NOTES:

All Avoided Costs are in 2018 Dollars

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1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: New Hampshire

	Rest-of-Pool																		
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures									
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)	
2018	0.0348	0.0246	0.0238	0.0156	438.0	-	473.1	-	236.5	-	-	-	-	-	-	-	-	-	
2019	0.0543	0.0381	0.0362	0.0263	229.2	-	247.6	-	123.8	0.0350	0.0246	0.0234	0.0170	276.2	-	298.3	-	149.1	
2020	0.0621	0.0450	0.0459	0.0320	279.1	-	301.4	-	150.7	0.0575	0.0417	0.0425	0.0296	345.7	-	373.4	-	186.7	
2021	0.0651	0.0470	0.0556	0.0376	46.5	-	50.2	-	25.1	0.0640	0.0462	0.0547	0.0370	62.3	-	67.3	-	33.6	
2022	0.0582	0.0406	0.0494	0.0318	31.1	-	33.6	-	16.8	0.0641	0.0447	0.0544	0.0350	47.1	-	50.9	-	25.4	
2023	0.0432	0.0293	0.0334	0.0211	-	29.8	-	35.3	17.7	0.0543	0.0368	0.0420	0.0266	31.3	-	33.8	-	16.9	
2024	0.0349	0.0256	0.0248	0.0184	-	52.0	-	61.7	30.8	0.0451	0.0330	0.0319	0.0237	-	30.2	-	35.8	17.9	
2025	0.0233	0.0171	0.0185	0.0135	-	854.7	-	1012.9	506.4	0.0320	0.0235	0.0254	0.0185	-	670.3	-	794.4	397.2	
2026	0.0122	0.0088	0.0105	0.0073	-	1009.3	-	1196.1	598.1	0.0225	0.0162	0.0194	0.0136	-	912.9	-	1081.8	540.9	
2027	0.0075	0.0055	0.0057	0.0040	-	988.4	-	1171.4	585.7	0.0126	0.0092	0.0096	0.0067	-	1062.8	-	1259.5	629.8	
2028	0.0000	0.0000	0.0000	0.0000	-	757.1	-	897.3	448.6	0.0074	0.0051	0.0060	0.0040	-	1044.0	-	1237.2	618.6	
2029	0.0000	0.0000	0.0000	0.0000	-	497.9	-	590.1	295.0	-	-	-	-	-	804.8	-	953.7	476.9	
2030	-	-	-	-	-	242.4	-	287.2	143.6	-	-	-	-	-	443.5	-	525.6	262.8	
2031	-	-	-	-	-	113.2	-	134.2	67.1	-	-	-	-	-	256.0	-	303.4	151.7	
2032	-	-	-	-	-	32.8	-	38.9	19.4	-	-	-	-	-	120.4	-	142.6	71.3	
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	29.2	-	34.6	17.3	
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Levelized Costs																			
10 years (2018-2027)	0.0401	0.0285	0.0308	0.0210	107.2	295.3	115.8	349.9	223.7	0.0388	0.0277	0.0304	0.0208	78.8	272.4	85.1	322.8	193.6	
15 years (2018-2032)	0.0276	0.0196	0.0212	0.0145	73.8	312.9	79.7	370.8	215.6	0.0272	0.0194	0.0213	0.0146	54.3	367.4	58.6	435.3	232.9	
30 years (2018-2047)	0.0152	0.0108	0.0116	0.0080	40.6	172.1	43.8	203.9	118.6	0.0150	0.0107	0.0117	0.0080	29.9	203.0	32.2	240.6	128.7	

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: New Hampshire

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Rhode Island

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0476	0.0434	0.0319	0.0260	0.0028	0.0544	0.0499	0.0375	0.0310	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0496	0.0453	0.0320	0.0284	0.0061	0.0601	0.0555	0.0411	0.0373	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0520	0.0487	0.0380	0.0328	0.0060	0.0627	0.0591	0.0475	0.0420	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0551	0.0506	0.0458	0.0379	0.0048	0.0647	0.0598	0.0546	0.0461	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0545	0.0490	0.0448	0.0361	0.0019	0.0609	0.0550	0.0505	0.0411	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0552	0.0494	0.0419	0.0329	0.0023	0.0621	0.0558	0.0477	0.0380	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0590	0.0550	0.0412	0.0375	0.0021	0.0660	0.0617	0.0468	0.0428	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0555	0.0522	0.0432	0.0387	0.0017	0.0618	0.0582	0.0485	0.0436	65.7	53.9	70.9	63.9	67.4	0.0421	0.0429	0.0410	0.0412
2026	0.0554	0.0519	0.0470	0.0410	0.0015	0.0615	0.0577	0.0523	0.0459	71.2	74.9	76.9	88.7	82.8	0.0417	0.0426	0.0406	0.0409
2027	0.0600	0.0561	0.0448	0.0389	0.0013	0.0661	0.0619	0.0498	0.0434	76.9	89.5	83.0	106.1	94.5	0.0414	0.0423	0.0403	0.0406
2028	0.0617	0.0544	0.0489	0.0399	0.0010	0.0678	0.0599	0.0540	0.0442	82.5	94.8	89.1	112.3	100.7	0.0411	0.0420	0.0401	0.0403
2029	0.0636	0.0582	0.0479	0.0406	0.0009	0.0696	0.0639	0.0527	0.0448	88.1	101.0	95.2	119.7	107.4	0.0408	0.0417	0.0398	0.0400
2030	0.0585	0.0552	0.0506	0.0463	0.0008	0.0640	0.0604	0.0555	0.0508	83.9	97.7	90.6	115.8	103.2	0.0403	0.0412	0.0393	0.0395
2031	0.0582	0.0544	0.0462	0.0400	0.0007	0.0636	0.0596	0.0506	0.0440	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0569	0.0528	0.0470	0.0406	0.0012	0.0628	0.0584	0.0521	0.0452	88.1	101.0	95.2	119.7	107.4	0.0394	0.0402	0.0384	0.0386
2033	0.0615	0.0540	0.0478	0.0389	0.0013	0.0678	0.0597	0.0530	0.0434	83.9	97.7	90.6	115.8	103.2	0.0390	0.0398	0.0380	0.0382
2034	0.0605	0.0507	0.0505	0.0397	0.0013	0.0667	0.0562	0.0560	0.0443	82.5	94.8	89.1	112.3	100.7	0.0386	0.0394	0.0376	0.0378
2035	0.0625	0.0558	0.0563	0.0476	0.0014	0.0690	0.0618	0.0623	0.0530	88.1	101.0	95.2	119.7	107.4	0.0382	0.0390	0.0372	0.0374
2036	0.0636	0.0562	0.0591	0.0498	0.0017	0.0705	0.0625	0.0656	0.0555	89.6	102.6	96.8	121.6	109.2	0.0378	0.0386	0.0368	0.0370
2037	0.0648	0.0565	0.0621	0.0520	0.0020	0.0721	0.0632	0.0692	0.0582	91.1	104.3	98.4	123.6	111.0	0.0374	0.0381	0.0364	0.0366
2038	0.0659	0.0569	0.0653	0.0543	0.0023	0.0737	0.0639	0.0730	0.0611	92.6	105.9	100.0	125.5	112.8	0.0369	0.0377	0.0360	0.0362
2039	0.0671	0.0572	0.0686	0.0567	0.0028	0.0755	0.0648	0.0770	0.0642	94.2	107.6	101.7	127.5	114.6	0.0366	0.0373	0.0356	0.0358
2040	0.0683	0.0576	0.0721	0.0592	0.0033	0.0773	0.0657	0.0814	0.0675	95.7	109.3	103.4	129.6	116.5	0.0362	0.0369	0.0352	0.0354
2041	0.0695	0.0580	0.0757	0.0618	0.0039	0.0793	0.0668	0.0860	0.0709	97.3	111.1	105.1	131.7	118.4	0.0358	0.0365	0.0348	0.0351
2042	0.0708	0.0583	0.0795	0.0645	0.0046	0.0814	0.0680	0.0909	0.0747	98.9	112.9	106.9	133.8	120.3	0.0354	0.0361	0.0345	0.0347
2043	0.0721	0.0587	0.0836	0.0674	0.0055	0.0837	0.0693	0.0962	0.0787	100.6	114.7	108.6	135.9	122.3	0.0350	0.0357	0.0341	0.0343
2044	0.0733	0.0591	0.0878	0.0704	0.0065	0.0862	0.0708	0.1019	0.0830	102.3	116.5	110.5	138.1	124.3	0.0346	0.0354	0.0337	0.0339
2045	0.0747	0.0594	0.0923	0.0735	0.0077	0.0889	0.0725	0.1080	0.0877	104.0	118.4	112.3	140.3	126.3	0.0342	0.0350	0.0334	0.0336
2046	0.0760	0.0598	0.0970	0.0768	0.0091	0.0919	0.0745	0.1146	0.0928	105.7	120.3	114.2	142.5	128.3	0.0339	0.0346	0.0330	0.0332
2047	0.0774	0.0602	0.1019	0.0802	0.0108	0.0953	0.0767	0.1217	0.0983	107.5	122.2	116.1	144.8	130.4	0.0335	0.0342	0.0326	0.0329
2048	0.0787	0.0606	0.1070	0.0837	0.0129	0.0989	0.0793	0.1295	0.1043	109.3	124.2	118.0	147.1	132.6	0.0332	0.0339	0.0323	0.0325
2049	0.0802	0.0610	0.1125	0.0875	0.0153	0.1031	0.0823	0.1380	0.1109	111.1	126.1	120.0	149.5	134.7	0.0328	0.0335	0.0319	0.0322
2050	0.0816	0.0613	0.1182	0.0913	0.0181	0.1077	0.0858	0.1472	0.1182	112.9	128.2	122.0	151.9	136.9	0.0324	0.0331	0.0316	0.0318
Levelized Costs																		
10 years (2018-2027)	0.0543	0.0500	0.0409	0.0349	0.0031	0.0620	0.0574	0.0475	0.0410	73.3	26.4	79.2	31.2	55.2	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0560	0.0516	0.0432	0.0369	0.0024	0.0631	0.0583	0.0492	0.0425	76.9	48.6	83.1	57.6	70.4	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0615	0.0541	0.0563	0.0468	0.0032	0.0699	0.0618	0.0642	0.0540	85.1	75.7	92.0	89.7	90.8	0.0396	0.0404	0.0385	0.0388

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Rhode Island

	Intrastate																		Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures										
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0028	0.0019	0.0019	0.0012	10.0	-	10.8	-	5.4	-	-	-	-	-	-	-	-	-	0.0011	0.0000
2019	0.0044	0.0030	0.0029	0.0020	5.0	-	5.4	-	2.7	0.0028	0.0019	0.0019	0.0013	6.0	-	6.5	-	3.2	0.0017	0.0011
2020	0.0049	0.0035	0.0037	0.0025	6.1	-	6.6	-	3.3	0.0046	0.0032	0.0034	0.0023	7.6	-	8.2	-	4.1	0.0019	0.0017
2021	0.0052	0.0036	0.0045	0.0029	1.1	-	1.2	-	0.6	0.0051	0.0036	0.0044	0.0028	1.5	-	1.7	-	0.8	0.0019	0.0017
2022	0.0046	0.0031	0.0040	0.0024	0.8	-	0.9	-	0.4	0.0051	0.0035	0.0044	0.0027	1.3	-	1.4	-	0.7	0.0017	0.0017
2023	0.0038	0.0025	0.0030	0.0018	-	0.8	-	0.9	0.5	0.0048	0.0031	0.0037	0.0022	0.8	-	0.9	-	0.5	0.0013	0.0013
2024	0.0030	0.0022	0.0022	0.0015	-	1.4	-	1.7	0.8	0.0039	0.0028	0.0028	0.0020	-	0.8	-	1.0	0.5	0.0008	0.0008
2025	0.0020	0.0015	0.0016	0.0011	-	23.1	-	27.4	13.7	0.0028	0.0020	0.0023	0.0016	-	18.1	-	21.5	10.7	0.0006	0.0006
2026	0.0011	0.0008	0.0009	0.0006	-	27.5	-	32.6	16.3	0.0020	0.0014	0.0018	0.0012	-	24.9	-	29.5	14.7	0.0004	0.0004
2027	0.0007	0.0005	0.0005	0.0003	-	26.9	-	31.9	15.9	0.0011	0.0008	0.0009	0.0006	-	28.9	-	34.3	17.1	0.0003	0.0003
2028	-	-	-	-	-	20.6	-	24.4	12.2	0.0007	0.0004	0.0005	0.0003	-	28.4	-	33.7	16.8	0.0001	0.0001
2029	-	-	-	-	-	13.6	-	16.1	8.0	-	-	-	-	-	21.9	-	26.0	13.0	0.0001	0.0001
2030	-	-	-	-	-	6.6	-	7.8	3.9	-	-	-	-	-	12.1	-	14.3	7.2	0.0001	0.0001
2031	-	-	-	-	-	3.1	-	3.7	1.8	-	-	-	-	-	7.0	-	8.3	4.1	0.0001	0.0001
2032	-	-	-	-	-	0.9	-	1.1	0.5	-	-	-	-	-	3.3	-	3.9	1.9	0.0001	0.0001
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.8	-	0.9	0.5	0.0001	0.0001
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0001	0.0001
Levelized Costs																				
10 years (2018-2027)	0.0033	0.0023	0.0026	0.0017	2.4	8.0	2.6	9.5	5.8	0.0032	0.0022	0.0026	0.0017	1.8	7.4	1.9	8.8	5.1	0.0012	0.0010
15 years (2018-2032)	0.0023	0.0016	0.0018	0.0011	1.7	8.5	1.8	10.1	5.7	0.0023	0.0016	0.0018	0.0012	1.2	10.0	1.3	11.8	6.2	0.0008	0.0007
30 years (2018-2047)	0.0012	0.0009	0.0010	0.0006	0.9	4.7	1.0	5.5	3.1	0.0012	0.0009	0.0010	0.0006	0.7	5.5	0.7	6.5	3.4	0.0005	0.0004

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Rhode Island

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0359	0.0255	0.0244	0.0160	477.0	-	515.1	-	257.6	-	-	-	-	-	-	-	-	-
2019	0.0560	0.0395	0.0372	0.0270	250.0	-	270.0	-	135.0	0.0361	0.0255	0.0240	0.0174	301.2	-	325.3	-	162.7
2020	0.0642	0.0467	0.0471	0.0329	304.2	-	328.5	-	164.3	0.0594	0.0433	0.0436	0.0305	376.8	-	407.0	-	203.5
2021	0.0673	0.0488	0.0572	0.0387	50.5	-	54.6	-	27.3	0.0662	0.0480	0.0563	0.0381	67.7	-	73.2	-	36.6
2022	0.0601	0.0422	0.0507	0.0327	33.7	-	36.4	-	18.2	0.0663	0.0465	0.0559	0.0360	51.1	-	55.2	-	27.6
2023	0.0448	0.0306	0.0344	0.0219	-	32.3	-	38.3	19.2	0.0564	0.0384	0.0433	0.0275	34.0	-	36.7	-	18.3
2024	0.0362	0.0267	0.0255	0.0190	-	56.5	-	66.9	33.5	0.0468	0.0344	0.0329	0.0245	-	32.8	-	38.8	19.4
2025	0.0242	0.0178	0.0191	0.0139	-	927.1	-	1098.7	549.4	0.0333	0.0246	0.0262	0.0192	-	727.1	-	861.7	430.8
2026	0.0126	0.0091	0.0108	0.0076	-	1094.6	-	1297.2	648.6	0.0234	0.0169	0.0200	0.0141	-	990.0	-	1173.2	586.6
2027	0.0078	0.0057	0.0059	0.0041	-	1072.0	-	1270.3	635.2	0.0131	0.0096	0.0099	0.0070	-	1152.6	-	1365.9	683.0
2028	0.0000	0.0000	0.0000	0.0000	-	821.1	-	973.1	486.5	0.0077	0.0053	0.0062	0.0041	-	1132.2	-	1341.8	670.9
2029	0.0000	0.0000	0.0000	0.0000	-	540.0	-	639.9	320.0	-	-	-	-	-	872.8	-	1034.3	517.1
2030	-	-	-	-	-	262.9	-	311.5	155.8	-	-	-	-	-	481.0	-	570.0	285.0
2031	-	-	-	-	-	122.8	-	145.5	72.8	-	-	-	-	-	277.6	-	329.0	164.5
2032	-	-	-	-	-	35.6	-	42.2	21.1	-	-	-	-	-	130.5	-	154.7	77.3
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	31.7	-	37.6	18.8
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Levelized Costs																		
10 years (2018-2027)	0.0415	0.0297	0.0316	0.0217	116.8	320.3	126.1	379.5	243.0	0.0402	0.0288	0.0313	0.0215	85.9	295.4	92.8	350.1	210.1
15 years (2018-2032)	0.0286	0.0204	0.0218	0.0149	80.4	339.4	86.8	402.2	234.1	0.0282	0.0202	0.0219	0.0150	59.1	398.4	63.9	472.1	252.8
30 years (2018-2047)	0.0157	0.0112	0.0120	0.0082	44.2	186.6	47.8	221.1	128.7	0.0155	0.0111	0.0121	0.0083	32.5	220.2	35.1	260.9	139.6

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **Rhode Island**

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **Vermont**

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0473	0.0431	0.0315	0.0256	0.0019	0.0547	0.0500	0.0372	0.0306	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0481	0.0446	0.0314	0.0281	0.0037	0.0576	0.0537	0.0391	0.0353	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0515	0.0483	0.0372	0.0324	0.0036	0.0612	0.0577	0.0454	0.0400	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0537	0.0502	0.0448	0.0374	0.0035	0.0636	0.0597	0.0538	0.0455	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0533	0.0484	0.0442	0.0357	0.0021	0.0615	0.0561	0.0514	0.0420	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0548	0.0485	0.0414	0.0325	0.0019	0.0630	0.0560	0.0481	0.0382	58.8	20.8	63.5	25.3	44.4	0.0428	0.0437	0.0417	0.0419
2024	0.0580	0.0545	0.0408	0.0371	0.0018	0.0665	0.0625	0.0474	0.0433	61.2	36.0	66.1	43.9	55.0	0.0424	0.0433	0.0413	0.0416
2025	0.0549	0.0519	0.0427	0.0382	0.0016	0.0628	0.0595	0.0493	0.0442	65.7	53.9	70.9	65.7	68.3	0.0421	0.0429	0.0410	0.0412
2026	0.0551	0.0516	0.0463	0.0406	0.0015	0.0629	0.0591	0.0532	0.0468	71.2	74.9	76.9	91.3	84.1	0.0417	0.0426	0.0406	0.0409
2027	0.0595	0.0558	0.0443	0.0385	0.0014	0.0677	0.0635	0.0507	0.0443	76.9	89.5	83.0	109.1	96.1	0.0414	0.0423	0.0403	0.0406
2028	0.0614	0.0542	0.0486	0.0396	0.0012	0.0696	0.0616	0.0553	0.0454	82.5	94.8	89.1	115.5	102.3	0.0411	0.0420	0.0401	0.0403
2029	0.0633	0.0580	0.0475	0.0401	0.0012	0.0717	0.0657	0.0541	0.0459	88.1	101.0	95.2	123.1	109.2	0.0408	0.0417	0.0398	0.0400
2030	0.0582	0.0549	0.0501	0.0457	0.0011	0.0658	0.0622	0.0569	0.0520	83.9	97.7	90.6	119.2	104.9	0.0403	0.0412	0.0393	0.0395
2031	0.0577	0.0541	0.0454	0.0396	0.0010	0.0653	0.0613	0.0516	0.0452	82.5	94.8	89.1	115.5	102.3	0.0399	0.0407	0.0388	0.0391
2032	0.0563	0.0525	0.0464	0.0403	0.0014	0.0642	0.0599	0.0531	0.0463	88.1	101.0	95.2	123.1	109.2	0.0394	0.0402	0.0384	0.0386
2033	0.0610	0.0536	0.0471	0.0386	0.0015	0.0694	0.0612	0.0540	0.0445	83.9	97.7	90.6	119.2	104.9	0.0390	0.0398	0.0380	0.0382
2034	0.0601	0.0505	0.0502	0.0394	0.0015	0.0685	0.0578	0.0574	0.0455	82.5	94.8	89.1	115.5	102.3	0.0386	0.0394	0.0376	0.0378
2035	0.0622	0.0555	0.0558	0.0471	0.0016	0.0708	0.0634	0.0637	0.0540	88.1	101.0	95.2	123.1	109.2	0.0382	0.0390	0.0372	0.0374
2036	0.0634	0.0558	0.0587	0.0491	0.0018	0.0723	0.0640	0.0672	0.0565	89.6	102.6	96.8	125.1	110.9	0.0378	0.0386	0.0368	0.0370
2037	0.0645	0.0562	0.0618	0.0513	0.0019	0.0739	0.0646	0.0708	0.0591	91.1	104.3	98.4	127.1	112.7	0.0374	0.0381	0.0364	0.0366
2038	0.0658	0.0565	0.0651	0.0536	0.0022	0.0754	0.0652	0.0747	0.0619	92.6	105.9	100.0	129.1	114.6	0.0369	0.0377	0.0360	0.0362
2039	0.0670	0.0569	0.0685	0.0559	0.0024	0.0771	0.0659	0.0788	0.0648	94.2	107.6	101.7	131.2	116.4	0.0366	0.0373	0.0356	0.0358
2040	0.0682	0.0572	0.0721	0.0584	0.0027	0.0788	0.0665	0.0831	0.0678	95.7	109.3	103.4	133.3	118.3	0.0362	0.0369	0.0352	0.0354
2041	0.0695	0.0576	0.0759	0.0609	0.0029	0.0805	0.0673	0.0876	0.0710	97.3	111.1	105.1	135.4	120.3	0.0358	0.0365	0.0348	0.0351
2042	0.0708	0.0580	0.0799	0.0636	0.0033	0.0823	0.0680	0.0924	0.0743	98.9	112.9	106.9	137.6	122.2	0.0354	0.0361	0.0345	0.0347
2043	0.0722	0.0583	0.0841	0.0664	0.0036	0.0842	0.0688	0.0975	0.0778	100.6	114.7	108.6	139.8	124.2	0.0350	0.0357	0.0341	0.0343
2044	0.0735	0.0587	0.0886	0.0693	0.0040	0.0861	0.0697	0.1029	0.0815	102.3	116.5	110.5	142.0	126.2	0.0346	0.0354	0.0337	0.0339
2045	0.0749	0.0590	0.0932	0.0724	0.0045	0.0882	0.0706	0.1086	0.0854	104.0	118.4	112.3	144.3	128.3	0.0342	0.0350	0.0334	0.0336
2046	0.0763	0.0594	0.0982	0.0756	0.0050	0.0903	0.0715	0.1146	0.0895	105.7	120.3	114.2	146.6	130.4	0.0339	0.0346	0.0330	0.0332
2047	0.0777	0.0598	0.1033	0.0789	0.0055	0.0925	0.0725	0.1209	0.0938	107.5	122.2	116.1	149.0	132.5	0.0335	0.0342	0.0326	0.0329
2048	0.0792	0.0602	0.1088	0.0824	0.0061	0.0948	0.0736	0.1276	0.0983	109.3	124.2	118.0	151.4	134.7	0.0332	0.0339	0.0323	0.0325
2049	0.0807	0.0605	0.1145	0.0860	0.0068	0.0972	0.0748	0.1348	0.1031	111.1	126.1	120.0	153.8	136.9	0.0328	0.0335	0.0319	0.0322
2050	0.0822	0.0609	0.1206	0.0898	0.0075	0.0997	0.0760	0.1423	0.1081	112.9	128.2	122.0	156.2	139.1	0.0324	0.0331	0.0316	0.0318
Levelized Costs																		
10 years (2018-2027)	0.0535	0.0496	0.0403	0.0345	0.0023	0.0620	0.0577	0.0474	0.0409	73.3	26.4	79.2	32.1	55.6	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0553	0.0512	0.0426	0.0365	0.0020	0.0637	0.0591	0.0495	0.0428	76.9	48.6	83.1	59.3	71.2	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0611	0.0537	0.0561	0.0462	0.0024	0.0705	0.0623	0.0649	0.0540	85.1	75.7	92.0	92.3	92.1	0.0396	0.0404	0.0385	0.0388

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 11.1%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 11.1%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 11.1%, and Wholesale Risk Premium of 11.1%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Vermont

	Intrastate																		Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures										
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0008	0.0006	0.0005	0.0003	4.8	-	5.3	-	2.6	-	-	-	-	-	-	-	-	-	0.0003	0.0000
2019	0.0012	0.0009	0.0007	0.0005	2.4	-	2.6	-	1.3	0.0008	0.0006	0.0005	0.0003	2.8	-	3.2	-	1.6	0.0005	0.0003
2020	0.0014	0.0010	0.0009	0.0006	2.9	-	3.2	-	1.6	0.0013	0.0010	0.0009	0.0006	3.6	-	4.0	-	2.0	0.0005	0.0005
2021	0.0015	0.0011	0.0011	0.0008	0.5	-	0.6	-	0.3	0.0015	0.0011	0.0011	0.0007	0.7	-	0.8	-	0.4	0.0005	0.0005
2022	0.0013	0.0009	0.0010	0.0006	0.4	-	0.4	-	0.2	0.0015	0.0010	0.0011	0.0007	0.6	-	0.6	-	0.3	0.0005	0.0005
2023	0.0011	0.0008	0.0007	0.0005	-	0.4	-	0.4	0.2	0.0014	0.0009	0.0009	0.0006	0.4	-	0.4	-	0.2	0.0003	0.0003
2024	0.0009	0.0007	0.0006	0.0004	-	0.6	-	0.8	0.4	0.0011	0.0008	0.0007	0.0005	-	0.4	-	0.5	0.2	0.0002	0.0002
2025	0.0006	0.0004	0.0004	0.0003	-	10.4	-	12.7	6.4	0.0008	0.0006	0.0006	0.0004	-	8.2	-	10.0	5.0	0.0002	0.0002
2026	0.0003	0.0002	0.0002	0.0002	-	12.3	-	15.0	7.5	0.0006	0.0004	0.0005	0.0003	-	11.1	-	13.6	6.8	0.0001	0.0001
2027	0.0002	0.0001	0.0001	0.0001	-	12.1	-	14.7	7.4	0.0003	0.0002	0.0002	0.0002	-	13.0	-	15.8	7.9	0.0001	0.0001
2028	-	-	-	-	-	9.2	-	11.3	5.6	0.0002	0.0001	0.0001	0.0001	-	12.8	-	15.5	7.8	0.0000	0.0000
2029	-	-	-	-	-	6.1	-	7.4	3.7	-	-	-	-	-	9.8	-	12.0	6.0	0.0000	0.0000
2030	-	-	-	-	-	3.0	-	3.6	1.8	-	-	-	-	-	5.4	-	6.6	3.3	0.0000	0.0000
2031	-	-	-	-	-	1.4	-	1.7	0.8	-	-	-	-	-	3.1	-	3.8	1.9	0.0000	0.0000
2032	-	-	-	-	-	0.4	-	0.5	0.2	-	-	-	-	-	1.5	-	1.8	0.9	0.0000	0.0000
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.4	-	0.4	0.2	0.0000	0.0000
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0000	0.0000
Levelized Costs																				
10 years (2018-2027)	0.0009	0.0007	0.0006	0.0004	1.1	3.6	1.3	4.4	2.7	0.0009	0.0007	0.0006	0.0004	0.8	3.3	0.9	4.1	2.4	0.0003	0.0003
15 years (2018-2032)	0.0007	0.0005	0.0004	0.0003	0.8	3.8	0.9	4.7	2.6	0.0007	0.0005	0.0005	0.0003	0.6	4.5	0.6	5.5	2.9	0.0002	0.0002
30 years (2018-2047)	0.0004	0.0003	0.0002	0.0002	0.4	2.1	0.5	2.6	1.5	0.0004	0.0003	0.0002	0.0002	0.3	2.5	0.4	3.0	1.6	0.0001	0.0001

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 11.1%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 11.1%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 11.1%, and Wholesale Risk Premium of 11.1%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Vermont

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0379	0.0268	0.0258	0.0169	482.2	-	535.7	-	267.9	-	-	-	-	-	-	-	-	-
2019	0.0592	0.0416	0.0394	0.0285	252.6	-	280.7	-	140.3	0.0382	0.0269	0.0254	0.0184	304.4	-	338.2	-	169.1
2020	0.0677	0.0492	0.0499	0.0347	307.5	-	341.6	-	170.8	0.0627	0.0456	0.0462	0.0322	380.9	-	423.2	-	211.6
2021	0.0710	0.0514	0.0605	0.0408	51.2	-	56.8	-	28.4	0.0698	0.0506	0.0596	0.0402	68.6	-	76.2	-	38.1
2022	0.0634	0.0444	0.0537	0.0345	34.2	-	38.0	-	19.0	0.0699	0.0489	0.0591	0.0380	51.8	-	57.5	-	28.8
2023	0.0475	0.0323	0.0367	0.0232	-	32.8	-	40.0	20.0	0.0597	0.0406	0.0461	0.0291	34.4	-	38.2	-	19.1
2024	0.0384	0.0282	0.0271	0.0201	-	57.2	-	69.8	34.9	0.0495	0.0364	0.0350	0.0260	-	33.2	-	40.5	20.2
2025	0.0256	0.0189	0.0203	0.0148	-	939.8	-	1145.7	572.9	0.0352	0.0260	0.0279	0.0203	-	737.1	-	898.5	449.3
2026	0.0134	0.0097	0.0115	0.0081	-	1109.8	-	1352.9	676.4	0.0248	0.0179	0.0213	0.0149	-	1003.7	-	1223.6	611.8
2027	0.0082	0.0060	0.0063	0.0044	-	1086.8	-	1324.9	662.4	0.0139	0.0102	0.0106	0.0074	-	1168.6	-	1424.6	712.3
2028	0.0000	0.0000	0.0000	0.0000	-	832.5	-	1014.9	507.4	0.0081	0.0056	0.0066	0.0044	-	1147.9	-	1399.4	699.7
2029	0.0000	0.0000	0.0000	0.0000	-	547.5	-	667.4	333.7	-	-	-	-	-	884.9	-	1078.7	539.4
2030	-	-	-	-	-	266.5	-	324.9	162.4	-	-	-	-	-	487.6	-	594.5	297.2
2031	-	-	-	-	-	124.5	-	151.8	75.9	-	-	-	-	-	281.5	-	343.2	171.6
2032	-	-	-	-	-	36.1	-	44.0	22.0	-	-	-	-	-	132.3	-	161.3	80.7
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	32.1	-	39.2	19.6
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Levelized Costs																		
10 years (2018-2027)	0.0438	0.0313	0.0335	0.0229	118.0	324.7	131.1	395.8	253.2	0.0425	0.0304	0.0332	0.0227	86.8	299.5	96.5	365.1	219.0
15 years (2018-2032)	0.0302	0.0215	0.0231	0.0158	81.3	344.0	90.3	419.4	244.0	0.0298	0.0213	0.0233	0.0159	59.8	403.9	66.4	492.4	263.5
30 years (2018-2047)	0.0166	0.0118	0.0127	0.0087	44.7	189.2	49.7	230.6	134.1	0.0164	0.0117	0.0128	0.0087	32.9	223.2	36.5	272.1	145.6

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 11.1%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 11.1%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 11.1%, and Wholesale Risk Premium of 11.1%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Vermont

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 11.1%)
2 Uncleared capacity value includes reserve margin and uncleared load forecast effect
3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4 Proceeds from selling into the FCM also include the ISO New England loss factor of 11.1%
5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 11.1%, and Wholesale Risk Premium of 11.1%
6 Assumes bid percentage of 50.0%
7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **Connecticut**

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0479	0.0438	0.0318	0.0258	0.0053	0.0574	0.0530	0.0401	0.0336	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0487	0.0453	0.0318	0.0284	0.0109	0.0644	0.0607	0.0461	0.0425	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0520	0.0489	0.0376	0.0327	0.0085	0.0654	0.0620	0.0498	0.0446	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0544	0.0507	0.0454	0.0378	0.0062	0.0654	0.0615	0.0558	0.0476	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0540	0.0490	0.0446	0.0359	0.0034	0.0620	0.0566	0.0518	0.0425	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0553	0.0490	0.0417	0.0327	0.0038	0.0638	0.0570	0.0491	0.0394	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0588	0.0552	0.0411	0.0374	0.0034	0.0672	0.0633	0.0480	0.0441	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0556	0.0525	0.0431	0.0386	0.0026	0.0628	0.0595	0.0493	0.0445	65.7	53.9	70.9	63.9	67.4	0.0421	0.0429	0.0410	0.0412
2026	0.0555	0.0521	0.0468	0.0410	0.0021	0.0623	0.0585	0.0528	0.0466	71.2	74.9	76.9	88.7	82.8	0.0417	0.0426	0.0406	0.0409
2027	0.0604	0.0564	0.0447	0.0389	0.0016	0.0670	0.0627	0.0501	0.0438	76.9	89.5	83.0	106.1	94.5	0.0414	0.0423	0.0403	0.0406
2028	0.0621	0.0549	0.0489	0.0399	0.0014	0.0686	0.0608	0.0544	0.0446	82.5	94.8	89.1	112.3	100.7	0.0411	0.0420	0.0401	0.0403
2029	0.0639	0.0586	0.0480	0.0406	0.0013	0.0704	0.0647	0.0532	0.0452	88.1	101.0	95.2	119.7	107.4	0.0408	0.0417	0.0398	0.0400
2030	0.0589	0.0556	0.0506	0.0462	0.0012	0.0648	0.0613	0.0559	0.0512	83.9	97.7	90.6	115.8	103.2	0.0403	0.0412	0.0393	0.0395
2031	0.0584	0.0548	0.0459	0.0401	0.0011	0.0643	0.0604	0.0508	0.0445	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0571	0.0531	0.0468	0.0406	0.0017	0.0634	0.0591	0.0524	0.0456	88.1	101.0	95.2	119.7	107.4	0.0394	0.0402	0.0384	0.0386
2033	0.0617	0.0543	0.0476	0.0389	0.0017	0.0685	0.0605	0.0532	0.0438	83.9	97.7	90.6	115.8	103.2	0.0390	0.0398	0.0380	0.0382
2034	0.0608	0.0512	0.0505	0.0397	0.0018	0.0676	0.0572	0.0565	0.0449	82.5	94.8	89.1	112.3	100.7	0.0386	0.0394	0.0376	0.0378
2035	0.0629	0.0562	0.0563	0.0477	0.0019	0.0699	0.0627	0.0628	0.0535	88.1	101.0	95.2	119.7	107.4	0.0382	0.0390	0.0372	0.0374
2036	0.0640	0.0566	0.0592	0.0498	0.0021	0.0714	0.0634	0.0662	0.0560	89.6	102.6	96.8	121.6	109.2	0.0378	0.0386	0.0368	0.0370
2037	0.0652	0.0569	0.0623	0.0520	0.0024	0.0730	0.0641	0.0699	0.0587	91.1	104.3	98.4	123.6	111.0	0.0374	0.0381	0.0364	0.0366
2038	0.0664	0.0573	0.0655	0.0543	0.0027	0.0747	0.0648	0.0737	0.0616	92.6	105.9	100.0	125.5	112.8	0.0369	0.0377	0.0360	0.0362
2039	0.0676	0.0577	0.0690	0.0567	0.0031	0.0764	0.0656	0.0778	0.0646	94.2	107.6	101.7	127.5	114.6	0.0366	0.0373	0.0356	0.0358
2040	0.0689	0.0581	0.0726	0.0592	0.0035	0.0782	0.0665	0.0822	0.0678	95.7	109.3	103.4	129.6	116.5	0.0362	0.0369	0.0352	0.0354
2041	0.0702	0.0585	0.0764	0.0619	0.0040	0.0801	0.0674	0.0868	0.0711	97.3	111.1	105.1	131.7	118.4	0.0358	0.0365	0.0348	0.0351
2042	0.0714	0.0588	0.0803	0.0646	0.0045	0.0820	0.0684	0.0916	0.0746	98.9	112.9	106.9	133.8	120.3	0.0354	0.0361	0.0345	0.0347
2043	0.0728	0.0592	0.0845	0.0675	0.0051	0.0841	0.0695	0.0968	0.0784	100.6	114.7	108.6	135.9	122.3	0.0350	0.0357	0.0341	0.0343
2044	0.0741	0.0596	0.0890	0.0705	0.0058	0.0863	0.0706	0.1023	0.0824	102.3	116.5	110.5	138.1	124.3	0.0346	0.0354	0.0337	0.0339
2045	0.0755	0.0600	0.0936	0.0736	0.0066	0.0886	0.0719	0.1082	0.0866	104.0	118.4	112.3	140.3	126.3	0.0342	0.0350	0.0334	0.0336
2046	0.0769	0.0604	0.0985	0.0769	0.0075	0.0911	0.0733	0.1144	0.0911	105.7	120.3	114.2	142.5	128.3	0.0339	0.0346	0.0330	0.0332
2047	0.0783	0.0608	0.1036	0.0803	0.0085	0.0937	0.0748	0.1211	0.0959	107.5	122.2	116.1	144.8	130.4	0.0335	0.0342	0.0326	0.0329
2048	0.0797	0.0612	0.1090	0.0839	0.0096	0.0965	0.0765	0.1281	0.1009	109.3	124.2	118.0	147.1	132.6	0.0332	0.0339	0.0323	0.0325
2049	0.0812	0.0616	0.1147	0.0876	0.0109	0.0995	0.0783	0.1357	0.1064	111.1	126.1	120.0	149.5	134.7	0.0328	0.0335	0.0319	0.0322
2050	0.0827	0.0620	0.1207	0.0915	0.0124	0.1027	0.0803	0.1437	0.1121	112.9	128.2	122.0	151.9	136.9	0.0324	0.0331	0.0316	0.0318

Levelized Costs																		
10 years (2018-2027)	0.0541	0.0502	0.0407	0.0348	0.0049	0.0637	0.0594	0.0492	0.0428	73.3	26.4	79.2	31.2	55.2	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0560	0.0518	0.0430	0.0369	0.0038	0.0645	0.0600	0.0505	0.0439	76.9	48.6	83.1	57.6	70.4	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0618	0.0544	0.0565	0.0468	0.0039	0.0709	0.0629	0.0652	0.0547	85.1	75.7	92.0	89.7	90.8	0.0396	0.0404	0.0385	0.0388

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Connecticut

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0080	0.0057	0.0057	0.0037	117.6	-	127.0	-	63.5	-	-	-	-	-	-	-	-	-	0.0032	0.0000
2019	0.0124	0.0088	0.0086	0.0062	61.1	-	66.0	-	33.0	0.0080	0.0057	0.0056	0.0040	73.6	-	79.5	-	39.7	0.0050	0.0031
2020	0.0142	0.0103	0.0109	0.0076	74.5	-	80.5	-	40.2	0.0131	0.0096	0.0100	0.0070	92.3	-	99.7	-	49.9	0.0055	0.0049
2021	0.0146	0.0106	0.0130	0.0087	12.4	-	13.3	-	6.7	0.0144	0.0104	0.0128	0.0086	16.6	-	17.9	-	8.9	0.0056	0.0050
2022	0.0131	0.0091	0.0115	0.0074	8.2	-	8.9	-	4.4	0.0144	0.0101	0.0127	0.0081	12.5	-	13.4	-	6.7	0.0050	0.0050
2023	0.0107	0.0072	0.0086	0.0054	-	7.9	-	9.3	4.7	0.0135	0.0091	0.0108	0.0068	8.2	-	8.9	-	4.4	0.0037	0.0037
2024	0.0086	0.0063	0.0063	0.0047	-	13.6	-	16.2	8.1	0.0112	0.0082	0.0082	0.0060	-	7.9	-	9.4	4.7	0.0024	0.0024
2025	0.0058	0.0043	0.0048	0.0035	-	224.5	-	266.1	133.0	0.0080	0.0059	0.0066	0.0048	-	176.1	-	208.7	104.3	0.0018	0.0018
2026	0.0031	0.0022	0.0027	0.0019	-	264.0	-	312.9	156.4	0.0057	0.0041	0.0051	0.0036	-	238.8	-	283.0	141.5	0.0013	0.0013
2027	0.0019	0.0014	0.0015	0.0010	-	258.5	-	306.4	153.2	0.0032	0.0023	0.0025	0.0017	-	278.0	-	329.5	164.7	0.0008	0.0008
2028	-	-	-	-	-	198.0	-	234.7	117.3	0.0019	0.0013	0.0016	0.0010	-	273.1	-	323.6	161.8	0.0003	0.0003
2029	-	-	-	-	-	130.2	-	154.3	77.2	-	-	-	-	-	210.5	-	249.5	124.7	0.0003	0.0003
2030	-	-	-	-	-	63.4	-	75.1	37.6	-	-	-	-	-	116.0	-	137.5	68.7	0.0003	0.0003
2031	-	-	-	-	-	29.6	-	35.1	17.5	-	-	-	-	-	67.0	-	79.4	39.7	0.0003	0.0003
2032	-	-	-	-	-	8.6	-	10.2	5.1	-	-	-	-	-	31.5	-	37.3	18.7	0.0003	0.0003
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.6	-	9.1	4.5	0.0003	0.0003
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
Levelized Costs																				
10 years (2018-2027)	0.0094	0.0067	0.0075	0.0051	28.7	77.3	30.9	91.7	58.9	0.0091	0.0065	0.0074	0.0051	21.0	71.3	22.7	84.5	50.9	0.0035	0.0028
15 years (2018-2032)	0.0064	0.0046	0.0051	0.0035	19.7	81.9	21.3	97.1	56.7	0.0064	0.0046	0.0052	0.0035	14.5	96.1	15.6	113.9	61.1	0.0025	0.0020
30 years (2018-2047)	0.0035	0.0025	0.0028	0.0019	10.9	45.0	11.7	53.4	31.2	0.0035	0.0025	0.0029	0.0020	8.0	53.1	8.6	63.0	33.7	0.0015	0.0012

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Connecticut

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0307	0.0217	0.0206	0.0136	369.4	-	398.9	-	199.5	-	-	-	-	-	-	-	-	-
2019	0.0480	0.0337	0.0315	0.0228	193.9	-	209.4	-	104.7	0.0309	0.0218	0.0203	0.0147	233.6	-	252.3	-	126.2
2020	0.0549	0.0399	0.0400	0.0278	235.8	-	254.7	-	127.3	0.0509	0.0369	0.0370	0.0258	292.1	-	315.5	-	157.8
2021	0.0578	0.0418	0.0486	0.0329	39.3	-	42.5	-	21.2	0.0569	0.0412	0.0479	0.0324	52.7	-	56.9	-	28.5
2022	0.0517	0.0362	0.0432	0.0278	26.3	-	28.5	-	14.2	0.0570	0.0399	0.0476	0.0306	39.9	-	43.1	-	21.6
2023	0.0379	0.0258	0.0288	0.0182	-	25.3	-	30.0	15.0	0.0476	0.0325	0.0362	0.0229	26.6	-	28.7	-	14.3
2024	0.0306	0.0225	0.0213	0.0158	-	44.2	-	52.4	26.2	0.0395	0.0290	0.0275	0.0205	-	25.7	-	30.4	15.2
2025	0.0204	0.0150	0.0159	0.0116	-	725.7	-	860.0	430.0	0.0281	0.0207	0.0219	0.0160	-	569.2	-	674.5	337.2
2026	0.0107	0.0077	0.0090	0.0063	-	858.1	-	1016.9	508.4	0.0198	0.0143	0.0167	0.0117	-	776.1	-	919.7	459.8
2027	0.0065	0.0048	0.0049	0.0034	-	840.3	-	995.8	497.9	0.0110	0.0081	0.0083	0.0058	-	903.6	-	1070.8	535.4
2028	0.0000	0.0000	0.0000	0.0000	-	643.7	-	762.8	381.4	0.0065	0.0045	0.0052	0.0035	-	887.6	-	1051.8	525.9
2029	0.0000	0.0000	0.0000	0.0000	-	423.3	-	501.6	250.8	-	-	-	-	-	684.2	-	810.8	405.4
2030	-	-	-	-	-	206.1	-	244.2	122.1	-	-	-	-	-	377.1	-	446.8	223.4
2031	-	-	-	-	-	96.3	-	114.1	57.0	-	-	-	-	-	217.7	-	257.9	129.0
2032	-	-	-	-	-	27.9	-	33.1	16.5	-	-	-	-	-	102.3	-	121.3	60.6
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.8	-	29.4	14.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0354	0.0253	0.0267	0.0183	90.5	250.9	97.8	297.4	189.8	0.0343	0.0245	0.0264	0.0181	66.7	231.5	72.0	274.3	164.3
15 years (2018-2032)	0.0244	0.0174	0.0184	0.0126	62.3	265.9	67.3	315.2	183.1	0.0240	0.0172	0.0185	0.0127	45.9	312.3	49.6	370.0	197.9
30 years (2018-2047)	0.0134	0.0096	0.0101	0.0069	34.3	146.2	37.0	173.3	100.7	0.0132	0.0094	0.0102	0.0070	25.2	172.6	27.3	204.5	109.3

NOTES:
All Avoided Costs are in 2018 Dollars
ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2. Uncleared capacity value includes reserve margin and uncleared load forecast effect
3. Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4. Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5. Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6. Assumes bid percentage of 50.0%
7. Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8. Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Connecticut

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

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3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: OTCT

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0479	0.0438	0.0318	0.0258	0.0053	0.0574	0.0531	0.0401	0.0336	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0487	0.0453	0.0318	0.0284	0.0109	0.0644	0.0607	0.0461	0.0425	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0520	0.0489	0.0376	0.0327	0.0085	0.0654	0.0620	0.0498	0.0446	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0544	0.0507	0.0454	0.0378	0.0062	0.0654	0.0615	0.0558	0.0476	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0540	0.0490	0.0446	0.0359	0.0034	0.0619	0.0566	0.0518	0.0425	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0553	0.0490	0.0417	0.0327	0.0038	0.0638	0.0570	0.0491	0.0394	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0588	0.0552	0.0411	0.0374	0.0034	0.0672	0.0633	0.0480	0.0441	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0556	0.0525	0.0431	0.0386	0.0026	0.0628	0.0595	0.0493	0.0444	65.7	53.9	70.9	63.9	67.4	0.0421	0.0429	0.0410	0.0412
2026	0.0555	0.0521	0.0468	0.0410	0.0021	0.0623	0.0585	0.0528	0.0466	71.2	74.9	76.9	88.7	82.8	0.0417	0.0426	0.0406	0.0409
2027	0.0604	0.0564	0.0447	0.0389	0.0016	0.0670	0.0627	0.0501	0.0438	76.9	89.5	83.0	106.1	94.5	0.0414	0.0423	0.0403	0.0406
2028	0.0621	0.0549	0.0489	0.0399	0.0014	0.0686	0.0608	0.0543	0.0446	82.5	94.8	89.1	112.3	100.7	0.0411	0.0420	0.0401	0.0403
2029	0.0639	0.0586	0.0479	0.0406	0.0013	0.0704	0.0647	0.0532	0.0452	88.1	101.0	95.2	119.7	107.4	0.0408	0.0417	0.0398	0.0400
2030	0.0589	0.0556	0.0506	0.0462	0.0012	0.0648	0.0613	0.0559	0.0512	83.9	97.7	90.6	115.8	103.2	0.0403	0.0412	0.0393	0.0395
2031	0.0584	0.0548	0.0459	0.0401	0.0011	0.0643	0.0604	0.0508	0.0445	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0571	0.0531	0.0468	0.0406	0.0017	0.0634	0.0591	0.0524	0.0456	88.1	101.0	95.2	119.7	107.4	0.0394	0.0402	0.0384	0.0386
2033	0.0617	0.0543	0.0476	0.0389	0.0017	0.0685	0.0605	0.0532	0.0438	83.9	97.7	90.6	115.8	103.2	0.0390	0.0398	0.0380	0.0382
2034	0.0608	0.0512	0.0505	0.0397	0.0018	0.0676	0.0573	0.0565	0.0449	82.5	94.8	89.1	112.3	100.7	0.0386	0.0394	0.0376	0.0378
2035	0.0629	0.0562	0.0562	0.0477	0.0019	0.0699	0.0627	0.0628	0.0535	88.1	101.0	95.2	119.7	107.4	0.0382	0.0390	0.0372	0.0374
2036	0.0640	0.0566	0.0592	0.0498	0.0021	0.0714	0.0634	0.0662	0.0560	89.6	102.6	96.8	121.6	109.2	0.0378	0.0386	0.0368	0.0370
2037	0.0652	0.0570	0.0623	0.0520	0.0024	0.0730	0.0641	0.0698	0.0587	91.1	104.3	98.4	123.6	111.0	0.0374	0.0381	0.0364	0.0366
2038	0.0664	0.0573	0.0655	0.0543	0.0027	0.0746	0.0648	0.0737	0.0616	92.6	105.9	100.0	125.5	112.8	0.0369	0.0377	0.0360	0.0362
2039	0.0676	0.0577	0.0689	0.0567	0.0031	0.0764	0.0656	0.0778	0.0646	94.2	107.6	101.7	127.5	114.6	0.0366	0.0373	0.0356	0.0358
2040	0.0689	0.0581	0.0725	0.0592	0.0035	0.0782	0.0665	0.0821	0.0677	95.7	109.3	103.4	129.6	116.5	0.0362	0.0369	0.0352	0.0354
2041	0.0701	0.0584	0.0763	0.0619	0.0040	0.0800	0.0674	0.0867	0.0711	97.3	111.1	105.1	131.7	118.4	0.0358	0.0365	0.0348	0.0351
2042	0.0714	0.0588	0.0803	0.0646	0.0045	0.0820	0.0684	0.0916	0.0746	98.9	112.9	106.9	133.8	120.3	0.0354	0.0361	0.0345	0.0347
2043	0.0727	0.0592	0.0845	0.0675	0.0051	0.0841	0.0695	0.0968	0.0784	100.6	114.7	108.6	135.9	122.3	0.0350	0.0357	0.0341	0.0343
2044	0.0741	0.0596	0.0889	0.0705	0.0058	0.0863	0.0706	0.1023	0.0824	102.3	116.5	110.5	138.1	124.3	0.0346	0.0354	0.0337	0.0339
2045	0.0754	0.0600	0.0935	0.0736	0.0066	0.0886	0.0719	0.1081	0.0866	104.0	118.4	112.3	140.3	126.3	0.0342	0.0350	0.0334	0.0336
2046	0.0768	0.0604	0.0984	0.0769	0.0075	0.0910	0.0733	0.1144	0.0911	105.7	120.3	114.2	142.5	128.3	0.0339	0.0346	0.0330	0.0332
2047	0.0782	0.0608	0.1036	0.0803	0.0085	0.0936	0.0748	0.1210	0.0959	107.5	122.2	116.1	144.8	130.4	0.0335	0.0342	0.0326	0.0329
2048	0.0797	0.0612	0.1090	0.0838	0.0096	0.0964	0.0764	0.1281	0.1009	109.3	124.2	118.0	147.1	132.6	0.0332	0.0339	0.0323	0.0325
2049	0.0811	0.0616	0.1146	0.0876	0.0109	0.0994	0.0783	0.1356	0.1063	111.1	126.1	120.0	149.5	134.7	0.0328	0.0335	0.0319	0.0322
2050	0.0826	0.0620	0.1206	0.0915	0.0124	0.1026	0.0803	0.1436	0.1121	112.9	128.2	122.0	151.9	136.9	0.0324	0.0331	0.0316	0.0318
Levelized Costs																		
10 years (2018-2027)	0.0541	0.0502	0.0407	0.0348	0.0049	0.0637	0.0594	0.0492	0.0428	73.3	26.4	79.2	31.2	55.2	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0560	0.0518	0.0430	0.0369	0.0038	0.0645	0.0600	0.0505	0.0439	76.9	48.6	83.1	57.6	70.4	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0617	0.0544	0.0565	0.0468	0.0039	0.0708	0.0629	0.0651	0.0547	85.1	75.7	92.0	89.7	90.8	0.0396	0.0404	0.0385	0.0388

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: OTCT

	Intrastate																			
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures									Wholesale Cross-DRIPE[7]	
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0080	0.0057	0.0057	0.0037	117.6	-	127.0	-	63.5	-	-	-	-	-	-	-	-	-	0.0032	0.0000
2019	0.0124	0.0088	0.0086	0.0062	61.1	-	66.0	-	33.0	0.0080	0.0057	0.0056	0.0040	73.6	-	79.5	-	39.7	0.0050	0.0031
2020	0.0142	0.0103	0.0109	0.0076	74.5	-	80.5	-	40.2	0.0131	0.0096	0.0100	0.0070	92.3	-	99.7	-	49.9	0.0055	0.0049
2021	0.0146	0.0106	0.0130	0.0087	12.4	-	13.3	-	6.7	0.0144	0.0104	0.0128	0.0086	16.6	-	17.9	-	8.9	0.0056	0.0050
2022	0.0131	0.0091	0.0115	0.0074	8.2	-	8.9	-	4.4	0.0144	0.0101	0.0127	0.0081	12.5	-	13.4	-	6.7	0.0050	0.0050
2023	0.0107	0.0072	0.0086	0.0054	-	7.9	-	9.3	4.7	0.0135	0.0091	0.0108	0.0068	8.2	-	8.9	-	4.4	0.0037	0.0037
2024	0.0086	0.0063	0.0063	0.0047	-	13.6	-	16.2	8.1	0.0112	0.0082	0.0082	0.0060	-	7.9	-	9.4	4.7	0.0024	0.0024
2025	0.0058	0.0043	0.0048	0.0035	-	224.5	-	266.1	133.0	0.0080	0.0059	0.0066	0.0048	-	176.1	-	208.7	104.3	0.0018	0.0018
2026	0.0031	0.0022	0.0027	0.0019	-	264.0	-	312.9	156.4	0.0057	0.0041	0.0051	0.0036	-	238.8	-	283.0	141.5	0.0013	0.0013
2027	0.0019	0.0014	0.0015	0.0010	-	258.5	-	306.4	153.2	0.0032	0.0023	0.0025	0.0017	-	278.0	-	329.5	164.7	0.0008	0.0008
2028	-	-	-	-	-	198.0	-	234.7	117.3	0.0019	0.0013	0.0016	0.0010	-	273.1	-	323.6	161.8	0.0003	0.0003
2029	-	-	-	-	-	130.2	-	154.3	77.2	-	-	-	-	-	210.5	-	249.5	124.7	0.0003	0.0003
2030	-	-	-	-	-	63.4	-	75.1	37.6	-	-	-	-	-	116.0	-	137.5	68.7	0.0003	0.0003
2031	-	-	-	-	-	29.6	-	35.1	17.5	-	-	-	-	-	67.0	-	79.4	39.7	0.0003	0.0003
2032	-	-	-	-	-	8.6	-	10.2	5.1	-	-	-	-	-	31.5	-	37.3	18.7	0.0003	0.0003
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.6	-	9.1	4.5	0.0003	0.0003
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
Levelized Costs																				
10 years (2018-2027)	0.0094	0.0067	0.0075	0.0051	28.7	77.3	30.9	91.7	58.9	0.0091	0.0065	0.0074	0.0051	21.0	71.3	22.7	84.5	50.9	0.0035	0.0028
15 years (2018-2032)	0.0064	0.0046	0.0051	0.0035	19.7	81.9	21.3	97.1	56.7	0.0064	0.0046	0.0052	0.0035	14.5	96.1	15.6	113.9	61.1	0.0025	0.0020
30 years (2018-2047)	0.0035	0.0025	0.0028	0.0019	10.9	45.0	11.7	53.4	31.2	0.0035	0.0025	0.0029	0.0020	8.0	53.1	8.6	63.0	33.7	0.0015	0.0012

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2. Uncleared capacity value includes reserve margin and uncleared load forecast effect
3. Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4. Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5. Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6. Assumes bid percentage of 50.0%
7. Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8. Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: OTCT

	Rest-of-Pool																		
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures									
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0307	0.0217	0.0206	0.0136	369.4	-	398.9	-	199.5	-	-	-	-	-	-	-	-	-
2019	0.0480	0.0337	0.0315	0.0228	193.9	-	209.4	-	104.7	0.0309	0.0218	0.0203	0.0147	233.6	-	252.3	-	126.2
2020	0.0549	0.0399	0.0400	0.0278	235.8	-	254.7	-	127.3	0.0509	0.0369	0.0370	0.0258	292.1	-	315.5	-	157.8
2021	0.0578	0.0418	0.0486	0.0329	39.3	-	42.5	-	21.2	0.0569	0.0412	0.0479	0.0324	52.7	-	56.9	-	28.5
2022	0.0517	0.0362	0.0432	0.0278	26.3	-	28.5	-	14.2	0.0570	0.0399	0.0476	0.0306	39.9	-	43.1	-	21.6
2023	0.0379	0.0258	0.0288	0.0182	-	25.3	-	30.0	15.0	0.0476	0.0325	0.0362	0.0229	26.6	-	28.7	-	14.3
2024	0.0306	0.0225	0.0213	0.0158	-	44.2	-	52.4	26.2	0.0395	0.0290	0.0275	0.0205	-	25.7	-	30.4	15.2
2025	0.0204	0.0150	0.0159	0.0116	-	725.7	-	860.0	430.0	0.0281	0.0207	0.0219	0.0160	-	569.2	-	674.5	337.2
2026	0.0107	0.0077	0.0090	0.0063	-	858.1	-	1016.9	508.4	0.0198	0.0143	0.0167	0.0117	-	776.1	-	919.7	459.8
2027	0.0065	0.0048	0.0049	0.0034	-	840.3	-	995.8	497.9	0.0110	0.0081	0.0083	0.0058	-	903.6	-	1070.8	535.4
2028	0.0000	0.0000	0.0000	0.0000	-	643.7	-	762.8	381.4	0.0065	0.0045	0.0052	0.0035	-	887.6	-	1051.8	525.9
2029	0.0000	0.0000	0.0000	0.0000	-	423.3	-	501.6	250.8	-	-	-	-	-	684.2	-	810.8	405.4
2030	-	-	-	-	-	206.1	-	244.2	122.1	-	-	-	-	-	377.1	-	446.8	223.4
2031	-	-	-	-	-	96.3	-	114.1	57.0	-	-	-	-	-	217.7	-	257.9	129.0
2032	-	-	-	-	-	27.9	-	33.1	16.5	-	-	-	-	-	102.3	-	121.3	60.6
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.8	-	29.4	14.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0354	0.0253	0.0267	0.0183	90.5	250.9	97.8	297.4	189.8	0.0343	0.0245	0.0264	0.0181	66.7	231.5	72.0	274.3	164.3
15 years (2018-2032)	0.0244	0.0174	0.0184	0.0126	62.3	265.9	67.3	315.2	183.1	0.0240	0.0172	0.0185	0.0127	45.9	312.3	49.6	370.0	197.9
30 years (2018-2047)	0.0134	0.0096	0.0101	0.0069	34.3	146.2	37.0	173.3	100.7	0.0132	0.0094	0.0102	0.0070	25.2	172.6	27.3	204.5	109.3

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: OTCT

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

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3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

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5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SWCT

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0479	0.0438	0.0319	0.0258	0.0053	0.0574	0.0530	0.0401	0.0336	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0487	0.0453	0.0318	0.0284	0.0109	0.0644	0.0607	0.0461	0.0424	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0520	0.0489	0.0376	0.0327	0.0085	0.0654	0.0620	0.0498	0.0446	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0544	0.0507	0.0455	0.0378	0.0062	0.0654	0.0614	0.0558	0.0476	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0540	0.0490	0.0446	0.0359	0.0034	0.0620	0.0566	0.0518	0.0424	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0553	0.0490	0.0417	0.0327	0.0038	0.0638	0.0569	0.0491	0.0394	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0588	0.0552	0.0411	0.0374	0.0034	0.0672	0.0632	0.0480	0.0441	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0556	0.0525	0.0432	0.0386	0.0026	0.0628	0.0595	0.0494	0.0445	65.7	53.9	70.9	63.9	67.4	0.0421	0.0429	0.0410	0.0412
2026	0.0555	0.0520	0.0468	0.0410	0.0021	0.0623	0.0585	0.0529	0.0466	71.2	74.9	76.9	88.7	82.8	0.0417	0.0426	0.0406	0.0409
2027	0.0604	0.0564	0.0448	0.0389	0.0016	0.0670	0.0627	0.0501	0.0438	76.9	89.5	83.0	106.1	94.5	0.0414	0.0423	0.0403	0.0406
2028	0.0621	0.0549	0.0489	0.0399	0.0014	0.0686	0.0608	0.0544	0.0446	82.5	94.8	89.1	112.3	100.7	0.0411	0.0420	0.0401	0.0403
2029	0.0639	0.0586	0.0480	0.0406	0.0013	0.0704	0.0646	0.0532	0.0452	88.1	101.0	95.2	119.7	107.4	0.0408	0.0417	0.0398	0.0400
2030	0.0589	0.0555	0.0506	0.0463	0.0012	0.0648	0.0613	0.0559	0.0512	83.9	97.7	90.6	115.8	103.2	0.0403	0.0412	0.0393	0.0395
2031	0.0584	0.0547	0.0459	0.0401	0.0011	0.0643	0.0603	0.0508	0.0445	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0571	0.0530	0.0469	0.0406	0.0017	0.0634	0.0591	0.0524	0.0456	88.1	101.0	95.2	119.7	107.4	0.0394	0.0402	0.0384	0.0386
2033	0.0617	0.0542	0.0476	0.0389	0.0017	0.0685	0.0604	0.0532	0.0438	83.9	97.7	90.6	115.8	103.2	0.0390	0.0398	0.0380	0.0382
2034	0.0608	0.0512	0.0505	0.0397	0.0018	0.0676	0.0572	0.0565	0.0448	82.5	94.8	89.1	112.3	100.7	0.0386	0.0394	0.0376	0.0378
2035	0.0629	0.0562	0.0563	0.0477	0.0019	0.0699	0.0627	0.0628	0.0535	88.1	101.0	95.2	119.7	107.4	0.0382	0.0390	0.0372	0.0374
2036	0.0640	0.0566	0.0592	0.0498	0.0021	0.0715	0.0634	0.0662	0.0561	89.6	102.6	96.8	121.6	109.2	0.0378	0.0386	0.0368	0.0370
2037	0.0652	0.0569	0.0623	0.0520	0.0024	0.0730	0.0641	0.0699	0.0587	91.1	104.3	98.4	123.6	111.0	0.0374	0.0381	0.0364	0.0366
2038	0.0664	0.0573	0.0656	0.0543	0.0027	0.0747	0.0648	0.0738	0.0616	92.6	105.9	100.0	125.5	112.8	0.0369	0.0377	0.0360	0.0362
2039	0.0677	0.0577	0.0690	0.0567	0.0031	0.0764	0.0656	0.0778	0.0646	94.2	107.6	101.7	127.5	114.6	0.0366	0.0373	0.0356	0.0358
2040	0.0689	0.0581	0.0726	0.0592	0.0035	0.0782	0.0665	0.0822	0.0678	95.7	109.3	103.4	129.6	116.5	0.0362	0.0369	0.0352	0.0354
2041	0.0702	0.0585	0.0764	0.0619	0.0040	0.0801	0.0674	0.0868	0.0711	97.3	111.1	105.1	131.7	118.4	0.0358	0.0365	0.0348	0.0351
2042	0.0715	0.0588	0.0804	0.0646	0.0045	0.0821	0.0684	0.0917	0.0746	98.9	112.9	106.9	133.8	120.3	0.0354	0.0361	0.0345	0.0347
2043	0.0728	0.0592	0.0846	0.0675	0.0051	0.0841	0.0695	0.0969	0.0784	100.6	114.7	108.6	135.9	122.3	0.0350	0.0357	0.0341	0.0343
2044	0.0741	0.0596	0.0890	0.0705	0.0058	0.0863	0.0707	0.1024	0.0824	102.3	116.5	110.5	138.1	124.3	0.0346	0.0354	0.0337	0.0339
2045	0.0755	0.0600	0.0937	0.0736	0.0066	0.0887	0.0719	0.1083	0.0866	104.0	118.4	112.3	140.3	126.3	0.0342	0.0350	0.0334	0.0336
2046	0.0769	0.0604	0.0986	0.0769	0.0075	0.0911	0.0733	0.1145	0.0911	105.7	120.3	114.2	142.5	128.3	0.0339	0.0346	0.0330	0.0332
2047	0.0783	0.0608	0.1037	0.0803	0.0085	0.0937	0.0748	0.1212	0.0959	107.5	122.2	116.1	144.8	130.4	0.0335	0.0342	0.0326	0.0329
2048	0.0798	0.0612	0.1091	0.0839	0.0096	0.0965	0.0765	0.1282	0.1009	109.3	124.2	118.0	147.1	132.6	0.0332	0.0339	0.0323	0.0325
2049	0.0813	0.0616	0.1148	0.0876	0.0109	0.0995	0.0783	0.1358	0.1064	111.1	126.1	120.0	149.5	134.7	0.0328	0.0335	0.0319	0.0322
2050	0.0828	0.0620	0.1208	0.0915	0.0124	0.1027	0.0803	0.1439	0.1121	112.9	128.2	122.0	151.9	136.9	0.0324	0.0331	0.0316	0.0318
Levelized Costs																		
10 years (2018-2027)	0.0541	0.0501	0.0407	0.0348	0.0049	0.0637	0.0594	0.0492	0.0428	73.3	26.4	79.2	31.2	55.2	0.0431	0.0440	0.0420	0.0423
15 years (2018-2032)	0.0560	0.0518	0.0430	0.0369	0.0038	0.0645	0.0600	0.0505	0.0439	76.9	48.6	83.1	57.6	70.4	0.0422	0.0431	0.0411	0.0414
30 years (2018-2047)	0.0618	0.0544	0.0565	0.0468	0.0039	0.0709	0.0629	0.0652	0.0547	85.1	75.7	92.0	89.7	90.8	0.0396	0.0404	0.0385	0.0388

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SWCT

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0080	0.0057	0.0057	0.0037	117.6	-	127.0	-	63.5	-	-	-	-	-	-	-	-	-	0.0032	0.0000
2019	0.0124	0.0088	0.0086	0.0062	61.1	-	66.0	-	33.0	0.0080	0.0057	0.0056	0.0040	73.6	-	79.5	-	39.7	0.0050	0.0031
2020	0.0142	0.0103	0.0109	0.0076	74.5	-	80.5	-	40.2	0.0131	0.0096	0.0100	0.0070	92.3	-	99.7	-	49.9	0.0055	0.0049
2021	0.0146	0.0106	0.0130	0.0087	12.4	-	13.3	-	6.7	0.0144	0.0104	0.0128	0.0086	16.6	-	17.9	-	8.9	0.0056	0.0050
2022	0.0131	0.0091	0.0115	0.0074	8.2	-	8.9	-	4.4	0.0144	0.0101	0.0127	0.0081	12.5	-	13.4	-	6.7	0.0050	0.0050
2023	0.0107	0.0072	0.0086	0.0054	-	7.9	-	9.3	4.7	0.0135	0.0091	0.0108	0.0068	8.2	-	8.9	-	4.4	0.0037	0.0037
2024	0.0086	0.0063	0.0063	0.0047	-	13.6	-	16.2	8.1	0.0112	0.0082	0.0082	0.0060	-	7.9	-	9.4	4.7	0.0024	0.0024
2025	0.0058	0.0043	0.0048	0.0035	-	224.5	-	266.1	133.0	0.0080	0.0059	0.0066	0.0048	-	176.1	-	208.7	104.3	0.0018	0.0018
2026	0.0031	0.0022	0.0027	0.0019	-	264.0	-	312.9	156.4	0.0057	0.0041	0.0051	0.0036	-	238.8	-	283.0	141.5	0.0013	0.0013
2027	0.0019	0.0014	0.0015	0.0010	-	258.5	-	306.4	153.2	0.0032	0.0023	0.0025	0.0017	-	278.0	-	329.5	164.7	0.0008	0.0008
2028	-	-	-	-	-	198.0	-	234.7	117.3	0.0019	0.0013	0.0016	0.0010	-	273.1	-	323.6	161.8	0.0003	0.0003
2029	-	-	-	-	-	130.2	-	154.3	77.2	-	-	-	-	-	210.5	-	249.5	124.7	0.0003	0.0003
2030	-	-	-	-	-	63.4	-	75.1	37.6	-	-	-	-	-	116.0	-	137.5	68.7	0.0003	0.0003
2031	-	-	-	-	-	29.6	-	35.1	17.5	-	-	-	-	-	67.0	-	79.4	39.7	0.0003	0.0003
2032	-	-	-	-	-	8.6	-	10.2	5.1	-	-	-	-	-	31.5	-	37.3	18.7	0.0003	0.0003
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7.6	-	9.1	4.5	0.0003	0.0003
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0003	0.0003
Levelized Costs																				
10 years (2018-2027)	0.0094	0.0067	0.0075	0.0051	28.7	77.3	30.9	91.7	58.9	0.0091	0.0065	0.0074	0.0051	21.0	71.3	22.7	84.5	50.9	0.0035	0.0028
15 years (2018-2032)	0.0064	0.0046	0.0051	0.0035	19.7	81.9	21.3	97.1	56.7	0.0064	0.0046	0.0052	0.0035	14.5	96.1	15.6	113.9	61.1	0.0025	0.0020
30 years (2018-2047)	0.0035	0.0025	0.0028	0.0019	10.9	45.0	11.7	53.4	31.2	0.0035	0.0025	0.0029	0.0020	8.0	53.1	8.6	63.0	33.7	0.0015	0.0012

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SWCT

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0307	0.0217	0.0206	0.0136	369.4	-	398.9	-	199.5	-	-	-	-	-	-	-	-	-
2019	0.0480	0.0337	0.0315	0.0228	193.9	-	209.4	-	104.7	0.0309	0.0218	0.0203	0.0147	233.6	-	252.3	-	126.2
2020	0.0549	0.0399	0.0400	0.0278	235.8	-	254.7	-	127.3	0.0509	0.0369	0.0370	0.0258	292.1	-	315.5	-	157.8
2021	0.0578	0.0418	0.0486	0.0329	39.3	-	42.5	-	21.2	0.0569	0.0412	0.0479	0.0324	52.7	-	56.9	-	28.5
2022	0.0517	0.0362	0.0432	0.0278	26.3	-	28.5	-	14.2	0.0570	0.0399	0.0476	0.0306	39.9	-	43.1	-	21.6
2023	0.0379	0.0258	0.0288	0.0182	-	25.3	-	30.0	15.0	0.0476	0.0325	0.0362	0.0229	26.6	-	28.7	-	14.3
2024	0.0306	0.0225	0.0213	0.0158	-	44.2	-	52.4	26.2	0.0395	0.0290	0.0275	0.0205	-	25.7	-	30.4	15.2
2025	0.0204	0.0150	0.0159	0.0116	-	725.7	-	860.0	430.0	0.0281	0.0207	0.0219	0.0160	-	569.2	-	674.5	337.2
2026	0.0107	0.0077	0.0090	0.0063	-	858.1	-	1016.9	508.4	0.0198	0.0143	0.0167	0.0117	-	776.1	-	919.7	459.8
2027	0.0065	0.0048	0.0049	0.0034	-	840.3	-	995.8	497.9	0.0110	0.0081	0.0083	0.0058	-	903.6	-	1070.8	535.4
2028	0.0000	0.0000	0.0000	0.0000	-	643.7	-	762.8	381.4	0.0065	0.0045	0.0052	0.0035	-	887.6	-	1051.8	525.9
2029	0.0000	0.0000	0.0000	0.0000	-	423.3	-	501.6	250.8	-	-	-	-	-	684.2	-	810.8	405.4
2030	-	-	-	-	-	206.1	-	244.2	122.1	-	-	-	-	-	377.1	-	446.8	223.4
2031	-	-	-	-	-	96.3	-	114.1	57.0	-	-	-	-	-	217.7	-	257.9	129.0
2032	-	-	-	-	-	27.9	-	33.1	16.5	-	-	-	-	-	102.3	-	121.3	60.6
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	24.8	-	29.4	14.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Levelized Costs																		
10 years (2018-2027)	0.0354	0.0253	0.0267	0.0183	90.5	250.9	97.8	297.4	189.8	0.0343	0.0245	0.0264	0.0181	66.7	231.5	72.0	274.3	164.3
15 years (2018-2032)	0.0244	0.0174	0.0184	0.0126	62.3	265.9	67.3	315.2	183.1	0.0240	0.0172	0.0185	0.0127	45.9	312.3	49.6	370.0	197.9
30 years (2018-2047)	0.0134	0.0096	0.0101	0.0069	34.3	146.2	37.0	173.3	100.7	0.0132	0.0094	0.0102	0.0070	25.2	172.6	27.3	204.5	109.3

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SWCT

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: Connecticut

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0479	0.0438	0.0318	0.0258	0.0053	0.0574	0.0530	0.0401	0.0336	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0497	0.0462	0.0324	0.0290	0.0111	0.0657	0.0619	0.0470	0.0433	102.0	0.0	110.2	0.0	55.1	0.0455	0.0465	0.0444	0.0446
2020	0.0541	0.0509	0.0391	0.0341	0.0089	0.0681	0.0645	0.0518	0.0464	76.8	0.0	83.0	0.0	41.5	0.0452	0.0462	0.0440	0.0443
2021	0.0577	0.0538	0.0482	0.0401	0.0066	0.0694	0.0652	0.0592	0.0505	63.6	0.0	68.7	0.0	34.3	0.0459	0.0468	0.0447	0.0450
2022	0.0584	0.0530	0.0482	0.0389	0.0037	0.0671	0.0613	0.0561	0.0460	62.3	0.0	67.3	0.0	33.7	0.0465	0.0475	0.0453	0.0456
2023	0.0610	0.0541	0.0460	0.0361	0.0042	0.0704	0.0629	0.0542	0.0435	64.9	23.0	70.1	27.2	48.6	0.0472	0.0482	0.0460	0.0463
2024	0.0663	0.0622	0.0462	0.0422	0.0038	0.0757	0.0712	0.0540	0.0496	69.0	40.6	74.5	48.1	61.3	0.0478	0.0488	0.0465	0.0468
2025	0.0638	0.0603	0.0495	0.0444	0.0029	0.0721	0.0683	0.0567	0.0511	75.4	61.9	81.4	73.4	77.4	0.0483	0.0493	0.0471	0.0474
2026	0.0651	0.0610	0.0548	0.0480	0.0025	0.0730	0.0685	0.0619	0.0545	83.4	87.7	90.0	104.0	97.0	0.0489	0.0499	0.0476	0.0479
2027	0.0721	0.0674	0.0535	0.0465	0.0020	0.0800	0.0749	0.0599	0.0523	91.8	107.0	99.2	126.8	113.0	0.0495	0.0505	0.0482	0.0485
2028	0.0757	0.0669	0.0596	0.0486	0.0017	0.0836	0.0741	0.0663	0.0544	100.6	115.5	108.6	136.9	122.8	0.0501	0.0512	0.0488	0.0491
2029	0.0795	0.0729	0.0596	0.0505	0.0016	0.0876	0.0804	0.0661	0.0562	109.6	125.6	118.3	148.8	133.6	0.0508	0.0519	0.0495	0.0498
2030	0.0747	0.0705	0.0642	0.0586	0.0015	0.0822	0.0777	0.0709	0.0649	106.4	124.0	114.9	146.9	130.9	0.0512	0.0522	0.0498	0.0502
2031	0.0756	0.0708	0.0594	0.0518	0.0015	0.0832	0.0781	0.0657	0.0575	106.7	122.6	115.2	145.3	130.3	0.0516	0.0527	0.0502	0.0506
2032	0.0753	0.0700	0.0618	0.0536	0.0022	0.0837	0.0780	0.0691	0.0602	116.3	133.3	125.6	157.9	141.8	0.0520	0.0531	0.0507	0.0510
2033	0.0831	0.0730	0.0640	0.0523	0.0023	0.0922	0.0814	0.0716	0.0590	112.9	131.5	122.0	155.9	138.9	0.0525	0.0536	0.0511	0.0514
2034	0.0835	0.0703	0.0694	0.0546	0.0025	0.0928	0.0786	0.0776	0.0616	113.2	130.1	122.3	154.2	138.2	0.0529	0.0541	0.0516	0.0519
2035	0.0880	0.0787	0.0788	0.0667	0.0026	0.0979	0.0878	0.0879	0.0749	123.4	141.4	133.3	167.6	150.4	0.0534	0.0546	0.0521	0.0524
2036	0.0915	0.0808	0.0845	0.0711	0.0030	0.1020	0.0905	0.0946	0.0800	128.0	146.6	138.2	173.7	155.9	0.0539	0.0551	0.0525	0.0529
2037	0.0950	0.0830	0.0907	0.0757	0.0035	0.1064	0.0934	0.1018	0.0856	132.7	151.9	143.3	180.0	161.7	0.0544	0.0556	0.0530	0.0533
2038	0.0987	0.0852	0.0974	0.0807	0.0040	0.1109	0.0963	0.1096	0.0915	137.6	157.4	148.6	186.5	167.6	0.0549	0.0561	0.0535	0.0538
2039	0.1025	0.0874	0.1045	0.0860	0.0047	0.1158	0.0995	0.1179	0.0979	142.7	163.1	154.1	193.3	173.7	0.0554	0.0566	0.0540	0.0543
2040	0.1065	0.0898	0.1122	0.0916	0.0054	0.1209	0.1028	0.1270	0.1047	148.0	169.0	159.8	200.3	180.1	0.0559	0.0571	0.0545	0.0548
2041	0.1106	0.0922	0.1204	0.0975	0.0063	0.1262	0.1063	0.1368	0.1121	153.5	175.2	165.7	207.6	186.7	0.0564	0.0576	0.0549	0.0553
2042	0.1149	0.0946	0.1292	0.1039	0.0072	0.1319	0.1100	0.1474	0.1201	159.1	181.5	171.9	215.1	193.5	0.0569	0.0581	0.0554	0.0558
2043	0.1194	0.0972	0.1387	0.1107	0.0084	0.1380	0.1140	0.1589	0.1286	165.0	188.1	178.2	223.0	200.6	0.0574	0.0586	0.0559	0.0563
2044	0.1240	0.0997	0.1489	0.1179	0.0097	0.1444	0.1182	0.1713	0.1378	171.1	195.0	184.8	231.1	207.9	0.0579	0.0592	0.0564	0.0568
2045	0.1288	0.1024	0.1598	0.1256	0.0112	0.1513	0.1227	0.1847	0.1478	177.5	202.1	191.7	239.5	215.6	0.0585	0.0597	0.0570	0.0573
2046	0.1338	0.1051	0.1715	0.1338	0.0130	0.1586	0.1276	0.1992	0.1586	184.0	209.4	198.8	248.2	223.5	0.0590	0.0602	0.0575	0.0578
2047	0.1390	0.1079	0.1840	0.1426	0.0150	0.1664	0.1328	0.2150	0.1702	190.9	217.0	206.1	257.2	231.6	0.0595	0.0608	0.0580	0.0583
2048	0.1444	0.1108	0.1975	0.1519	0.0174	0.1748	0.1385	0.2321	0.1828	197.9	224.9	213.7	266.5	240.1	0.0601	0.0613	0.0585	0.0589
2049	0.1500	0.1138	0.2120	0.1618	0.0201	0.1838	0.1446	0.2507	0.1965	205.2	233.1	221.7	276.2	248.9	0.0606	0.0619	0.0590	0.0594
2050	0.1558	0.1168	0.2275	0.1724	0.0233	0.1935	0.1513	0.2709	0.2113	212.8	241.5	229.9	286.2	258.0	0.0611	0.0624	0.0596	0.0599
Levelized Costs																		
10 years (2018-2027)	0.0589	0.0546	0.0443	0.0379	0.0053	0.0694	0.0647	0.0536	0.0466	79.8	28.7	86.2	34.0	60.1	0.0469	0.0479	0.0457	0.0460
15 years (2018-2032)	0.0638	0.0590	0.0490	0.0420	0.0043	0.0735	0.0683	0.0575	0.0500	87.6	55.4	94.6	65.6	80.1	0.0481	0.0491	0.0469	0.0472
30 years (2018-2047)	0.0795	0.0700	0.0727	0.0602	0.0050	0.0913	0.0810	0.0839	0.0704	109.7	97.5	118.4	115.6	117.0	0.0509	0.0520	0.0496	0.0499

NOTES: Avoided Costs are in Nominal Dollars

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1 Avoided cost of electric energy = (wholesale energy avoided cost + REC cost to load) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: **Connecticut**

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0080	0.0057	0.0057	0.0037	117.6	-	127.0	-	63.5	-	-	-	-	-	-	-	-	-	0.0032	0.0000
2019	0.0127	0.0090	0.0088	0.0063	62.3	-	67.3	-	33.6	0.0082	0.0058	0.0057	0.0041	75.1	-	81.1	-	40.5	0.0051	0.0032
2020	0.0147	0.0107	0.0113	0.0079	77.5	-	83.7	-	41.9	0.0137	0.0099	0.0105	0.0073	96.1	-	103.7	-	51.9	0.0057	0.0051
2021	0.0155	0.0113	0.0138	0.0092	13.1	-	14.2	-	7.1	0.0153	0.0111	0.0136	0.0091	17.6	-	19.0	-	9.5	0.0059	0.0053
2022	0.0141	0.0099	0.0125	0.0080	8.9	-	9.6	-	4.8	0.0156	0.0109	0.0137	0.0088	13.5	-	14.6	-	7.3	0.0054	0.0054
2023	0.0118	0.0080	0.0095	0.0059	-	8.7	-	10.3	5.1	0.0149	0.0100	0.0120	0.0075	9.1	-	9.8	-	4.9	0.0041	0.0041
2024	0.0097	0.0071	0.0071	0.0053	-	15.4	-	18.2	9.1	0.0126	0.0092	0.0092	0.0068	-	8.9	-	10.6	5.3	0.0027	0.0027
2025	0.0067	0.0049	0.0055	0.0040	-	257.9	-	305.6	152.8	0.0092	0.0068	0.0076	0.0055	-	202.3	-	239.7	119.8	0.0021	0.0021
2026	0.0036	0.0026	0.0032	0.0022	-	309.3	-	366.6	183.3	0.0066	0.0048	0.0060	0.0042	-	279.8	-	331.5	165.8	0.0015	0.0015
2027	0.0022	0.0016	0.0018	0.0012	-	309.0	-	366.2	183.1	0.0038	0.0028	0.0030	0.0021	-	332.2	-	393.7	196.9	0.0009	0.0009
2028	-	-	-	-	-	241.4	-	286.1	143.0	0.0023	0.0016	0.0019	0.0013	-	332.9	-	394.5	197.2	0.0003	0.0003
2029	-	-	-	-	-	161.9	-	191.9	96.0	-	-	-	-	-	261.7	-	310.2	155.1	0.0003	0.0003
2030	-	-	-	-	-	80.4	-	95.3	47.6	-	-	-	-	-	147.1	-	174.4	87.2	0.0003	0.0003
2031	-	-	-	-	-	38.3	-	45.4	22.7	-	-	-	-	-	86.6	-	102.7	51.3	0.0003	0.0003
2032	-	-	-	-	-	11.3	-	13.4	6.7	-	-	-	-	-	41.5	-	49.2	24.6	0.0003	0.0003
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	-	12.2	6.1	0.0004	0.0004
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005

Levelized Costs																				
10 years (2018-2027)	0.0102	0.0073	0.0081	0.0055	31.2	91.2	33.7	108.0	64.2	0.0100	0.0071	0.0081	0.0055	22.9	85.8	24.7	101.6	55.4	0.0038	0.0031
15 years (2018-2032)	0.0073	0.0052	0.0058	0.0040	22.5	101.0	24.3	119.7	64.5	0.0073	0.0052	0.0059	0.0040	16.5	120.9	17.8	143.3	69.6	0.0028	0.0023
30 years (2018-2047)	0.0046	0.0033	0.0036	0.0025	14.0	62.8	15.1	74.4	40.1	0.0045	0.0032	0.0037	0.0025	10.2	75.6	11.1	89.5	43.5	0.0019	0.0016

NOTES: Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: Connecticut

	Rest-of-Pool																		
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures									
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0307	0.0217	0.0206	0.0136	369.4	-	398.9	-	199.5	-	-	-	-	-	-	-	-	-
2019	0.0489	0.0344	0.0321	0.0233	197.8	-	213.6	-	106.8	0.0316	0.0222	0.0207	0.0150	238.3	-	257.4	-	128.7
2020	0.0572	0.0415	0.0416	0.0290	245.3	-	265.0	-	132.5	0.0529	0.0384	0.0385	0.0268	303.9	-	328.2	-	164.1
2021	0.0614	0.0444	0.0516	0.0349	41.8	-	45.1	-	22.5	0.0604	0.0437	0.0508	0.0343	56.0	-	60.4	-	30.2
2022	0.0560	0.0392	0.0467	0.0301	28.5	-	30.8	-	15.4	0.0617	0.0432	0.0515	0.0331	43.2	-	46.7	-	23.3
2023	0.0418	0.0285	0.0318	0.0201	-	27.9	-	33.1	16.6	0.0526	0.0358	0.0399	0.0253	29.3	-	31.7	-	15.8
2024	0.0345	0.0253	0.0240	0.0178	-	49.8	-	59.0	29.5	0.0445	0.0327	0.0310	0.0230	-	28.9	-	34.3	17.1
2025	0.0234	0.0173	0.0183	0.0133	-	833.6	-	987.9	494.0	0.0322	0.0238	0.0252	0.0183	-	653.8	-	774.8	387.4
2026	0.0125	0.0090	0.0106	0.0074	-	1005.4	-	1191.4	595.7	0.0232	0.0167	0.0196	0.0137	-	909.3	-	1077.6	538.8
2027	0.0078	0.0057	0.0059	0.0041	-	1004.3	-	1190.1	595.1	0.0132	0.0097	0.0099	0.0069	-	1079.8	-	1279.7	639.8
2028	0.0000	0.0000	0.0000	0.0000	-	784.7	-	929.9	464.9	0.0079	0.0055	0.0063	0.0042	-	1082.0	-	1282.2	641.1
2029	0.0000	0.0000	0.0000	0.0000	-	526.3	-	623.7	311.9	-	-	-	-	-	850.7	-	1008.1	504.1
2030	-	-	-	-	-	261.3	-	309.7	154.9	-	-	-	-	-	478.2	-	566.7	283.3
2031	-	-	-	-	-	124.5	-	147.6	73.8	-	-	-	-	-	281.6	-	333.7	166.8
2032	-	-	-	-	-	36.8	-	43.6	21.8	-	-	-	-	-	135.0	-	160.0	80.0
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33.4	-	39.6	19.8
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0386	0.0275	0.0291	0.0199	98.6	295.8	106.5	350.6	206.7	0.0373	0.0267	0.0287	0.0197	72.6	278.4	78.4	329.9	179.0
15 years (2018-2032)	0.0278	0.0198	0.0210	0.0143	71.0	327.9	76.7	388.5	208.5	0.0273	0.0195	0.0211	0.0144	52.3	392.6	56.5	465.3	225.4
30 years (2018-2047)	0.0173	0.0123	0.0130	0.0089	44.1	203.9	47.7	241.6	129.6	0.0170	0.0121	0.0131	0.0090	32.5	245.4	35.1	290.8	140.8

NOTES: Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: Connecticut

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	95.9	2.2	12.9	7.6	2.7	12.9	7.8
2020	97.8	1.0	4.8	2.9	1.2	4.8	3.0
2021	99.8	0.3	8.2	4.3	0.4	8.2	4.3
2022	101.7	0.2	8.6	4.4	0.3	8.6	4.5
2023	103.8	0.1	6.5	3.3	0.2	8.9	4.6
2024	105.9	-	5.2	2.6	0.1	7.0	3.6
2025	108.0	-	9.5	4.8	-	10.3	5.2
2026	110.1	-	8.9	4.5	-	10.6	5.3
2027	112.3	-	7.7	3.8	-	10.0	5.0
2028	114.6	-	8.0	4.0	-	11.0	5.5
2029	116.9	-	5.3	2.7	-	8.6	4.3
2030	119.2	-	2.0	1.0	-	3.6	1.8
2031	121.6	-	1.3	0.7	-	2.9	1.5
2032	124.0	-	0.4	0.2	-	1.4	0.7
2033	126.5	-	-	-	-	0.2	0.1
2034	129.0	-	-	-	-	-	-
2035	131.6	-	-	-	-	-	-
2036	134.3	-	-	-	-	-	-
2037	136.9	-	-	-	-	-	-
2038	139.7	-	-	-	-	-	-
2039	142.5	-	-	-	-	-	-
2040	145.3	-	-	-	-	-	-
2041	148.2	-	-	-	-	-	-
2042	151.2	-	-	-	-	-	-
2043	154.2	-	-	-	-	-	-
2044	157.3	-	-	-	-	-	-
2045	160.4	-	-	-	-	-	-
2046	163.7	-	-	-	-	-	-
2047	166.9	-	-	-	-	-	-
2048	170.3	-	-	-	-	-	-
2049	173.7	-	-	-	-	-	-
2050	177.1	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	102.4	1.0	9.1	5.0	0.5	8.0	4.3
15 years (2018-2032)	107.1	0.7	7.5	4.1	0.4	7.3	3.9
30 years (2018-2047)	121.1	0.5	4.7	2.6	0.2	4.6	2.4

NOTES: Avoided Costs are in Nominal Dollars

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5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: OTCT

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m *(1-%Bid)	o	p	q	r
2018	0.0479	0.0438	0.0318	0.0258	0.0053	0.0574	0.0531	0.0401	0.0336	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0497	0.0462	0.0324	0.0290	0.0111	0.0657	0.0619	0.0470	0.0433	102.0	0.0	110.2	0.0	55.1	0.0455	0.0465	0.0444	0.0446
2020	0.0541	0.0509	0.0391	0.0341	0.0089	0.0681	0.0645	0.0518	0.0464	76.8	0.0	83.0	0.0	41.5	0.0452	0.0462	0.0440	0.0443
2021	0.0577	0.0538	0.0482	0.0401	0.0066	0.0694	0.0653	0.0592	0.0505	63.6	0.0	68.7	0.0	34.3	0.0459	0.0468	0.0447	0.0450
2022	0.0584	0.0531	0.0482	0.0389	0.0037	0.0670	0.0613	0.0561	0.0460	62.3	0.0	67.3	0.0	33.7	0.0465	0.0475	0.0453	0.0456
2023	0.0610	0.0541	0.0460	0.0361	0.0042	0.0704	0.0629	0.0542	0.0435	64.9	23.0	70.1	27.2	48.6	0.0472	0.0482	0.0460	0.0463
2024	0.0662	0.0622	0.0462	0.0422	0.0038	0.0757	0.0713	0.0540	0.0496	69.0	40.6	74.5	48.1	61.3	0.0478	0.0488	0.0465	0.0468
2025	0.0638	0.0603	0.0495	0.0443	0.0029	0.0721	0.0684	0.0567	0.0511	75.4	61.9	81.4	73.4	77.4	0.0483	0.0493	0.0471	0.0474
2026	0.0651	0.0610	0.0548	0.0480	0.0025	0.0730	0.0686	0.0619	0.0545	83.4	87.7	90.0	104.0	97.0	0.0489	0.0499	0.0476	0.0479
2027	0.0721	0.0675	0.0534	0.0465	0.0020	0.0800	0.0750	0.0598	0.0523	91.8	107.0	99.2	126.8	113.0	0.0495	0.0505	0.0482	0.0485
2028	0.0757	0.0669	0.0596	0.0486	0.0017	0.0836	0.0741	0.0662	0.0544	100.6	115.5	108.6	136.9	122.8	0.0501	0.0512	0.0488	0.0491
2029	0.0795	0.0729	0.0596	0.0505	0.0016	0.0875	0.0804	0.0661	0.0562	109.6	125.6	118.3	148.8	133.6	0.0508	0.0519	0.0495	0.0498
2030	0.0747	0.0705	0.0641	0.0586	0.0015	0.0822	0.0777	0.0709	0.0649	106.4	124.0	114.9	146.9	130.9	0.0512	0.0522	0.0498	0.0502
2031	0.0756	0.0709	0.0594	0.0518	0.0015	0.0832	0.0781	0.0657	0.0575	106.7	122.6	115.2	145.3	130.3	0.0516	0.0527	0.0502	0.0506
2032	0.0753	0.0700	0.0618	0.0536	0.0022	0.0837	0.0780	0.0691	0.0602	116.3	133.3	125.6	157.9	141.8	0.0520	0.0531	0.0507	0.0510
2033	0.0831	0.0731	0.0640	0.0523	0.0023	0.0922	0.0814	0.0716	0.0590	112.9	131.5	122.0	155.9	138.9	0.0525	0.0536	0.0511	0.0514
2034	0.0835	0.0703	0.0694	0.0546	0.0025	0.0928	0.0786	0.0776	0.0616	113.2	130.1	122.3	154.2	138.2	0.0529	0.0541	0.0516	0.0519
2035	0.0880	0.0787	0.0788	0.0667	0.0026	0.0979	0.0878	0.0879	0.0749	123.4	141.4	133.3	167.6	150.4	0.0534	0.0546	0.0521	0.0524
2036	0.0914	0.0808	0.0845	0.0711	0.0030	0.1020	0.0905	0.0945	0.0800	128.0	146.6	138.2	173.7	155.9	0.0539	0.0551	0.0525	0.0529
2037	0.0950	0.0830	0.0907	0.0757	0.0035	0.1063	0.0934	0.1017	0.0856	132.7	151.9	143.3	180.0	161.7	0.0544	0.0556	0.0530	0.0533
2038	0.0987	0.0852	0.0974	0.0807	0.0040	0.1109	0.0964	0.1095	0.0915	137.6	157.4	148.6	186.5	167.6	0.0549	0.0561	0.0535	0.0538
2039	0.1025	0.0874	0.1045	0.0860	0.0047	0.1157	0.0995	0.1179	0.0979	142.7	163.1	154.1	193.3	173.7	0.0554	0.0566	0.0540	0.0543
2040	0.1065	0.0898	0.1121	0.0916	0.0054	0.1208	0.1028	0.1270	0.1047	148.0	169.0	159.8	200.3	180.1	0.0559	0.0571	0.0545	0.0548
2041	0.1106	0.0922	0.1203	0.0975	0.0063	0.1262	0.1063	0.1367	0.1121	153.5	175.2	165.7	207.6	186.7	0.0564	0.0576	0.0549	0.0553
2042	0.1149	0.0946	0.1292	0.1039	0.0072	0.1319	0.1100	0.1473	0.1201	159.1	181.5	171.9	215.1	193.5	0.0569	0.0581	0.0554	0.0558
2043	0.1193	0.0971	0.1386	0.1107	0.0084	0.1379	0.1140	0.1588	0.1286	165.0	188.1	178.2	223.0	200.6	0.0574	0.0586	0.0559	0.0563
2044	0.1239	0.0997	0.1488	0.1179	0.0097	0.1443	0.1182	0.1712	0.1378	171.1	195.0	184.8	231.1	207.9	0.0579	0.0592	0.0564	0.0568
2045	0.1288	0.1024	0.1597	0.1256	0.0112	0.1512	0.1227	0.1846	0.1478	177.5	202.1	191.7	239.5	215.6	0.0585	0.0597	0.0570	0.0573
2046	0.1337	0.1051	0.1714	0.1338	0.0130	0.1585	0.1276	0.1991	0.1586	184.0	209.4	198.8	248.2	223.5	0.0590	0.0602	0.0575	0.0578
2047	0.1389	0.1079	0.1839	0.1426	0.0150	0.1663	0.1328	0.2149	0.1702	190.9	217.0	206.1	257.2	231.6	0.0595	0.0608	0.0580	0.0583
2048	0.1443	0.1108	0.1974	0.1519	0.0174	0.1747	0.1384	0.2320	0.1828	197.9	224.9	213.7	266.5	240.1	0.0601	0.0613	0.0585	0.0589
2049	0.1499	0.1137	0.2118	0.1618	0.0201	0.1837	0.1446	0.2505	0.1965	205.2	233.1	221.7	276.2	248.9	0.0606	0.0619	0.0590	0.0594
2050	0.1557	0.1168	0.2273	0.1724	0.0233	0.1933	0.1513	0.2707	0.2113	212.8	241.5	229.9	286.2	258.0	0.0611	0.0624	0.0596	0.0599
Levelized Costs																		
10 years (2018-2027)	0.0589	0.0546	0.0443	0.0379	0.0053	0.0694	0.0647	0.0536	0.0466	79.8	28.7	86.2	34.0	60.1	0.0469	0.0479	0.0457	0.0460
15 years (2018-2032)	0.0638	0.0590	0.0490	0.0420	0.0043	0.0735	0.0683	0.0575	0.0500	87.6	55.4	94.6	65.6	80.1	0.0481	0.0491	0.0469	0.0472
30 years (2018-2047)	0.0795	0.0701	0.0727	0.0602	0.0050	0.0912	0.0810	0.0839	0.0704	109.7	97.5	118.4	115.6	117.0	0.0509	0.0520	0.0496	0.0499

NOTES: Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: OTCT

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures										
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0080	0.0057	0.0057	0.0037	117.6	-	127.0	-	63.5	-	-	-	-	-	-	-	-	-	0.0032	0.0000
2019	0.0127	0.0090	0.0088	0.0063	62.3	-	67.3	-	33.6	0.0082	0.0058	0.0057	0.0041	75.1	-	81.1	-	40.5	0.0051	0.0032
2020	0.0147	0.0107	0.0113	0.0079	77.5	-	83.7	-	41.9	0.0137	0.0099	0.0105	0.0073	96.1	-	103.7	-	51.9	0.0057	0.0051
2021	0.0155	0.0113	0.0138	0.0092	13.1	-	14.2	-	7.1	0.0153	0.0111	0.0136	0.0091	17.6	-	19.0	-	9.5	0.0059	0.0053
2022	0.0141	0.0099	0.0125	0.0080	8.9	-	9.6	-	4.8	0.0156	0.0109	0.0137	0.0088	13.5	-	14.6	-	7.3	0.0054	0.0054
2023	0.0118	0.0080	0.0095	0.0059	-	8.7	-	10.3	5.1	0.0149	0.0100	0.0120	0.0075	9.1	-	9.8	-	4.9	0.0041	0.0041
2024	0.0097	0.0071	0.0071	0.0053	-	15.4	-	18.2	9.1	0.0126	0.0092	0.0092	0.0068	-	8.9	-	10.6	5.3	0.0027	0.0027
2025	0.0067	0.0049	0.0055	0.0040	-	257.9	-	305.6	152.8	0.0092	0.0068	0.0076	0.0055	-	202.3	-	239.7	119.8	0.0021	0.0021
2026	0.0036	0.0026	0.0032	0.0022	-	309.3	-	366.6	183.3	0.0066	0.0048	0.0060	0.0042	-	279.8	-	331.5	165.8	0.0015	0.0015
2027	0.0022	0.0016	0.0018	0.0012	-	309.0	-	366.2	183.1	0.0038	0.0028	0.0030	0.0021	-	332.2	-	393.7	196.9	0.0009	0.0009
2028	-	-	-	-	-	241.4	-	286.1	143.0	0.0023	0.0016	0.0019	0.0013	-	332.9	-	394.5	197.2	0.0003	0.0003
2029	-	-	-	-	-	161.9	-	191.9	96.0	-	-	-	-	-	261.7	-	310.2	155.1	0.0003	0.0003
2030	-	-	-	-	-	80.4	-	95.3	47.6	-	-	-	-	-	147.1	-	174.4	87.2	0.0003	0.0003
2031	-	-	-	-	-	38.3	-	45.4	22.7	-	-	-	-	-	86.6	-	102.7	51.3	0.0003	0.0003
2032	-	-	-	-	-	11.3	-	13.4	6.7	-	-	-	-	-	41.5	-	49.2	24.6	0.0003	0.0003
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	-	12.2	6.1	0.0004	0.0004
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
Levelized Costs																				
10 years (2018-2027)	0.0102	0.0073	0.0081	0.0055	31.2	91.2	33.7	108.0	64.2	0.0100	0.0071	0.0081	0.0055	22.9	85.8	24.7	101.6	55.4	0.0038	0.0031
15 years (2018-2032)	0.0073	0.0052	0.0058	0.0040	22.5	101.0	24.3	119.7	64.5	0.0073	0.0052	0.0059	0.0040	16.5	120.9	17.8	143.3	69.6	0.0028	0.0023
30 years (2018-2047)	0.0046	0.0033	0.0036	0.0025	14.0	62.8	15.1	74.4	40.1	0.0045	0.0032	0.0037	0.0025	10.2	75.6	11.1	89.5	43.5	0.0019	0.0016

NOTES: Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: OTCT

	Rest-of-Pool																		
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures									
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0307	0.0217	0.0206	0.0136	369.4	-	398.9	-	199.5	-	-	-	-	-	-	-	-	-
2019	0.0489	0.0344	0.0321	0.0233	197.8	-	213.6	-	106.8	0.0316	0.0222	0.0207	0.0150	238.3	-	257.4	-	128.7
2020	0.0572	0.0415	0.0416	0.0290	245.3	-	265.0	-	132.5	0.0529	0.0384	0.0385	0.0268	303.9	-	328.2	-	164.1
2021	0.0614	0.0444	0.0516	0.0349	41.8	-	45.1	-	22.5	0.0604	0.0437	0.0508	0.0343	56.0	-	60.4	-	30.2
2022	0.0560	0.0392	0.0467	0.0301	28.5	-	30.8	-	15.4	0.0617	0.0432	0.0515	0.0331	43.2	-	46.7	-	23.3
2023	0.0418	0.0285	0.0318	0.0201	-	27.9	-	33.1	16.6	0.0526	0.0358	0.0399	0.0253	29.3	-	31.7	-	15.8
2024	0.0345	0.0253	0.0240	0.0178	-	49.8	-	59.0	29.5	0.0445	0.0327	0.0310	0.0230	-	28.9	-	34.3	17.1
2025	0.0234	0.0173	0.0183	0.0133	-	833.6	-	987.9	494.0	0.0322	0.0238	0.0252	0.0183	-	653.8	-	774.8	387.4
2026	0.0125	0.0090	0.0106	0.0074	-	1005.4	-	1191.4	595.7	0.0232	0.0167	0.0196	0.0137	-	909.3	-	1077.6	538.8
2027	0.0078	0.0057	0.0059	0.0041	-	1004.3	-	1190.1	595.1	0.0132	0.0097	0.0099	0.0069	-	1079.8	-	1279.7	639.8
2028	0.0000	0.0000	0.0000	0.0000	-	784.7	-	929.9	464.9	0.0079	0.0055	0.0063	0.0042	-	1082.0	-	1282.2	641.1
2029	0.0000	0.0000	0.0000	0.0000	-	526.3	-	623.7	311.9	-	-	-	-	-	850.7	-	1008.1	504.1
2030	-	-	-	-	-	261.3	-	309.7	154.9	-	-	-	-	-	478.2	-	566.7	283.3
2031	-	-	-	-	-	124.5	-	147.6	73.8	-	-	-	-	-	281.6	-	333.7	166.8
2032	-	-	-	-	-	36.8	-	43.6	21.8	-	-	-	-	-	135.0	-	160.0	80.0
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33.4	-	39.6	19.8
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0386	0.0275	0.0291	0.0199	98.6	295.8	106.5	350.6	206.7	0.0373	0.0267	0.0287	0.0197	72.6	278.4	78.4	329.9	179.0
15 years (2018-2032)	0.0278	0.0198	0.0210	0.0143	71.0	327.9	76.7	388.5	208.5	0.0273	0.0195	0.0211	0.0144	52.3	392.6	56.5	465.3	225.4
30 years (2018-2047)	0.0173	0.0123	0.0130	0.0089	44.1	203.9	47.7	241.6	129.6	0.0170	0.0121	0.0131	0.0090	32.5	245.4	35.1	290.8	140.8

NOTES:

Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: OTCT

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	95.9	2.2	12.9	7.6	2.7	12.9	7.8
2020	97.8	1.0	4.8	2.9	1.2	4.8	3.0
2021	99.8	0.3	8.2	4.3	0.4	8.2	4.3
2022	101.7	0.2	8.6	4.4	0.3	8.6	4.5
2023	103.8	0.1	6.5	3.3	0.2	8.9	4.6
2024	105.9	-	5.2	2.6	0.1	7.0	3.6
2025	108.0	-	9.5	4.8	-	10.3	5.2
2026	110.1	-	8.9	4.5	-	10.6	5.3
2027	112.3	-	7.7	3.8	-	10.0	5.0
2028	114.6	-	8.0	4.0	-	11.0	5.5
2029	116.9	-	5.3	2.7	-	8.6	4.3
2030	119.2	-	2.0	1.0	-	3.6	1.8
2031	121.6	-	1.3	0.7	-	2.9	1.5
2032	124.0	-	0.4	0.2	-	1.4	0.7
2033	126.5	-	-	-	-	0.2	0.1
2034	129.0	-	-	-	-	-	-
2035	131.6	-	-	-	-	-	-
2036	134.3	-	-	-	-	-	-
2037	136.9	-	-	-	-	-	-
2038	139.7	-	-	-	-	-	-
2039	142.5	-	-	-	-	-	-
2040	145.3	-	-	-	-	-	-
2041	148.2	-	-	-	-	-	-
2042	151.2	-	-	-	-	-	-
2043	154.2	-	-	-	-	-	-
2044	157.3	-	-	-	-	-	-
2045	160.4	-	-	-	-	-	-
2046	163.7	-	-	-	-	-	-
2047	166.9	-	-	-	-	-	-
2048	170.3	-	-	-	-	-	-
2049	173.7	-	-	-	-	-	-
2050	177.1	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	102.4	1.0	9.1	5.0	0.5	8.0	4.3
15 years (2018-2032)	107.1	0.7	7.5	4.1	0.4	7.3	3.9
30 years (2018-2047)	121.1	0.5	4.7	2.6	0.2	4.6	2.4

NOTES: Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: SWCT

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0479	0.0438	0.0319	0.0258	0.0053	0.0574	0.0530	0.0401	0.0336	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0497	0.0462	0.0324	0.0290	0.0111	0.0657	0.0619	0.0470	0.0433	102.0	0.0	110.2	0.0	55.1	0.0455	0.0465	0.0444	0.0446
2020	0.0541	0.0508	0.0391	0.0341	0.0089	0.0681	0.0645	0.0518	0.0464	76.8	0.0	83.0	0.0	41.5	0.0452	0.0462	0.0440	0.0443
2021	0.0577	0.0538	0.0482	0.0401	0.0066	0.0694	0.0652	0.0592	0.0505	63.6	0.0	68.7	0.0	34.3	0.0459	0.0468	0.0447	0.0450
2022	0.0584	0.0530	0.0482	0.0389	0.0037	0.0671	0.0613	0.0561	0.0459	62.3	0.0	67.3	0.0	33.7	0.0465	0.0475	0.0453	0.0456
2023	0.0610	0.0541	0.0460	0.0361	0.0042	0.0704	0.0629	0.0542	0.0435	64.9	23.0	70.1	27.2	48.6	0.0472	0.0482	0.0460	0.0463
2024	0.0663	0.0621	0.0462	0.0422	0.0038	0.0757	0.0712	0.0541	0.0496	69.0	40.6	74.5	48.1	61.3	0.0478	0.0488	0.0465	0.0468
2025	0.0638	0.0603	0.0496	0.0444	0.0029	0.0721	0.0683	0.0567	0.0511	75.4	61.9	81.4	73.4	77.4	0.0483	0.0493	0.0471	0.0474
2026	0.0651	0.0610	0.0549	0.0480	0.0025	0.0730	0.0685	0.0619	0.0545	83.4	87.7	90.0	104.0	97.0	0.0489	0.0499	0.0476	0.0479
2027	0.0721	0.0674	0.0535	0.0465	0.0020	0.0800	0.0749	0.0599	0.0523	91.8	107.0	99.2	126.8	113.0	0.0495	0.0505	0.0482	0.0485
2028	0.0757	0.0669	0.0596	0.0486	0.0017	0.0836	0.0741	0.0663	0.0544	100.6	115.5	108.6	136.9	122.8	0.0501	0.0512	0.0488	0.0491
2029	0.0795	0.0728	0.0596	0.0505	0.0016	0.0876	0.0804	0.0661	0.0562	109.6	125.6	118.3	148.8	133.6	0.0508	0.0519	0.0495	0.0498
2030	0.0747	0.0704	0.0642	0.0587	0.0015	0.0822	0.0777	0.0709	0.0650	106.4	124.0	114.9	146.9	130.9	0.0512	0.0522	0.0498	0.0502
2031	0.0756	0.0708	0.0594	0.0518	0.0015	0.0832	0.0780	0.0657	0.0575	106.7	122.6	115.2	145.3	130.3	0.0516	0.0527	0.0502	0.0506
2032	0.0753	0.0700	0.0618	0.0536	0.0022	0.0837	0.0779	0.0691	0.0602	116.3	133.3	125.6	157.9	141.8	0.0520	0.0531	0.0507	0.0510
2033	0.0831	0.0730	0.0640	0.0523	0.0023	0.0922	0.0813	0.0716	0.0590	112.9	131.5	122.0	155.9	138.9	0.0525	0.0536	0.0511	0.0514
2034	0.0835	0.0703	0.0694	0.0545	0.0025	0.0928	0.0785	0.0776	0.0616	113.2	130.1	122.3	154.2	138.2	0.0529	0.0541	0.0516	0.0519
2035	0.0881	0.0787	0.0788	0.0667	0.0026	0.0979	0.0878	0.0879	0.0749	123.4	141.4	133.3	167.6	150.4	0.0534	0.0546	0.0521	0.0524
2036	0.0915	0.0808	0.0846	0.0711	0.0030	0.1021	0.0905	0.0946	0.0801	128.0	146.6	138.2	173.7	155.9	0.0539	0.0551	0.0525	0.0529
2037	0.0950	0.0829	0.0908	0.0757	0.0035	0.1064	0.0934	0.1018	0.0856	132.7	151.9	143.3	180.0	161.7	0.0544	0.0556	0.0530	0.0533
2038	0.0987	0.0852	0.0974	0.0807	0.0040	0.1110	0.0963	0.1096	0.0915	137.6	157.4	148.6	186.5	167.6	0.0549	0.0561	0.0535	0.0538
2039	0.1026	0.0874	0.1046	0.0860	0.0047	0.1158	0.0995	0.1180	0.0979	142.7	163.1	154.1	193.3	173.7	0.0554	0.0566	0.0540	0.0543
2040	0.1065	0.0898	0.1122	0.0916	0.0054	0.1209	0.1028	0.1271	0.1047	148.0	169.0	159.8	200.3	180.1	0.0559	0.0571	0.0545	0.0548
2041	0.1107	0.0922	0.1205	0.0976	0.0063	0.1263	0.1063	0.1369	0.1121	153.5	175.2	165.7	207.6	186.7	0.0564	0.0576	0.0549	0.0553
2042	0.1150	0.0946	0.1293	0.1039	0.0072	0.1320	0.1100	0.1475	0.1201	159.1	181.5	171.9	215.1	193.5	0.0569	0.0581	0.0554	0.0558
2043	0.1194	0.0972	0.1388	0.1107	0.0084	0.1381	0.1140	0.1589	0.1286	165.0	188.1	178.2	223.0	200.6	0.0574	0.0586	0.0559	0.0563
2044	0.1241	0.0998	0.1490	0.1179	0.0097	0.1445	0.1182	0.1714	0.1379	171.1	195.0	184.8	231.1	207.9	0.0579	0.0592	0.0564	0.0568
2045	0.1289	0.1024	0.1599	0.1256	0.0112	0.1513	0.1228	0.1848	0.1478	177.5	202.1	191.7	239.5	215.6	0.0585	0.0597	0.0570	0.0573
2046	0.1339	0.1052	0.1716	0.1338	0.0130	0.1587	0.1276	0.1994	0.1586	184.0	209.4	198.8	248.2	223.5	0.0590	0.0602	0.0575	0.0578
2047	0.1391	0.1080	0.1842	0.1426	0.0150	0.1665	0.1329	0.2152	0.1702	190.9	217.0	206.1	257.2	231.6	0.0595	0.0608	0.0580	0.0583
2048	0.1445	0.1109	0.1977	0.1519	0.0174	0.1749	0.1385	0.2323	0.1828	197.9	224.9	213.7	266.5	240.1	0.0601	0.0613	0.0585	0.0589
2049	0.1501	0.1138	0.2122	0.1618	0.0201	0.1839	0.1447	0.2509	0.1965	205.2	233.1	221.7	276.2	248.9	0.0606	0.0619	0.0590	0.0594
2050	0.1560	0.1169	0.2277	0.1724	0.0233	0.1936	0.1514	0.2711	0.2113	212.8	241.5	229.9	286.2	258.0	0.0611	0.0624	0.0596	0.0599

Levelized Costs																		
10 years (2018-2027)	0.0589	0.0546	0.0443	0.0379	0.0053	0.0694	0.0647	0.0536	0.0466	79.8	28.7	86.2	34.0	60.1	0.0469	0.0479	0.0457	0.0460
15 years (2018-2032)	0.0638	0.0590	0.0490	0.0420	0.0043	0.0735	0.0683	0.0575	0.0500	87.6	55.4	94.6	65.6	80.1	0.0481	0.0491	0.0469	0.0472
30 years (2018-2047)	0.0796	0.0700	0.0728	0.0602	0.0050	0.0913	0.0810	0.0839	0.0704	109.7	97.5	118.4	115.6	117.0	0.0509	0.0520	0.0496	0.0499

NOTES:

Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: SWCT

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0080	0.0057	0.0057	0.0037	117.6	-	127.0	-	63.5	-	-	-	-	-	-	-	-	-	0.0032	0.0000
2019	0.0127	0.0090	0.0088	0.0063	62.3	-	67.3	-	33.6	0.0082	0.0058	0.0057	0.0041	75.1	-	81.1	-	40.5	0.0051	0.0032
2020	0.0147	0.0107	0.0113	0.0079	77.5	-	83.7	-	41.9	0.0137	0.0099	0.0105	0.0073	96.1	-	103.7	-	51.9	0.0057	0.0051
2021	0.0155	0.0113	0.0138	0.0092	13.1	-	14.2	-	7.1	0.0153	0.0111	0.0136	0.0091	17.6	-	19.0	-	9.5	0.0059	0.0053
2022	0.0141	0.0099	0.0125	0.0080	8.9	-	9.6	-	4.8	0.0156	0.0109	0.0137	0.0088	13.5	-	14.6	-	7.3	0.0054	0.0054
2023	0.0118	0.0080	0.0095	0.0059	-	8.7	-	10.3	5.1	0.0149	0.0100	0.0120	0.0075	9.1	-	9.8	-	4.9	0.0041	0.0041
2024	0.0097	0.0071	0.0071	0.0053	-	15.4	-	18.2	9.1	0.0126	0.0092	0.0092	0.0068	-	8.9	-	10.6	5.3	0.0027	0.0027
2025	0.0067	0.0049	0.0055	0.0040	-	257.9	-	305.6	152.8	0.0092	0.0068	0.0076	0.0055	-	202.3	-	239.7	119.8	0.0021	0.0021
2026	0.0036	0.0026	0.0032	0.0022	-	309.3	-	366.6	183.3	0.0066	0.0048	0.0060	0.0042	-	279.8	-	331.5	165.8	0.0015	0.0015
2027	0.0022	0.0016	0.0018	0.0012	-	309.0	-	366.2	183.1	0.0038	0.0028	0.0030	0.0021	-	332.2	-	393.7	196.9	0.0009	0.0009
2028	-	-	-	-	-	241.4	-	286.1	143.0	0.0023	0.0016	0.0019	0.0013	-	332.9	-	394.5	197.2	0.0003	0.0003
2029	-	-	-	-	-	161.9	-	191.9	96.0	-	-	-	-	-	261.7	-	310.2	155.1	0.0003	0.0003
2030	-	-	-	-	-	80.4	-	95.3	47.6	-	-	-	-	-	147.1	-	174.4	87.2	0.0003	0.0003
2031	-	-	-	-	-	38.3	-	45.4	22.7	-	-	-	-	-	86.6	-	102.7	51.3	0.0003	0.0003
2032	-	-	-	-	-	11.3	-	13.4	6.7	-	-	-	-	-	41.5	-	49.2	24.6	0.0003	0.0003
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10.3	-	12.2	6.1	0.0004	0.0004
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0004	0.0004
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0005	0.0005
Levelized Costs																				
10 years (2018-2027)	0.0102	0.0073	0.0081	0.0055	31.2	91.2	33.7	108.0	64.2	0.0100	0.0071	0.0081	0.0055	22.9	85.8	24.7	101.6	55.4	0.0038	0.0031
15 years (2018-2032)	0.0073	0.0052	0.0058	0.0040	22.5	101.0	24.3	119.7	64.5	0.0073	0.0052	0.0059	0.0040	16.5	120.9	17.8	143.3	69.6	0.0028	0.0023
30 years (2018-2047)	0.0046	0.0033	0.0036	0.0025	14.0	62.8	15.1	74.4	40.1	0.0045	0.0032	0.0037	0.0025	10.2	75.6	11.1	89.5	43.5	0.0019	0.0016

NOTES: Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: SWCT

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0307	0.0217	0.0206	0.0136	369.4	-	398.9	-	199.5	-	-	-	-	-	-	-	-	-
2019	0.0489	0.0344	0.0321	0.0233	197.8	-	213.6	-	106.8	0.0316	0.0222	0.0207	0.0150	238.3	-	257.4	-	128.7
2020	0.0572	0.0415	0.0416	0.0290	245.3	-	265.0	-	132.5	0.0529	0.0384	0.0385	0.0268	303.9	-	328.2	-	164.1
2021	0.0614	0.0444	0.0516	0.0349	41.8	-	45.1	-	22.5	0.0604	0.0437	0.0508	0.0343	56.0	-	60.4	-	30.2
2022	0.0560	0.0392	0.0467	0.0301	28.5	-	30.8	-	15.4	0.0617	0.0432	0.0515	0.0331	43.2	-	46.7	-	23.3
2023	0.0418	0.0285	0.0318	0.0201	-	27.9	-	33.1	16.6	0.0526	0.0358	0.0399	0.0253	29.3	-	31.7	-	15.8
2024	0.0345	0.0253	0.0240	0.0178	-	49.8	-	59.0	29.5	0.0445	0.0327	0.0310	0.0230	-	28.9	-	34.3	17.1
2025	0.0234	0.0173	0.0183	0.0133	-	833.6	-	987.9	494.0	0.0322	0.0238	0.0252	0.0183	-	653.8	-	774.8	387.4
2026	0.0125	0.0090	0.0106	0.0074	-	1005.4	-	1191.4	595.7	0.0232	0.0167	0.0196	0.0137	-	909.3	-	1077.6	538.8
2027	0.0078	0.0057	0.0059	0.0041	-	1004.3	-	1190.1	595.1	0.0132	0.0097	0.0099	0.0069	-	1079.8	-	1279.7	639.8
2028	0.0000	0.0000	0.0000	0.0000	-	784.7	-	929.9	464.9	0.0079	0.0055	0.0063	0.0042	-	1082.0	-	1282.2	641.1
2029	0.0000	0.0000	0.0000	0.0000	-	526.3	-	623.7	311.9	-	-	-	-	-	850.7	-	1008.1	504.1
2030	-	-	-	-	-	261.3	-	309.7	154.9	-	-	-	-	-	478.2	-	566.7	283.3
2031	-	-	-	-	-	124.5	-	147.6	73.8	-	-	-	-	-	281.6	-	333.7	166.8
2032	-	-	-	-	-	36.8	-	43.6	21.8	-	-	-	-	-	135.0	-	160.0	80.0
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	33.4	-	39.6	19.8
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0386	0.0275	0.0291	0.0199	98.6	295.8	106.5	350.6	206.7	0.0373	0.0267	0.0287	0.0197	72.6	278.4	78.4	329.9	179.0
15 years (2018-2032)	0.0278	0.0198	0.0210	0.0143	71.0	327.9	76.7	388.5	208.5	0.0273	0.0195	0.0211	0.0144	52.3	392.6	56.5	465.3	225.4
30 years (2018-2047)	0.0173	0.0123	0.0130	0.0089	44.1	203.9	47.7	241.6	129.6	0.0170	0.0121	0.0131	0.0090	32.5	245.4	35.1	290.8	140.8

NOTES:

Avoided Costs are in Nominal Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (nominal $)

Zone: SWCT

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	95.9	2.2	12.9	7.6	2.7	12.9	7.8
2020	97.8	1.0	4.8	2.9	1.2	4.8	3.0
2021	99.8	0.3	8.2	4.3	0.4	8.2	4.3
2022	101.7	0.2	8.6	4.4	0.3	8.6	4.5
2023	103.8	0.1	6.5	3.3	0.2	8.9	4.6
2024	105.9	-	5.2	2.6	0.1	7.0	3.6
2025	108.0	-	9.5	4.8	-	10.3	5.2
2026	110.1	-	8.9	4.5	-	10.6	5.3
2027	112.3	-	7.7	3.8	-	10.0	5.0
2028	114.6	-	8.0	4.0	-	11.0	5.5
2029	116.9	-	5.3	2.7	-	8.6	4.3
2030	119.2	-	2.0	1.0	-	3.6	1.8
2031	121.6	-	1.3	0.7	-	2.9	1.5
2032	124.0	-	0.4	0.2	-	1.4	0.7
2033	126.5	-	-	-	-	0.2	0.1
2034	129.0	-	-	-	-	-	-
2035	131.6	-	-	-	-	-	-
2036	134.3	-	-	-	-	-	-
2037	136.9	-	-	-	-	-	-
2038	139.7	-	-	-	-	-	-
2039	142.5	-	-	-	-	-	-
2040	145.3	-	-	-	-	-	-
2041	148.2	-	-	-	-	-	-
2042	151.2	-	-	-	-	-	-
2043	154.2	-	-	-	-	-	-
2044	157.3	-	-	-	-	-	-
2045	160.4	-	-	-	-	-	-
2046	163.7	-	-	-	-	-	-
2047	166.9	-	-	-	-	-	-
2048	170.3	-	-	-	-	-	-
2049	173.7	-	-	-	-	-	-
2050	177.1	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	102.4	1.0	9.1	5.0	0.5	8.0	4.3
15 years (2018-2032)	107.1	0.7	7.5	4.1	0.4	7.3	3.9
30 years (2018-2047)	121.1	0.5	4.7	2.6	0.2	4.6	2.4

NOTES:
Avoided Costs are in Nominal Dollars
ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2 Uncleared capacity value includes reserve margin and uncleared load forecast effect
3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6 Assumes bid percentage of 50.0%
7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Massachusetts

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0476	0.0434	0.0318	0.0258	0.0039	0.0556	0.0510	0.0386	0.0320	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0488	0.0450	0.0318	0.0283	0.0082	0.0616	0.0575	0.0432	0.0395	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0519	0.0486	0.0377	0.0327	0.0085	0.0652	0.0617	0.0499	0.0445	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0544	0.0504	0.0455	0.0377	0.0066	0.0658	0.0616	0.0562	0.0478	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0540	0.0488	0.0446	0.0359	0.0027	0.0612	0.0556	0.0511	0.0417	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0551	0.0489	0.0417	0.0327	0.0029	0.0627	0.0559	0.0482	0.0385	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0586	0.0549	0.0411	0.0374	0.0029	0.0665	0.0624	0.0475	0.0435	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0553	0.0522	0.0431	0.0385	0.0025	0.0624	0.0590	0.0492	0.0442	65.7	53.9	70.9	63.9	67.4	0.0418	0.0427	0.0408	0.0410
2026	0.0554	0.0518	0.0468	0.0409	0.0023	0.0623	0.0585	0.0531	0.0467	71.2	74.9	76.9	88.7	82.8	0.0413	0.0421	0.0402	0.0405
2027	0.0600	0.0561	0.0447	0.0387	0.0021	0.0671	0.0628	0.0506	0.0441	76.9	89.5	83.0	106.1	94.5	0.0397	0.0405	0.0387	0.0389
2028	0.0618	0.0545	0.0488	0.0398	0.0020	0.0690	0.0610	0.0549	0.0451	82.5	94.8	89.1	112.3	100.7	0.0392	0.0400	0.0382	0.0384
2029	0.0636	0.0582	0.0479	0.0404	0.0019	0.0708	0.0650	0.0538	0.0458	88.1	101.0	95.2	119.7	107.4	0.0379	0.0387	0.0369	0.0371
2030	0.0585	0.0552	0.0505	0.0461	0.0018	0.0652	0.0616	0.0565	0.0517	83.9	97.7	90.6	115.8	103.2	0.0363	0.0370	0.0353	0.0356
2031	0.0582	0.0544	0.0459	0.0399	0.0018	0.0648	0.0607	0.0515	0.0451	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0568	0.0528	0.0468	0.0404	0.0024	0.0640	0.0596	0.0532	0.0463	88.1	101.0	95.2	119.7	107.4	0.0386	0.0394	0.0376	0.0378
2033	0.0614	0.0539	0.0476	0.0388	0.0026	0.0691	0.0610	0.0541	0.0446	83.9	97.7	90.6	115.8	103.2	0.0378	0.0387	0.0369	0.0371
2034	0.0605	0.0508	0.0505	0.0396	0.0027	0.0683	0.0577	0.0574	0.0457	82.5	94.8	89.1	112.3	100.7	0.0377	0.0385	0.0368	0.0370
2035	0.0626	0.0558	0.0562	0.0475	0.0028	0.0706	0.0633	0.0637	0.0543	88.1	101.0	95.2	119.7	107.4	0.0349	0.0356	0.0340	0.0342
2036	0.0637	0.0562	0.0591	0.0496	0.0031	0.0722	0.0641	0.0672	0.0569	89.6	102.6	96.8	121.6	109.2	0.0338	0.0345	0.0329	0.0331
2037	0.0649	0.0566	0.0622	0.0517	0.0035	0.0739	0.0648	0.0709	0.0596	91.1	104.3	98.4	123.6	111.0	0.0327	0.0334	0.0318	0.0320
2038	0.0661	0.0569	0.0654	0.0540	0.0039	0.0756	0.0657	0.0748	0.0625	92.6	105.9	100.0	125.5	112.8	0.0316	0.0323	0.0308	0.0310
2039	0.0673	0.0573	0.0688	0.0564	0.0043	0.0774	0.0665	0.0789	0.0656	94.2	107.6	101.7	127.5	114.6	0.0306	0.0312	0.0298	0.0300
2040	0.0686	0.0577	0.0724	0.0589	0.0048	0.0793	0.0675	0.0833	0.0688	95.7	109.3	103.4	129.6	116.5	0.0296	0.0302	0.0288	0.0290
2041	0.0699	0.0581	0.0761	0.0615	0.0053	0.0812	0.0685	0.0880	0.0722	97.3	111.1	105.1	131.7	118.4	0.0286	0.0292	0.0279	0.0280
2042	0.0712	0.0584	0.0801	0.0643	0.0059	0.0833	0.0695	0.0929	0.0758	98.9	112.9	106.9	133.8	120.3	0.0277	0.0282	0.0269	0.0271
2043	0.0725	0.0588	0.0842	0.0671	0.0066	0.0854	0.0707	0.0981	0.0796	100.6	114.7	108.6	135.9	122.3	0.0268	0.0273	0.0261	0.0262
2044	0.0738	0.0592	0.0886	0.0701	0.0074	0.0877	0.0719	0.1036	0.0836	102.3	116.5	110.5	138.1	124.3	0.0259	0.0264	0.0252	0.0254
2045	0.0752	0.0596	0.0932	0.0732	0.0082	0.0901	0.0732	0.1095	0.0879	104.0	118.4	112.3	140.3	126.3	0.0250	0.0256	0.0244	0.0245
2046	0.0766	0.0600	0.0980	0.0764	0.0091	0.0926	0.0747	0.1157	0.0924	105.7	120.3	114.2	142.5	128.3	0.0242	0.0247	0.0236	0.0237
2047	0.0780	0.0604	0.1031	0.0798	0.0102	0.0952	0.0762	0.1224	0.0972	107.5	122.2	116.1	144.8	130.4	0.0234	0.0239	0.0228	0.0230
2048	0.0794	0.0608	0.1085	0.0833	0.0113	0.0980	0.0779	0.1294	0.1022	109.3	124.2	118.0	147.1	132.6	0.0227	0.0231	0.0221	0.0222
2049	0.0809	0.0612	0.1141	0.0870	0.0126	0.1010	0.0797	0.1369	0.1076	111.1	126.1	120.0	149.5	134.7	0.0219	0.0224	0.0213	0.0215
2050	0.0824	0.0616	0.1200	0.0909	0.0140	0.1042	0.0817	0.1448	0.1133	112.9	128.2	122.0	151.9	136.9	0.0212	0.0216	0.0207	0.0208
Levelized Costs																		
10 years (2018-2027)	0.0540	0.0499	0.0407	0.0347	0.0043	0.0630	0.0585	0.0486	0.0422	73.3	26.4	79.2	31.2	55.2	0.0429	0.0438	0.0418	0.0420
15 years (2018-2032)	0.0558	0.0515	0.0430	0.0368	0.0036	0.0642	0.0595	0.0503	0.0436	76.9	48.6	83.1	57.6	70.4	0.0415	0.0424	0.0404	0.0407
30 years (2018-2047)	0.0615	0.0540	0.0564	0.0466	0.0043	0.0711	0.0631	0.0656	0.0550	85.1	75.7	92.0	89.7	90.8	0.0364	0.0372	0.0355	0.0357

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: Massachusetts

	Intrastate								
	DRIPE: 2018 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)
2018	0.0196	0.0136	0.0135	0.0089	239.6	-	258.8	-	129.4
2019	0.0306	0.0212	0.0205	0.0150	126.0	-	136.0	-	68.0
2020	0.0351	0.0251	0.0262	0.0183	153.4	-	165.7	-	82.8
2021	0.0370	0.0263	0.0319	0.0216	25.6	-	27.6	-	13.8
2022	0.0331	0.0228	0.0283	0.0182	17.1	-	18.5	-	9.2
2023	0.0226	0.0151	0.0176	0.0112	-	16.4	-	19.5	9.7
2024	0.0183	0.0132	0.0131	0.0098	-	28.7	-	34.1	17.0
2025	0.0120	0.0087	0.0097	0.0071	-	472.2	-	559.5	279.8
2026	0.0062	0.0044	0.0054	0.0038	-	558.7	-	662.1	331.0
2027	0.0038	0.0028	0.0029	0.0021	-	547.1	-	648.4	324.2
2028	-	-	-	-	-	419.1	-	496.7	248.3
2029	-	-	-	-	-	275.6	-	326.6	163.3
2030	-	-	-	-	-	134.2	-	159.0	79.5
2031	-	-	-	-	-	62.7	-	74.3	37.1
2032	-	-	-	-	-	18.2	-	21.5	10.8
2033	-	-	-	-	-	-	-	-	-
2034	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-
Levelized Costs									
10 years (2018-2027)	0.0222	0.0156	0.0171	0.0117	58.8	163.3	63.5	193.6	123.5
15 years (2018-2032)	0.0153	0.0107	0.0118	0.0081	40.5	173.1	43.7	205.2	119.1
30 years (2018-2047)	0.0084	0.0059	0.0065	0.0044	22.3	95.2	24.0	112.8	65.5

	Intrastate									Wholesale Cross-DRIPE[7]	
	DRIPE: 2019 vintage measures										
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	-	-	-	-	-	-	-	-	-	0.0075	0.0000
2019	0.0197	0.0137	0.0133	0.0097	151.7	-	163.9	-	81.9	0.0118	0.0074
2020	0.0325	0.0233	0.0243	0.0169	190.0	-	205.3	-	102.6	0.0130	0.0116
2021	0.0364	0.0259	0.0314	0.0212	34.3	-	37.0	-	18.5	0.0132	0.0119
2022	0.0365	0.0251	0.0312	0.0200	25.9	-	28.0	-	14.0	0.0120	0.0120
2023	0.0284	0.0189	0.0222	0.0140	17.3	-	18.6	-	9.3	0.0088	0.0088
2024	0.0236	0.0170	0.0169	0.0126	-	16.7	-	19.8	9.9	0.0057	0.0057
2025	0.0166	0.0120	0.0133	0.0098	-	370.3	-	438.8	219.4	0.0044	0.0044
2026	0.0116	0.0082	0.0100	0.0070	-	505.3	-	598.8	299.4	0.0030	0.0030
2027	0.0065	0.0047	0.0050	0.0035	-	588.3	-	697.2	348.6	0.0018	0.0018
2028	0.0038	0.0026	0.0031	0.0021	-	577.9	-	684.9	342.4	0.0005	0.0005
2029	-	-	-	-	-	445.5	-	527.9	264.0	0.0006	0.0006
2030	-	-	-	-	-	245.5	-	290.9	145.5	0.0006	0.0006
2031	-	-	-	-	-	141.7	-	167.9	84.0	0.0006	0.0006
2032	-	-	-	-	-	66.6	-	79.0	39.5	0.0006	0.0006
2033	-	-	-	-	-	16.2	-	19.2	9.6	0.0006	0.0006
2034	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2035	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2036	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2037	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2038	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2039	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2040	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2041	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2042	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2043	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2044	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2045	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2046	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2047	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2048	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2049	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2050	-	-	-	-	-	-	-	-	-	0.0006	0.0006
Levelized Costs											
10 years (2018-2027)	0.0212	0.0149	0.0168	0.0115	43.3	150.7	46.8	178.6	106.9	0.0082	0.0067
15 years (2018-2032)	0.0149	0.0104	0.0118	0.0081	29.8	203.3	32.2	240.9	128.8	0.0058	0.0048
30 years (2018-2047)	0.0082	0.0057	0.0065	0.0044	16.4	112.4	17.7	133.1	71.1	0.0035	0.0029

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **Massachusetts**

	Rest-of-Pool																		
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures									
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0192	0.0138	0.0128	0.0084	247.3	-	267.1	-	133.5	-	-	-	-	-	-	-	-	-
2019	0.0298	0.0213	0.0195	0.0140	129.1	-	139.4	-	69.7	0.0192	0.0137	0.0126	0.0090	155.5	-	167.9	-	84.0
2020	0.0340	0.0251	0.0247	0.0171	156.9	-	169.5	-	84.7	0.0315	0.0232	0.0228	0.0159	194.4	-	210.0	-	105.0
2021	0.0355	0.0261	0.0298	0.0200	26.1	-	28.2	-	14.1	0.0349	0.0257	0.0293	0.0197	35.0	-	37.8	-	18.9
2022	0.0317	0.0226	0.0264	0.0170	17.4	-	18.8	-	9.4	0.0349	0.0249	0.0291	0.0187	26.4	-	28.6	-	14.3
2023	0.0260	0.0180	0.0198	0.0125	-	16.7	-	19.8	9.9	0.0327	0.0226	0.0248	0.0157	17.5	-	18.9	-	9.5
2024	0.0210	0.0156	0.0146	0.0107	-	29.1	-	34.5	17.3	0.0271	0.0202	0.0189	0.0138	-	16.9	-	20.0	10.0
2025	0.0142	0.0106	0.0110	0.0080	-	478.1	-	566.6	283.3	0.0195	0.0146	0.0152	0.0110	-	375.0	-	444.3	222.2
2026	0.0075	0.0055	0.0063	0.0044	-	563.4	-	667.6	333.8	0.0139	0.0102	0.0118	0.0082	-	509.5	-	603.8	301.9
2027	0.0046	0.0034	0.0034	0.0024	-	551.7	-	653.8	326.9	0.0077	0.0058	0.0058	0.0040	-	593.2	-	703.0	351.5
2028	0.0000	0.0000	0.0000	0.0000	-	422.6	-	500.8	250.4	0.0045	0.0032	0.0036	0.0024	-	582.8	-	690.6	345.3
2029	0.0000	0.0000	0.0000	0.0000	-	277.9	-	329.4	164.7	-	-	-	-	-	449.2	-	532.3	266.2
2030	-	-	-	-	-	135.3	-	160.3	80.2	-	-	-	-	-	247.6	-	293.4	146.7
2031	-	-	-	-	-	63.2	-	74.9	37.5	-	-	-	-	-	142.9	-	169.3	84.7
2032	-	-	-	-	-	18.3	-	21.7	10.9	-	-	-	-	-	67.2	-	79.6	39.8
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.3	-	19.3	9.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0226	0.0164	0.0170	0.0116	60.4	164.9	65.2	195.5	125.3	0.0222	0.0161	0.0170	0.0116	44.3	152.1	47.9	180.3	108.3
15 years (2018-2032)	0.0156	0.0113	0.0117	0.0080	41.6	174.7	44.9	207.1	120.6	0.0156	0.0113	0.0120	0.0081	30.5	205.1	33.0	243.1	130.2
30 years (2018-2047)	0.0086	0.0062	0.0064	0.0044	22.9	96.1	24.7	113.9	66.3	0.0086	0.0062	0.0066	0.0045	16.8	113.4	18.1	134.3	71.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **Massachusetts**

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2 Uncleared capacity value includes reserve margin and uncleared load forecast effect
3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6 Assumes bid percentage of 50.0%
7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SEMA

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m *(1-%Bid)	o	p	q	r
2018	0.0475	0.0432	0.0319	0.0259	0.0039	0.0554	0.0509	0.0386	0.0322	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0495	0.0451	0.0320	0.0284	0.0082	0.0623	0.0576	0.0434	0.0396	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0519	0.0486	0.0379	0.0327	0.0085	0.0653	0.0616	0.0501	0.0446	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0549	0.0504	0.0457	0.0378	0.0066	0.0665	0.0616	0.0565	0.0479	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0544	0.0489	0.0448	0.0361	0.0027	0.0616	0.0558	0.0512	0.0418	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0551	0.0493	0.0418	0.0329	0.0029	0.0627	0.0563	0.0483	0.0387	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0588	0.0549	0.0412	0.0374	0.0029	0.0667	0.0624	0.0476	0.0436	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0554	0.0521	0.0431	0.0386	0.0025	0.0625	0.0589	0.0492	0.0443	65.7	53.9	70.9	63.9	67.4	0.0418	0.0427	0.0408	0.0410
2026	0.0554	0.0518	0.0469	0.0409	0.0023	0.0623	0.0585	0.0531	0.0467	71.2	74.9	76.9	88.7	82.8	0.0413	0.0421	0.0402	0.0405
2027	0.0599	0.0559	0.0447	0.0388	0.0021	0.0670	0.0627	0.0506	0.0442	76.9	89.5	83.0	106.1	94.5	0.0397	0.0405	0.0387	0.0389
2028	0.0617	0.0543	0.0489	0.0398	0.0020	0.0688	0.0609	0.0550	0.0452	82.5	94.8	89.1	112.3	100.7	0.0392	0.0400	0.0382	0.0384
2029	0.0635	0.0581	0.0479	0.0405	0.0019	0.0707	0.0649	0.0538	0.0458	88.1	101.0	95.2	119.7	107.4	0.0379	0.0387	0.0369	0.0371
2030	0.0584	0.0551	0.0505	0.0461	0.0018	0.0650	0.0614	0.0565	0.0518	83.9	97.7	90.6	115.8	103.2	0.0363	0.0370	0.0353	0.0356
2031	0.0581	0.0543	0.0461	0.0399	0.0018	0.0647	0.0606	0.0517	0.0451	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0568	0.0527	0.0469	0.0405	0.0024	0.0640	0.0595	0.0533	0.0464	88.1	101.0	95.2	119.7	107.4	0.0386	0.0394	0.0376	0.0378
2033	0.0614	0.0538	0.0477	0.0388	0.0026	0.0690	0.0609	0.0543	0.0447	83.9	97.7	90.6	115.8	103.2	0.0378	0.0387	0.0369	0.0371
2034	0.0604	0.0506	0.0505	0.0397	0.0027	0.0681	0.0575	0.0574	0.0457	82.5	94.8	89.1	112.3	100.7	0.0377	0.0385	0.0368	0.0370
2035	0.0625	0.0557	0.0562	0.0475	0.0028	0.0705	0.0632	0.0637	0.0543	88.1	101.0	95.2	119.7	107.4	0.0349	0.0356	0.0340	0.0342
2036	0.0636	0.0561	0.0590	0.0496	0.0031	0.0721	0.0639	0.0671	0.0569	89.6	102.6	96.8	121.6	109.2	0.0338	0.0345	0.0329	0.0331
2037	0.0648	0.0565	0.0620	0.0518	0.0035	0.0737	0.0647	0.0707	0.0597	91.1	104.3	98.4	123.6	111.0	0.0327	0.0334	0.0318	0.0320
2038	0.0660	0.0568	0.0652	0.0541	0.0039	0.0754	0.0656	0.0746	0.0626	92.6	105.9	100.0	125.5	112.8	0.0316	0.0323	0.0308	0.0310
2039	0.0672	0.0572	0.0685	0.0565	0.0043	0.0772	0.0664	0.0786	0.0657	94.2	107.6	101.7	127.5	114.6	0.0306	0.0312	0.0298	0.0300
2040	0.0684	0.0576	0.0719	0.0590	0.0048	0.0791	0.0674	0.0829	0.0689	95.7	109.3	103.4	129.6	116.5	0.0296	0.0302	0.0288	0.0290
2041	0.0697	0.0580	0.0756	0.0616	0.0053	0.0810	0.0684	0.0874	0.0723	97.3	111.1	105.1	131.7	118.4	0.0286	0.0292	0.0279	0.0280
2042	0.0709	0.0583	0.0794	0.0643	0.0059	0.0830	0.0694	0.0922	0.0759	98.9	112.9	106.9	133.8	120.3	0.0277	0.0282	0.0269	0.0271
2043	0.0722	0.0587	0.0834	0.0672	0.0066	0.0852	0.0706	0.0973	0.0797	100.6	114.7	108.6	135.9	122.3	0.0268	0.0273	0.0261	0.0262
2044	0.0736	0.0591	0.0877	0.0701	0.0074	0.0874	0.0718	0.1027	0.0837	102.3	116.5	110.5	138.1	124.3	0.0259	0.0264	0.0252	0.0254
2045	0.0749	0.0595	0.0921	0.0733	0.0082	0.0898	0.0731	0.1084	0.0880	104.0	118.4	112.3	140.3	126.3	0.0250	0.0256	0.0244	0.0245
2046	0.0763	0.0599	0.0968	0.0765	0.0091	0.0923	0.0745	0.1144	0.0925	105.7	120.3	114.2	142.5	128.3	0.0242	0.0247	0.0236	0.0237
2047	0.0777	0.0603	0.1017	0.0799	0.0102	0.0949	0.0761	0.1208	0.0973	107.5	122.2	116.1	144.8	130.4	0.0234	0.0239	0.0228	0.0230
2048	0.0791	0.0607	0.1069	0.0834	0.0113	0.0977	0.0778	0.1277	0.1023	109.3	124.2	118.0	147.1	132.6	0.0227	0.0231	0.0221	0.0222
2049	0.0806	0.0611	0.1123	0.0871	0.0126	0.1006	0.0796	0.1349	0.1077	111.1	126.1	120.0	149.5	134.7	0.0219	0.0224	0.0213	0.0215
2050	0.0820	0.0615	0.1180	0.0910	0.0140	0.1038	0.0816	0.1426	0.1134	112.9	128.2	122.0	151.9	136.9	0.0212	0.0216	0.0207	0.0208
Levelized Costs																		
10 years (2018-2027)	0.0542	0.0499	0.0408	0.0348	0.0043	0.0632	0.0586	0.0488	0.0423	73.3	26.4	79.2	31.2	55.2	0.0429	0.0438	0.0418	0.0420
15 years (2018-2032)	0.0559	0.0515	0.0431	0.0368	0.0036	0.0643	0.0595	0.0504	0.0437	76.9	48.6	83.1	57.6	70.4	0.0415	0.0424	0.0404	0.0407
30 years (2018-2047)	0.0615	0.0540	0.0562	0.0466	0.0043	0.0711	0.0630	0.0654	0.0551	85.1	75.7	92.0	89.7	90.8	0.0364	0.0372	0.0355	0.0357

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SEMA

	Intrastate																			Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures											
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0196	0.0136	0.0135	0.0089	239.6	-	258.8	-	129.4	-	-	-	-	-	-	-	-	-	0.0075	0.0000
2019	0.0306	0.0212	0.0205	0.0150	126.0	-	136.0	-	68.0	0.0197	0.0137	0.0133	0.0097	151.7	-	163.9	-	81.9	0.0118	0.0074
2020	0.0351	0.0251	0.0262	0.0183	153.4	-	165.7	-	82.8	0.0325	0.0233	0.0243	0.0169	190.0	-	205.3	-	102.6	0.0130	0.0116
2021	0.0370	0.0263	0.0319	0.0216	25.6	-	27.6	-	13.8	0.0364	0.0259	0.0314	0.0212	34.3	-	37.0	-	18.5	0.0132	0.0119
2022	0.0331	0.0228	0.0283	0.0182	17.1	-	18.5	-	9.2	0.0365	0.0251	0.0312	0.0200	25.9	-	28.0	-	14.0	0.0120	0.0120
2023	0.0226	0.0151	0.0176	0.0112	-	16.4	-	19.5	9.7	0.0284	0.0189	0.0222	0.0140	17.3	-	18.6	-	9.3	0.0088	0.0088
2024	0.0183	0.0132	0.0131	0.0098	-	28.7	-	34.1	17.0	0.0236	0.0170	0.0169	0.0126	-	16.7	-	19.8	9.9	0.0057	0.0057
2025	0.0120	0.0087	0.0097	0.0071	-	472.2	-	559.5	279.8	0.0166	0.0120	0.0133	0.0098	-	370.3	-	438.8	219.4	0.0044	0.0044
2026	0.0062	0.0044	0.0054	0.0038	-	558.7	-	662.1	331.0	0.0116	0.0082	0.0100	0.0070	-	505.3	-	598.8	299.4	0.0030	0.0030
2027	0.0038	0.0028	0.0029	0.0021	-	547.1	-	648.4	324.2	0.0065	0.0047	0.0050	0.0035	-	588.3	-	697.2	348.6	0.0018	0.0018
2028	-	-	-	-	-	419.1	-	496.7	248.3	0.0038	0.0026	0.0031	0.0021	-	577.9	-	684.9	342.4	0.0005	0.0005
2029	-	-	-	-	-	275.6	-	326.6	163.3	-	-	-	-	-	445.5	-	527.9	264.0	0.0006	0.0006
2030	-	-	-	-	-	134.2	-	159.0	79.5	-	-	-	-	-	245.5	-	290.9	145.5	0.0006	0.0006
2031	-	-	-	-	-	62.7	-	74.3	37.1	-	-	-	-	-	141.7	-	167.9	84.0	0.0006	0.0006
2032	-	-	-	-	-	18.2	-	21.5	10.8	-	-	-	-	-	66.6	-	79.0	39.5	0.0006	0.0006
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.2	-	19.2	9.6	0.0006	0.0006
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
Levelized Costs																				
10 years (2018-2027)	0.0222	0.0156	0.0171	0.0117	58.8	163.3	63.5	193.6	123.5	0.0212	0.0149	0.0168	0.0115	43.3	150.7	46.8	178.6	106.9	0.0082	0.0067
15 years (2018-2032)	0.0153	0.0107	0.0118	0.0081	40.5	173.1	43.7	205.2	119.1	0.0149	0.0104	0.0118	0.0081	29.8	203.3	32.2	240.9	128.8	0.0058	0.0048
30 years (2018-2047)	0.0084	0.0059	0.0065	0.0044	22.3	95.2	24.0	112.8	65.5	0.0082	0.0057	0.0065	0.0044	16.4	112.4	17.7	133.1	71.1	0.0035	0.0029

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SEMA

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0192	0.0138	0.0128	0.0084	247.3	-	267.1	-	133.5	-	-	-	-	-	-	-	-	-
2019	0.0298	0.0213	0.0195	0.0140	129.1	-	139.4	-	69.7	0.0192	0.0137	0.0126	0.0090	155.5	-	167.9	-	84.0
2020	0.0340	0.0251	0.0247	0.0171	156.9	-	169.5	-	84.7	0.0315	0.0232	0.0228	0.0159	194.4	-	210.0	-	105.0
2021	0.0355	0.0261	0.0298	0.0200	26.1	-	28.2	-	14.1	0.0349	0.0257	0.0293	0.0197	35.0	-	37.8	-	18.9
2022	0.0317	0.0226	0.0264	0.0170	17.4	-	18.8	-	9.4	0.0349	0.0249	0.0291	0.0187	26.4	-	28.6	-	14.3
2023	0.0260	0.0180	0.0198	0.0125	-	16.7	-	19.8	9.9	0.0327	0.0226	0.0248	0.0157	17.5	-	18.9	-	9.5
2024	0.0210	0.0156	0.0146	0.0107	-	29.1	-	34.5	17.3	0.0271	0.0202	0.0189	0.0138	-	16.9	-	20.0	10.0
2025	0.0142	0.0106	0.0110	0.0080	-	478.1	-	566.6	283.3	0.0195	0.0146	0.0152	0.0110	-	375.0	-	444.3	222.2
2026	0.0075	0.0055	0.0063	0.0044	-	563.4	-	667.6	333.8	0.0139	0.0102	0.0118	0.0082	-	509.5	-	603.8	301.9
2027	0.0046	0.0034	0.0034	0.0024	-	551.7	-	653.8	326.9	0.0077	0.0058	0.0058	0.0040	-	593.2	-	703.0	351.5
2028	0.0000	0.0000	0.0000	0.0000	-	422.6	-	500.8	250.4	0.0045	0.0032	0.0036	0.0024	-	582.8	-	690.6	345.3
2029	0.0000	0.0000	0.0000	0.0000	-	277.9	-	329.4	164.7	-	-	-	-	-	449.2	-	532.3	266.2
2030	-	-	-	-	-	135.3	-	160.3	80.2	-	-	-	-	-	247.6	-	293.4	146.7
2031	-	-	-	-	-	63.2	-	74.9	37.5	-	-	-	-	-	142.9	-	169.3	84.7
2032	-	-	-	-	-	18.3	-	21.7	10.9	-	-	-	-	-	67.2	-	79.6	39.8
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.3	-	19.3	9.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0226	0.0164	0.0170	0.0116	60.4	164.9	65.2	195.5	125.3	0.0222	0.0161	0.0170	0.0116	44.3	152.1	47.9	180.3	108.3
15 years (2018-2032)	0.0156	0.0113	0.0117	0.0080	41.6	174.7	44.9	207.1	120.6	0.0156	0.0113	0.0120	0.0081	30.5	205.1	33.0	243.1	130.2
30 years (2018-2047)	0.0086	0.0062	0.0064	0.0044	22.9	96.1	24.7	113.9	66.3	0.0086	0.0062	0.0066	0.0045	16.8	113.4	18.1	134.3	71.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: SEMA

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: NEMA

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0477	0.0435	0.0318	0.0257	0.0039	0.0557	0.0512	0.0386	0.0320	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0485	0.0450	0.0317	0.0283	0.0082	0.0613	0.0575	0.0432	0.0395	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0519	0.0487	0.0376	0.0326	0.0085	0.0652	0.0618	0.0498	0.0444	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0542	0.0505	0.0454	0.0377	0.0066	0.0656	0.0617	0.0562	0.0478	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0538	0.0488	0.0446	0.0359	0.0027	0.0610	0.0556	0.0510	0.0416	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0551	0.0488	0.0417	0.0326	0.0029	0.0627	0.0558	0.0481	0.0384	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0586	0.0549	0.0410	0.0373	0.0029	0.0664	0.0624	0.0474	0.0434	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0554	0.0523	0.0431	0.0385	0.0025	0.0625	0.0591	0.0492	0.0442	65.7	53.9	70.9	63.9	67.4	0.0418	0.0427	0.0408	0.0410
2026	0.0554	0.0519	0.0468	0.0409	0.0023	0.0624	0.0586	0.0530	0.0467	71.2	74.9	76.9	88.7	82.8	0.0413	0.0421	0.0402	0.0405
2027	0.0601	0.0562	0.0447	0.0387	0.0021	0.0672	0.0630	0.0506	0.0441	76.9	89.5	83.0	106.1	94.5	0.0397	0.0405	0.0387	0.0389
2028	0.0619	0.0546	0.0488	0.0397	0.0020	0.0690	0.0611	0.0549	0.0451	82.5	94.8	89.1	112.3	100.7	0.0392	0.0400	0.0382	0.0384
2029	0.0637	0.0583	0.0479	0.0404	0.0019	0.0709	0.0650	0.0538	0.0458	88.1	101.0	95.2	119.7	107.4	0.0379	0.0387	0.0369	0.0371
2030	0.0586	0.0553	0.0505	0.0460	0.0018	0.0653	0.0617	0.0565	0.0517	83.9	97.7	90.6	115.8	103.2	0.0363	0.0370	0.0353	0.0356
2031	0.0582	0.0545	0.0458	0.0399	0.0018	0.0649	0.0608	0.0515	0.0451	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0569	0.0528	0.0468	0.0404	0.0024	0.0641	0.0597	0.0532	0.0463	88.1	101.0	95.2	119.7	107.4	0.0386	0.0394	0.0376	0.0378
2033	0.0615	0.0540	0.0475	0.0387	0.0026	0.0692	0.0610	0.0541	0.0446	83.9	97.7	90.6	115.8	103.2	0.0378	0.0387	0.0369	0.0371
2034	0.0606	0.0509	0.0505	0.0396	0.0027	0.0684	0.0578	0.0574	0.0456	82.5	94.8	89.1	112.3	100.7	0.0377	0.0385	0.0368	0.0370
2035	0.0627	0.0559	0.0562	0.0474	0.0028	0.0707	0.0634	0.0637	0.0543	88.1	101.0	95.2	119.7	107.4	0.0349	0.0356	0.0340	0.0342
2036	0.0638	0.0563	0.0591	0.0495	0.0031	0.0723	0.0642	0.0673	0.0569	89.6	102.6	96.8	121.6	109.2	0.0338	0.0345	0.0329	0.0331
2037	0.0650	0.0567	0.0622	0.0517	0.0035	0.0740	0.0649	0.0710	0.0596	91.1	104.3	98.4	123.6	111.0	0.0327	0.0334	0.0318	0.0320
2038	0.0662	0.0570	0.0655	0.0540	0.0039	0.0757	0.0658	0.0749	0.0625	92.6	105.9	100.0	125.5	112.8	0.0316	0.0323	0.0308	0.0310
2039	0.0675	0.0574	0.0689	0.0564	0.0043	0.0775	0.0666	0.0791	0.0656	94.2	107.6	101.7	127.5	114.6	0.0306	0.0312	0.0298	0.0300
2040	0.0687	0.0578	0.0726	0.0589	0.0048	0.0794	0.0676	0.0835	0.0688	95.7	109.3	103.4	129.6	116.5	0.0296	0.0302	0.0288	0.0290
2041	0.0700	0.0581	0.0764	0.0615	0.0053	0.0814	0.0686	0.0882	0.0722	97.3	111.1	105.1	131.7	118.4	0.0286	0.0292	0.0279	0.0280
2042	0.0713	0.0585	0.0804	0.0642	0.0059	0.0834	0.0696	0.0932	0.0758	98.9	112.9	106.9	133.8	120.3	0.0277	0.0282	0.0269	0.0271
2043	0.0726	0.0589	0.0846	0.0671	0.0066	0.0856	0.0708	0.0985	0.0796	100.6	114.7	108.6	135.9	122.3	0.0268	0.0273	0.0261	0.0262
2044	0.0740	0.0593	0.0890	0.0700	0.0074	0.0878	0.0720	0.1041	0.0836	102.3	116.5	110.5	138.1	124.3	0.0259	0.0264	0.0252	0.0254
2045	0.0753	0.0597	0.0937	0.0731	0.0082	0.0902	0.0733	0.1100	0.0879	104.0	118.4	112.3	140.3	126.3	0.0250	0.0256	0.0244	0.0245
2046	0.0767	0.0601	0.0986	0.0764	0.0091	0.0927	0.0748	0.1163	0.0924	105.7	120.3	114.2	142.5	128.3	0.0242	0.0247	0.0236	0.0237
2047	0.0782	0.0605	0.1037	0.0797	0.0102	0.0954	0.0763	0.1230	0.0971	107.5	122.2	116.1	144.8	130.4	0.0234	0.0239	0.0228	0.0230
2048	0.0796	0.0609	0.1092	0.0833	0.0113	0.0982	0.0780	0.1302	0.1022	109.3	124.2	118.0	147.1	132.6	0.0227	0.0231	0.0221	0.0222
2049	0.0811	0.0613	0.1149	0.0870	0.0126	0.1012	0.0798	0.1377	0.1075	111.1	126.1	120.0	149.5	134.7	0.0219	0.0224	0.0213	0.0215
2050	0.0826	0.0617	0.1209	0.0908	0.0140	0.1044	0.0818	0.1458	0.1132	112.9	128.2	122.0	151.9	136.9	0.0212	0.0216	0.0207	0.0208
Levelized Costs																		
10 years (2018-2027)	0.0539	0.0499	0.0407	0.0347	0.0043	0.0629	0.0586	0.0486	0.0421	73.3	26.4	79.2	31.2	55.2	0.0429	0.0438	0.0418	0.0420
15 years (2018-2032)	0.0558	0.0515	0.0430	0.0367	0.0036	0.0642	0.0596	0.0503	0.0436	76.9	48.6	83.1	57.6	70.4	0.0415	0.0424	0.0404	0.0407
30 years (2018-2047)	0.0616	0.0541	0.0565	0.0465	0.0043	0.0712	0.0631	0.0657	0.0550	85.1	75.7	92.0	89.7	90.8	0.0364	0.0372	0.0355	0.0357

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2 Uncleared capacity value includes reserve margin and uncleared load forecast effect
3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6 Assumes bid percentage of 50.0%
7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **NEMA**

	Intrastate																		Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures										
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]				
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)	kk	ll
2018	0.0196	0.0136	0.0135	0.0089	239.6	-	258.8	-	129.4	-	-	-	-	-	-	-	-	-	0.0075	0.0000
2019	0.0306	0.0212	0.0205	0.0150	126.0	-	136.0	-	68.0	0.0197	0.0137	0.0133	0.0097	151.7	-	163.9	-	81.9	0.0118	0.0074
2020	0.0351	0.0251	0.0262	0.0183	153.4	-	165.7	-	82.8	0.0325	0.0233	0.0243	0.0169	190.0	-	205.3	-	102.6	0.0130	0.0116
2021	0.0370	0.0263	0.0319	0.0216	25.6	-	27.6	-	13.8	0.0364	0.0259	0.0314	0.0212	34.3	-	37.0	-	18.5	0.0132	0.0119
2022	0.0331	0.0228	0.0283	0.0182	17.1	-	18.5	-	9.2	0.0365	0.0251	0.0312	0.0200	25.9	-	28.0	-	14.0	0.0120	0.0120
2023	0.0226	0.0151	0.0176	0.0112	-	16.4	-	19.5	9.7	0.0284	0.0189	0.0222	0.0140	17.3	-	18.6	-	9.3	0.0088	0.0088
2024	0.0183	0.0132	0.0131	0.0098	-	28.7	-	34.1	17.0	0.0236	0.0170	0.0169	0.0126	-	16.7	-	19.8	9.9	0.0057	0.0057
2025	0.0120	0.0087	0.0097	0.0071	-	472.2	-	559.5	279.8	0.0166	0.0120	0.0133	0.0098	-	370.3	-	438.8	219.4	0.0044	0.0044
2026	0.0062	0.0044	0.0054	0.0038	-	558.7	-	662.1	331.0	0.0116	0.0082	0.0100	0.0070	-	505.3	-	598.8	299.4	0.0030	0.0030
2027	0.0038	0.0028	0.0029	0.0021	-	547.1	-	648.4	324.2	0.0065	0.0047	0.0050	0.0035	-	588.3	-	697.2	348.6	0.0018	0.0018
2028	-	-	-	-	-	419.1	-	496.7	248.3	0.0038	0.0026	0.0031	0.0021	-	577.9	-	684.9	342.4	0.0005	0.0005
2029	-	-	-	-	-	275.6	-	326.6	163.3	-	-	-	-	-	445.5	-	527.9	264.0	0.0006	0.0006
2030	-	-	-	-	-	134.2	-	159.0	79.5	-	-	-	-	-	245.5	-	290.9	145.5	0.0006	0.0006
2031	-	-	-	-	-	62.7	-	74.3	37.1	-	-	-	-	-	141.7	-	167.9	84.0	0.0006	0.0006
2032	-	-	-	-	-	18.2	-	21.5	10.8	-	-	-	-	-	66.6	-	79.0	39.5	0.0006	0.0006
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.2	-	19.2	9.6	0.0006	0.0006
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
Levelized Costs																				
10 years (2018-2027)	0.0222	0.0156	0.0171	0.0117	58.8	163.3	63.5	193.6	123.5	0.0212	0.0149	0.0168	0.0115	43.3	150.7	46.8	178.6	106.9	0.0082	0.0067
15 years (2018-2032)	0.0153	0.0107	0.0118	0.0081	40.5	173.1	43.7	205.2	119.1	0.0149	0.0104	0.0118	0.0081	29.8	203.3	32.2	240.9	128.8	0.0058	0.0048
30 years (2018-2047)	0.0084	0.0059	0.0065	0.0044	22.3	95.2	24.0	112.8	65.5	0.0082	0.0057	0.0065	0.0044	16.4	112.4	17.7	133.1	71.1	0.0035	0.0029

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: **NEMA**

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0192	0.0138	0.0128	0.0084	247.3	-	267.1	-	133.5	-	-	-	-	-	-	-	-	-
2019	0.0298	0.0213	0.0195	0.0140	129.1	-	139.4	-	69.7	0.0192	0.0137	0.0126	0.0090	155.5	-	167.9	-	84.0
2020	0.0340	0.0251	0.0247	0.0171	156.9	-	169.5	-	84.7	0.0315	0.0232	0.0228	0.0159	194.4	-	210.0	-	105.0
2021	0.0355	0.0261	0.0298	0.0200	26.1	-	28.2	-	14.1	0.0349	0.0257	0.0293	0.0197	35.0	-	37.8	-	18.9
2022	0.0317	0.0226	0.0264	0.0170	17.4	-	18.8	-	9.4	0.0349	0.0249	0.0291	0.0187	26.4	-	28.6	-	14.3
2023	0.0260	0.0180	0.0198	0.0125	-	16.7	-	19.8	9.9	0.0327	0.0226	0.0248	0.0157	17.5	-	18.9	-	9.5
2024	0.0210	0.0156	0.0146	0.0107	-	29.1	-	34.5	17.3	0.0271	0.0202	0.0189	0.0138	-	16.9	-	20.0	10.0
2025	0.0142	0.0106	0.0110	0.0080	-	478.1	-	566.6	283.3	0.0195	0.0146	0.0152	0.0110	-	375.0	-	444.3	222.2
2026	0.0075	0.0055	0.0063	0.0044	-	563.4	-	667.6	333.8	0.0139	0.0102	0.0118	0.0082	-	509.5	-	603.8	301.9
2027	0.0046	0.0034	0.0034	0.0024	-	551.7	-	653.8	326.9	0.0077	0.0058	0.0058	0.0040	-	593.2	-	703.0	351.5
2028	0.0000	0.0000	0.0000	0.0000	-	422.6	-	500.8	250.4	0.0045	0.0032	0.0036	0.0024	-	582.8	-	690.6	345.3
2029	0.0000	0.0000	0.0000	0.0000	-	277.9	-	329.4	164.7	-	-	-	-	-	449.2	-	532.3	266.2
2030	-	-	-	-	-	135.3	-	160.3	80.2	-	-	-	-	-	247.6	-	293.4	146.7
2031	-	-	-	-	-	63.2	-	74.9	37.5	-	-	-	-	-	142.9	-	169.3	84.7
2032	-	-	-	-	-	18.3	-	21.7	10.9	-	-	-	-	-	67.2	-	79.6	39.8
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.3	-	19.3	9.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0226	0.0164	0.0170	0.0116	60.4	164.9	65.2	195.5	125.3	0.0222	0.0161	0.0170	0.0116	44.3	152.1	47.9	180.3	108.3
15 years (2018-2032)	0.0156	0.0113	0.0117	0.0080	41.6	174.7	44.9	207.1	120.6	0.0156	0.0113	0.0120	0.0081	30.5	205.1	33.0	243.1	130.2
30 years (2018-2047)	0.0086	0.0062	0.0064	0.0044	22.9	96.1	24.7	113.9	66.3	0.0086	0.0062	0.0066	0.0045	16.8	113.4	18.1	134.3	71.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: NEMA

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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

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5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: WCMA

	Wholesale Cost of Electric Energy				Wholesale REC Costs	Retail Cost of Electric Energy[1]				Wholesale Capacity Values		Retail Cost of Electric Capacity[3]			Wholesale Non-Embedded Costs			
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak		Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared (FCA Price)	Uncleared [2]	Cleared[4]	Uncleared [5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh
Period:	a	b	c	d	e	f =(a+e)*(1+WRP)	g =(b+e)*(1+WRP)	h =(c+e)*(1+WRP)	i =(d+e)*(1+WRP)	j	k	l=j*DL	m=k*(1+PTF Loss)*(1+WRP)*(1+DL)	n = (l*%Bid)+m*(1-%Bid)	o	p	q	r
2018	0.0476	0.0434	0.0318	0.0257	0.0039	0.0555	0.0510	0.0385	0.0320	104.5	0.0	112.9	0.0	56.4	0.0459	0.0469	0.0447	0.0450
2019	0.0484	0.0449	0.0317	0.0283	0.0082	0.0612	0.0574	0.0431	0.0395	100.0	0.0	108.0	0.0	54.0	0.0446	0.0456	0.0435	0.0438
2020	0.0517	0.0485	0.0375	0.0326	0.0085	0.0651	0.0616	0.0498	0.0444	73.9	0.0	79.8	0.0	39.9	0.0434	0.0444	0.0423	0.0426
2021	0.0540	0.0504	0.0453	0.0376	0.0066	0.0655	0.0615	0.0561	0.0478	59.9	0.0	64.7	0.0	32.4	0.0432	0.0441	0.0421	0.0424
2022	0.0537	0.0487	0.0445	0.0359	0.0027	0.0609	0.0554	0.0510	0.0416	57.6	0.0	62.2	0.0	31.1	0.0430	0.0439	0.0419	0.0421
2023	0.0550	0.0487	0.0416	0.0326	0.0029	0.0626	0.0557	0.0481	0.0384	58.8	20.8	63.5	24.6	44.1	0.0428	0.0437	0.0417	0.0419
2024	0.0585	0.0547	0.0410	0.0373	0.0029	0.0663	0.0622	0.0474	0.0434	61.2	36.0	66.1	42.7	54.4	0.0424	0.0433	0.0413	0.0416
2025	0.0552	0.0521	0.0430	0.0384	0.0025	0.0623	0.0590	0.0491	0.0442	65.7	53.9	70.9	63.9	67.4	0.0418	0.0427	0.0408	0.0410
2026	0.0554	0.0518	0.0467	0.0408	0.0023	0.0623	0.0585	0.0530	0.0466	71.2	74.9	76.9	88.7	82.8	0.0413	0.0421	0.0402	0.0405
2027	0.0599	0.0560	0.0447	0.0387	0.0021	0.0670	0.0628	0.0505	0.0441	76.9	89.5	83.0	106.1	94.5	0.0397	0.0405	0.0387	0.0389
2028	0.0618	0.0544	0.0488	0.0397	0.0020	0.0689	0.0610	0.0549	0.0451	82.5	94.8	89.1	112.3	100.7	0.0392	0.0400	0.0382	0.0384
2029	0.0636	0.0582	0.0478	0.0404	0.0019	0.0708	0.0649	0.0537	0.0457	88.1	101.0	95.2	119.7	107.4	0.0379	0.0387	0.0369	0.0371
2030	0.0585	0.0551	0.0505	0.0460	0.0018	0.0652	0.0615	0.0565	0.0517	83.9	97.7	90.6	115.8	103.2	0.0363	0.0370	0.0353	0.0356
2031	0.0581	0.0543	0.0458	0.0399	0.0018	0.0647	0.0607	0.0514	0.0450	82.5	94.8	89.1	112.3	100.7	0.0399	0.0407	0.0388	0.0391
2032	0.0567	0.0527	0.0467	0.0404	0.0024	0.0639	0.0596	0.0531	0.0463	88.1	101.0	95.2	119.7	107.4	0.0386	0.0394	0.0376	0.0378
2033	0.0614	0.0538	0.0475	0.0387	0.0026	0.0690	0.0609	0.0540	0.0446	83.9	97.7	90.6	115.8	103.2	0.0378	0.0387	0.0369	0.0371
2034	0.0605	0.0507	0.0504	0.0396	0.0027	0.0682	0.0577	0.0574	0.0456	82.5	94.8	89.1	112.3	100.7	0.0377	0.0385	0.0368	0.0370
2035	0.0626	0.0558	0.0561	0.0474	0.0028	0.0706	0.0633	0.0637	0.0543	88.1	101.0	95.2	119.7	107.4	0.0349	0.0356	0.0340	0.0342
2036	0.0637	0.0562	0.0591	0.0495	0.0031	0.0722	0.0640	0.0672	0.0569	89.6	102.6	96.8	121.6	109.2	0.0338	0.0345	0.0329	0.0331
2037	0.0649	0.0565	0.0622	0.0517	0.0035	0.0739	0.0648	0.0709	0.0596	91.1	104.3	98.4	123.6	111.0	0.0327	0.0334	0.0318	0.0320
2038	0.0661	0.0569	0.0654	0.0540	0.0039	0.0756	0.0656	0.0749	0.0625	92.6	105.9	100.0	125.5	112.8	0.0316	0.0323	0.0308	0.0310
2039	0.0674	0.0573	0.0689	0.0564	0.0043	0.0774	0.0665	0.0790	0.0656	94.2	107.6	101.7	127.5	114.6	0.0306	0.0312	0.0298	0.0300
2040	0.0686	0.0577	0.0725	0.0589	0.0048	0.0793	0.0674	0.0835	0.0688	95.7	109.3	103.4	129.6	116.5	0.0296	0.0302	0.0288	0.0290
2041	0.0699	0.0580	0.0763	0.0615	0.0053	0.0813	0.0684	0.0882	0.0722	97.3	111.1	105.1	131.7	118.4	0.0286	0.0292	0.0279	0.0280
2042	0.0712	0.0584	0.0803	0.0642	0.0059	0.0833	0.0695	0.0931	0.0758	98.9	112.9	106.9	133.8	120.3	0.0277	0.0282	0.0269	0.0271
2043	0.0725	0.0588	0.0845	0.0671	0.0066	0.0855	0.0707	0.0984	0.0796	100.6	114.7	108.6	135.9	122.3	0.0268	0.0273	0.0261	0.0262
2044	0.0739	0.0592	0.0889	0.0701	0.0074	0.0878	0.0719	0.1040	0.0836	102.3	116.5	110.5	138.1	124.3	0.0259	0.0264	0.0252	0.0254
2045	0.0753	0.0596	0.0936	0.0732	0.0082	0.0901	0.0732	0.1100	0.0879	104.0	118.4	112.3	140.3	126.3	0.0250	0.0256	0.0244	0.0245
2046	0.0767	0.0600	0.0985	0.0764	0.0091	0.0927	0.0746	0.1163	0.0924	105.7	120.3	114.2	142.5	128.3	0.0242	0.0247	0.0236	0.0237
2047	0.0781	0.0604	0.1037	0.0798	0.0102	0.0953	0.0762	0.1230	0.0972	107.5	122.2	116.1	144.8	130.4	0.0234	0.0239	0.0228	0.0230
2048	0.0796	0.0608	0.1091	0.0833	0.0113	0.0982	0.0779	0.1301	0.1022	109.3	124.2	118.0	147.1	132.6	0.0227	0.0231	0.0221	0.0222
2049	0.0810	0.0612	0.1149	0.0870	0.0126	0.1011	0.0797	0.1377	0.1076	111.1	126.1	120.0	149.5	134.7	0.0219	0.0224	0.0213	0.0215
2050	0.0826	0.0616	0.1209	0.0909	0.0140	0.1043	0.0817	0.1457	0.1133	112.9	128.2	122.0	151.9	136.9	0.0212	0.0216	0.0207	0.0208
Levelized Costs																		
10 years (2018-2027)	0.0538	0.0498	0.0406	0.0347	0.0043	0.0628	0.0584	0.0486	0.0421	73.3	26.4	79.2	31.2	55.2	0.0429	0.0438	0.0418	0.0420
15 years (2018-2032)	0.0557	0.0514	0.0429	0.0367	0.0036	0.0640	0.0594	0.0502	0.0436	76.9	48.6	83.1	57.6	70.4	0.0415	0.0424	0.0404	0.0407
30 years (2018-2047)	0.0615	0.0540	0.0564	0.0465	0.0043	0.0711	0.0630	0.0656	0.0549	85.1	75.7	92.0	89.7	90.8	0.0364	0.0372	0.0355	0.0357

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: WCMA

	Intrastate																						Wholesale Cross-DRIPE[7]	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures														
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]								
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]					2018 Installation Year	2019 Installation Year
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr					$/kWh	$/kWh
Period:	s	t	u	v	w	x	y=w*DL	z=x*(1+PTF Loss)*(1+WRP)*(1+DL)	aa = (y*%Bid)+z*(1-%Bid)	bb	cc	dd	ee	ff	gg	hh=ff*DL	ii=gg*(1+PTF Loss)*(1+WRP)*(1+DL)	jj = (hh*%Bid)+ii*(1-%Bid)					kk	ll

Period	s	t	u	v	w	x	y	z	aa	bb	cc	dd	ee	ff	gg	hh	ii	jj	kk	ll
2018	0.0196	0.0136	0.0135	0.0089	239.6	-	258.8	-	129.4	-	-	-	-	-	-	-	-	-	0.0075	0.0000
2019	0.0306	0.0212	0.0205	0.0150	126.0	-	136.0	-	68.0	0.0197	0.0137	0.0133	0.0097	151.7	-	163.9	-	81.9	0.0118	0.0074
2020	0.0351	0.0251	0.0262	0.0183	153.4	-	165.7	-	82.8	0.0325	0.0233	0.0243	0.0169	190.0	-	205.3	-	102.6	0.0130	0.0116
2021	0.0370	0.0263	0.0319	0.0216	25.6	-	27.6	-	13.8	0.0364	0.0259	0.0314	0.0212	34.3	-	37.0	-	18.5	0.0132	0.0119
2022	0.0331	0.0228	0.0283	0.0182	17.1	-	18.5	-	9.2	0.0365	0.0251	0.0312	0.0200	25.9	-	28.0	-	14.0	0.0120	0.0120
2023	0.0226	0.0151	0.0176	0.0112	-	16.4	-	19.5	9.7	0.0284	0.0189	0.0222	0.0140	17.3	-	18.6	-	9.3	0.0088	0.0088
2024	0.0183	0.0132	0.0131	0.0098	-	28.7	-	34.1	17.0	0.0236	0.0170	0.0169	0.0126	-	16.7	-	19.8	9.9	0.0057	0.0057
2025	0.0120	0.0087	0.0097	0.0071	-	472.2	-	559.5	279.8	0.0166	0.0120	0.0133	0.0098	-	370.3	-	438.8	219.4	0.0044	0.0044
2026	0.0062	0.0044	0.0054	0.0038	-	558.7	-	662.1	331.0	0.0116	0.0082	0.0100	0.0070	-	505.3	-	598.8	299.4	0.0030	0.0030
2027	0.0038	0.0028	0.0029	0.0021	-	547.1	-	648.4	324.2	0.0065	0.0047	0.0050	0.0035	-	588.3	-	697.2	348.6	0.0018	0.0018
2028	-	-	-	-	-	419.1	-	496.7	248.3	0.0038	0.0026	0.0031	0.0021	-	577.9	-	684.9	342.4	0.0005	0.0005
2029	-	-	-	-	-	275.6	-	326.6	163.3	-	-	-	-	-	445.5	-	527.9	264.0	0.0006	0.0006
2030	-	-	-	-	-	134.2	-	159.0	79.5	-	-	-	-	-	245.5	-	290.9	145.5	0.0006	0.0006
2031	-	-	-	-	-	62.7	-	74.3	37.1	-	-	-	-	-	141.7	-	167.9	84.0	0.0006	0.0006
2032	-	-	-	-	-	18.2	-	21.5	10.8	-	-	-	-	-	66.6	-	79.0	39.5	0.0006	0.0006
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.2	-	19.2	9.6	0.0006	0.0006
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.0006	0.0006
Levelized Costs																				
10 years (2018-2027)	0.0222	0.0156	0.0171	0.0117	58.8	163.3	63.5	193.6	123.5	0.0212	0.0149	0.0168	0.0115	43.3	150.7	46.8	178.6	106.9	0.0082	0.0067
15 years (2018-2032)	0.0153	0.0107	0.0118	0.0081	40.5	173.1	43.7	205.2	119.1	0.0149	0.0104	0.0118	0.0081	29.8	203.3	32.2	240.9	128.8	0.0058	0.0048
30 years (2018-2047)	0.0084	0.0059	0.0065	0.0044	22.3	95.2	24.0	112.8	65.5	0.0082	0.0057	0.0065	0.0044	16.4	112.4	17.7	133.1	71.1	0.0035	0.0029

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)
2. Uncleared capacity value includes reserve margin and uncleared load forecast effect
3. Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.
4. Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%
5. Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%
6. Assumes bid percentage of 50.0%
7. Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE
8. Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: WCMA

	Rest-of-Pool																	
	DRIPE: 2018 vintage measures									DRIPE: 2019 vintage measures								
	Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]			Wholesale Energy DRIPE				Wholesale Capacity DRIPE[2]		Retail Capacity DRIPE[3]		
	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak	Cleared	Uncleared[2]	Cleared[4]	Uncleared[5]	Weighted Avg[6]
Units:	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kWh	$/kWh	$/kWh	$/kWh	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	mm	nn	oo	pp	qq	rr	ss=qq*DL	tt=rr*(1+PTF Loss)*(1+WRP)*(1+DL)	uu = (ss*%Bid)+tt*(1-%Bid)	vv	ww	xx	yy	zz	aaa	bbb=zz*DL	ccc=aaa*(1+PTF Loss)*(1+WRP)*(1+DL)	ddd = (bbb*%Bid)+ccc*(1-%Bid)
2018	0.0192	0.0138	0.0128	0.0084	247.3	-	267.1	-	133.5	-	-	-	-	-	-	-	-	-
2019	0.0298	0.0213	0.0195	0.0140	129.1	-	139.4	-	69.7	0.0192	0.0137	0.0126	0.0090	155.5	-	167.9	-	84.0
2020	0.0340	0.0251	0.0247	0.0171	156.9	-	169.5	-	84.7	0.0315	0.0232	0.0228	0.0159	194.4	-	210.0	-	105.0
2021	0.0355	0.0261	0.0298	0.0200	26.1	-	28.2	-	14.1	0.0349	0.0257	0.0293	0.0197	35.0	-	37.8	-	18.9
2022	0.0317	0.0226	0.0264	0.0170	17.4	-	18.8	-	9.4	0.0349	0.0249	0.0291	0.0187	26.4	-	28.6	-	14.3
2023	0.0260	0.0180	0.0198	0.0125	-	16.7	-	19.8	9.9	0.0327	0.0226	0.0248	0.0157	17.5	-	18.9	-	9.5
2024	0.0210	0.0156	0.0146	0.0107	-	29.1	-	34.5	17.3	0.0271	0.0202	0.0189	0.0138	-	16.9	-	20.0	10.0
2025	0.0142	0.0106	0.0110	0.0080	-	478.1	-	566.6	283.3	0.0195	0.0146	0.0152	0.0110	-	375.0	-	444.3	222.2
2026	0.0075	0.0055	0.0063	0.0044	-	563.4	-	667.6	333.8	0.0139	0.0102	0.0118	0.0082	-	509.5	-	603.8	301.9
2027	0.0046	0.0034	0.0034	0.0024	-	551.7	-	653.8	326.9	0.0077	0.0058	0.0058	0.0040	-	593.2	-	703.0	351.5
2028	0.0000	0.0000	0.0000	0.0000	-	422.6	-	500.8	250.4	0.0045	0.0032	0.0036	0.0024	-	582.8	-	690.6	345.3
2029	0.0000	0.0000	0.0000	0.0000	-	277.9	-	329.4	164.7	-	-	-	-	-	449.2	-	532.3	266.2
2030	-	-	-	-	-	135.3	-	160.3	80.2	-	-	-	-	-	247.6	-	293.4	146.7
2031	-	-	-	-	-	63.2	-	74.9	37.5	-	-	-	-	-	142.9	-	169.3	84.7
2032	-	-	-	-	-	18.3	-	21.7	10.9	-	-	-	-	-	67.2	-	79.6	39.8
2033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16.3	-	19.3	9.7
2034	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2035	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2036	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2037	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2038	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2039	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2040	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2041	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2042	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2043	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2044	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2045	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2046	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2047	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2048	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2049	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2050	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Levelized Costs																		
10 years (2018-2027)	0.0226	0.0164	0.0170	0.0116	60.4	164.9	65.2	195.5	125.3	0.0222	0.0161	0.0170	0.0116	44.3	152.1	47.9	180.3	108.3
15 years (2018-2032)	0.0156	0.0113	0.0117	0.0080	41.6	174.7	44.9	207.1	120.6	0.0156	0.0113	0.0120	0.0081	30.5	205.1	33.0	243.1	130.2
30 years (2018-2047)	0.0086	0.0062	0.0064	0.0044	22.9	96.1	24.7	113.9	66.3	0.0086	0.0062	0.0066	0.0045	16.8	113.4	18.1	134.3	71.9

NOTES:

All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

AESC 2018 Results: Avoided Cost of Electricity (2018 $)

Zone: WCMA

	Wholesale Transmission & Distribution (T&D) Cost	Wholesale Reliability Value[8]					
		Reliability: 2018 vintage measures			Reliability: 2019 vintage measures		
		Cleared	Uncleared	Weighted Avg[5]	Cleared	Uncleared	Weighted Avg[5]
Units:	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr	$/kW-yr
Period:	eee	fff	ggg	hhh = (fff*%Bid)+ggg*(1-%Bid)	iii	jjj	kkk = (iii*%Bid)+jjj*(1-%Bid)
2018	94.0	5.3	16.6	11.0	-	-	-
2019	94.0	2.2	12.7	7.4	2.6	12.7	7.6
2020	94.0	0.9	4.6	2.8	1.2	4.6	2.9
2021	94.0	0.3	7.8	4.0	0.4	7.8	4.1
2022	94.0	0.2	8.0	4.1	0.3	8.0	4.1
2023	94.0	0.1	5.9	3.0	0.2	8.1	4.2
2024	94.0	-	4.6	2.3	0.1	6.2	3.2
2025	94.0	-	8.3	4.1	-	9.0	4.5
2026	94.0	-	7.6	3.8	-	9.0	4.5
2027	94.0	-	6.4	3.2	-	8.4	4.2
2028	94.0	-	6.5	3.3	-	9.0	4.5
2029	94.0	-	4.3	2.1	-	6.9	3.5
2030	94.0	-	1.6	0.8	-	2.9	1.4
2031	94.0	-	1.0	0.5	-	2.3	1.1
2032	94.0	-	0.3	0.1	-	1.1	0.5
2033	94.0	-	-	-	-	0.2	0.1
2034	94.0	-	-	-	-	-	-
2035	94.0	-	-	-	-	-	-
2036	94.0	-	-	-	-	-	-
2037	94.0	-	-	-	-	-	-
2038	94.0	-	-	-	-	-	-
2039	94.0	-	-	-	-	-	-
2040	94.0	-	-	-	-	-	-
2041	94.0	-	-	-	-	-	-
2042	94.0	-	-	-	-	-	-
2043	94.0	-	-	-	-	-	-
2044	94.0	-	-	-	-	-	-
2045	94.0	-	-	-	-	-	-
2046	94.0	-	-	-	-	-	-
2047	94.0	-	-	-	-	-	-
2048	94.0	-	-	-	-	-	-
2049	94.0	-	-	-	-	-	-
2050	94.0	-	-	-	-	-	-
Levelized Costs							
10 years (2018-2027)	94.0	0.9	8.3	4.6	0.5	7.3	3.9
15 years (2018-2032)	94.0	0.6	6.6	3.6	0.3	6.4	3.4
30 years (2018-2047)	94.0	0.4	3.6	2.0	0.2	3.5	1.9

NOTES: All Avoided Costs are in 2018 Dollars

ISO New England 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) * (Wholesale Risk Premium), e.g., f = (a + e) * (1 + 8.0%)

2 Uncleared capacity value includes reserve margin and uncleared load forecast effect

3 Value of avoided capacity costs and capacity DRIPE each year is function of quantity of kW reduction in year, PA bidding strategy that reduction into applicable FCAs, reserve margin, and the uncleared load forecast effect.

4 Proceeds from selling into the FCM also include the ISO New England loss factor of 8.0%

5 Assumes PTF loss factor of 1.6%, ISO New England loss factor of 8.0%, and Wholesale Risk Premium of 8.0%

6 Assumes bid percentage of 50.0%

7 Cross DRIPE = Electric-Gas cross DRIPE + Electric-Gas-Electric cross DRIPE

8 Assumes VOLL of $25.00/kWh

APPENDIX C. DETAILED NATURAL GAS OUTPUTS

The following appendix provides projections of avoided natural gas costs by year, and by end-use. It also includes projections of natural gas supply DRIPE and natural gas cross DRIPE values by year, and by end-use.

Avoided Natural Gas Costs by End-Use

Table 116 through Table 120 include forecasts of avoided natural gas costs by year and end-use for three New England sub-regions: Southern New England (Connecticut, Rhode Island, Massachusetts), Northern New England (New Hampshire, Maine) and Vermont. The avoided cost by end-use is shown two ways: first, as the avoided cost of the gas sent out by the LDC (i.e., the avoided citygate cost), and second, as the avoided cost of the gas sent out by the LDC plus the avoidable distribution cost (i.e., the avoidable retail margin).

The tables show avoided costs for the following end-uses: Residential non-heating, water heating, heating, and all; Commercial & Industrial non-heating, heating, and all; and All Retail End Uses.

- Non-heating columns include values related to year-round end-uses with generally constant gas use throughout the year.
- Heating value columns include values related to heating end-uses in which gas use is high during winter months.
- When determining the cost-effectiveness of a program or measure, users should choose the appropriate column to determine the avoided cost values for each program and/or measure.

As mentioned above, Table 116 through Table 120 contain two types of avoided natural gas costs by end-use and sub-region: the first assumes no avoided retail margin, and the second assumes some amount of avoided retail margins. Program administrators must determine if their LDC has avoidable LDC margins and should pick the appropriate value stream accordingly.

Natural Gas Supply and Cross-Fuel DRIPE

Table 121 through Table 127 include forecasts of natural gas supply and cross-fuel DRIPE by end-use and costing period. This is shown by year and by state, as well as for the whole of New England. Program administrators should identify the natural gas supply and cross-fuel DRIPE data series that are most applicable to the relevant state regulations that govern energy DRIPE. Table 121 through Table 126—the state-level tables—are intrastate values. The values in Table 127 (New England) can be thought of as intrastate values plus rest of pool values. A program administrator can use these values in tandem with avoided costs including or excluding retail margin. A program administrator may also add the natural gas supply and cross-fuel DRIPE values to the avoided natural gas costs in Table 121 through Table 127 for the corresponding year, end-use, and costing period.

Column 1 of Table 121 through Table 127 shows gas supply DRIPE. Program administrators can use the gas supply value by year from this column and apply it to the MMBtu of gas reduction from efficiency programs and measures throughout the lifetime of the program or measure. (As discussed in Chapter 2, gas use reductions by retail gas customers reduce gas demand in producing regions. They therefore reduce the market price for that gas supply. We do not anticipate significant decay in natural gas supply DRIPE values.)

Columns 2 through 9 in Table 121 through Table 127 show gas cross-fuel DRIPE by costing period and load segment. These values are derived using the gas-to-electric cross-fuel heating DRIPE as shown in Table 86. Program administrators can use the gas cross-fuel value by year from these columns and apply them to the MMBtu of gas reduction from the relevant costing period and load segment. (Gas use reduction by retail gas customers reduces both gas production costs and gas basis components in the New England wholesale cost of gas. These costs are incurred by gas-fired electric generators. Therefore, gas programs accrue these benefits as they reduce natural gas prices to electric generators due to natural gas efficiency.)

Avoided Natural Gas Costs by Costing Period

Table 128 and Table 129 show the avoided natural gas cost by year for each of the six costing periods. The values for each costing period are the annual cost per MMBtu for the gas supply resource that is the lowest-cost option to supply that type of load. These values are multiplied by the percentage shares for the representative load shapes (shown in Table 11) to derive the avoided costs by end use that are presented in Table 116 and Table 119. Note, for example, that because the load shape for residential non-heating is 100 percent baseload, the avoided costs for Residential Non-heating in Table 116 and the Baseload values in Table 128 are the same.

The values in tables Table 128 and Table 129 can be used to calculate the avoided natural gas costs for programs that reduce gas use during specific periods during the year. For example, the Baseload avoided cost would be applied to a reduction in gas use (in MMBtu) that is spread equally over all days of the year. The Highest 10 Days avoided cost would be applied to a reduction in gas use that occurs only during the 10 days of highest gas use. The Winter values would be used to calculate the avoided natural gas costs for a program that reduces gas use over the November through March winter season (i.e., more than 90 days, and up to 151 days each year).

Table 116. Avoided cost of gas to retail customers by end-use for Southern New England (SNE) assuming no avoidable retail margin (2018$/MMBtu)

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
2018	4.50	6.34	6.91	6.43	5.27	6.37	5.89	6.18
2019	4.17	6.03	6.60	6.12	4.95	6.06	5.58	5.87
2020	5.08	6.79	7.31	6.87	5.79	6.82	6.37	6.64
2021	5.99	7.71	8.24	7.80	6.71	7.74	7.29	7.56
2022	5.92	7.64	8.16	7.72	6.64	7.66	7.22	7.49
2023	5.94	7.64	8.16	7.73	6.65	7.67	7.22	7.49
2024	6.02	7.72	8.24	7.80	6.73	7.75	7.30	7.57
2025	6.04	7.73	8.25	7.81	6.75	7.76	7.32	7.58
2026	6.12	7.80	8.31	7.88	6.82	7.83	7.39	7.65
2027	6.15	7.82	8.34	7.91	6.85	7.85	7.42	7.68
2028	6.27	7.94	8.45	8.02	6.97	7.97	7.53	7.79
2029	6.38	8.04	8.55	8.12	7.07	8.07	7.63	7.89
2030	6.44	8.09	8.60	8.17	7.13	8.12	7.69	7.95
2031	6.60	8.24	8.75	8.33	7.29	8.27	7.84	8.10
2032	6.61	8.25	8.75	8.33	7.30	8.28	7.85	8.11
2033	6.56	8.19	8.69	8.27	7.24	8.21	7.79	8.04
2034	6.47	8.09	8.59	8.17	7.15	8.12	7.69	7.95
2035	6.50	8.11	8.60	8.19	7.17	8.14	7.71	7.97
2036	6.53	8.14	8.63	8.22	7.21	8.17	7.75	8.00
2037	6.57	8.17	8.66	8.25	7.24	8.20	7.78	8.03
2038	6.61	8.20	8.69	8.28	7.28	8.23	7.82	8.07
2039	6.65	8.23	8.72	8.32	7.32	8.26	7.85	8.10
2040	6.69	8.27	8.75	8.35	7.35	8.30	7.88	8.13
2041	6.73	8.30	8.78	8.38	7.39	8.33	7.92	8.16
2042	6.77	8.33	8.81	8.41	7.43	8.36	7.95	8.20
2043	6.81	8.36	8.84	8.44	7.46	8.39	7.99	8.23
2044	6.85	8.40	8.88	8.48	7.50	8.43	8.02	8.26
2045	6.90	8.43	8.91	8.51	7.54	8.46	8.06	8.30
2046	6.94	8.46	8.94	8.54	7.58	8.49	8.09	8.33
2047	6.98	8.50	8.97	8.57	7.61	8.52	8.13	8.37
2048	7.02	8.53	9.00	8.61	7.65	8.56	8.16	8.40
2049	7.06	8.56	9.03	8.64	7.69	8.59	8.20	8.43
2050	7.10	8.60	9.06	8.67	7.73	8.62	8.23	8.47
Levelized (2018-2027)	5.57	7.30	7.83	7.39	6.30	7.33	6.88	7.15
Levelized (2018-2032)	5.85	7.55	8.08	7.64	6.56	7.58	7.14	7.40
Levelized (2018-2047)	6.23	7.88	8.38	7.96	6.92	7.91	7.47	7.73

(a) Real (constant $) riskless annual rate of return: 1.34%

(b) Values from 2036-2050 extrapolated from Compound Annual Growth Rate (2026-2035)

Notes: Real (constant $) riskless annual rate of return: 1.34%; values from 2036–2050 extrapolated from Compound Annual Growth Rate (2026–2035).

These notes apply to the following tables in this section.

Table 117. Avoided cost of gas to retail customers by end-use for Southern New England (SNE) assuming some avoidable retail margin (2018$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
2018	4.83	6.68	7.99	7.38	5.69	7.13	6.50	6.94
2019	4.50	6.36	7.69	7.07	5.37	6.82	6.19	6.63
2020	5.41	7.13	8.40	7.82	6.22	7.57	6.98	7.40
2021	6.33	8.05	9.33	8.75	7.14	8.50	7.90	8.32
2022	6.26	7.97	9.25	8.67	7.06	8.42	7.83	8.25
2023	6.27	7.98	9.25	8.67	7.08	8.42	7.84	8.25
2024	6.36	8.05	9.33	8.75	7.16	8.50	7.91	8.33
2025	6.38	8.06	9.34	8.76	7.17	8.51	7.93	8.34
2026	6.45	8.13	9.40	8.83	7.25	8.58	8.00	8.41
2027	6.49	8.16	9.43	8.85	7.28	8.61	8.03	8.44
2028	6.61	8.27	9.54	8.97	7.40	8.72	8.14	8.56
2029	6.71	8.37	9.64	9.07	7.50	8.82	8.24	8.65
2030	6.77	8.42	9.69	9.12	7.55	8.87	8.30	8.71
2031	6.93	8.58	9.84	9.27	7.71	9.03	8.45	8.86
2032	6.95	8.58	9.84	9.28	7.72	9.03	8.46	8.87
2033	6.89	8.52	9.78	9.22	7.66	8.97	8.40	8.81
2034	6.80	8.42	9.68	9.12	7.57	8.87	8.30	8.71
2035	6.83	8.44	9.69	9.14	7.60	8.89	8.32	8.73
2036	6.87	8.47	9.72	9.17	7.63	8.92	8.36	8.76
2037	6.91	8.51	9.75	9.20	7.67	8.95	8.39	8.79
2038	6.95	8.54	9.78	9.23	7.70	8.99	8.43	8.83
2039	6.99	8.57	9.81	9.26	7.74	9.02	8.46	8.86
2040	7.03	8.60	9.84	9.29	7.78	9.05	8.49	8.89
2041	7.07	8.63	9.87	9.33	7.81	9.08	8.53	8.93
2042	7.11	8.67	9.90	9.36	7.85	9.11	8.56	8.96
2043	7.15	8.70	9.93	9.39	7.89	9.15	8.60	8.99
2044	7.19	8.73	9.96	9.42	7.93	9.18	8.63	9.03
2045	7.23	8.76	9.99	9.45	7.96	9.21	8.67	9.06
2046	7.27	8.80	10.02	9.49	8.00	9.24	8.70	9.09
2047	7.31	8.83	10.05	9.52	8.04	9.28	8.73	9.13
2048	7.35	8.86	10.09	9.55	8.08	9.31	8.77	9.16
2049	7.39	8.90	10.12	9.58	8.11	9.34	8.81	9.19
2050	7.44	8.93	10.15	9.62	8.15	9.38	8.84	9.23
Levelized (2018-2027)	5.91	7.64	8.92	8.33	6.72	8.09	7.49	7.91
Levelized (2018-2032)	6.18	7.89	9.17	8.58	6.99	8.34	7.75	8.17
Levelized (2018-2047)	6.56	8.21	9.47	8.91	7.34	8.66	8.08	8.50

Table 118. Avoided cost of gas to retail customers by end-use for Northern New England (NNE) assuming no avoidable retail margin (2018$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
2018	4.28	6.09	6.60	6.15	5.05	6.12	5.65	5.92
2019	3.96	5.79	6.30	5.85	4.73	5.82	5.35	5.61
2020	4.87	6.54	7.01	6.59	5.58	6.57	6.13	6.38
2021	5.78	7.48	7.95	7.53	6.50	7.51	7.07	7.32
2022	5.72	7.41	7.88	7.46	6.43	7.43	7.00	7.24
2023	5.74	7.42	7.89	7.47	6.45	7.45	7.01	7.26
2024	5.82	7.50	7.98	7.56	6.54	7.53	7.10	7.34
2025	5.85	7.52	7.99	7.58	6.56	7.55	7.12	7.36
2026	5.92	7.60	8.07	7.65	6.63	7.63	7.19	7.44
2027	5.96	7.63	8.10	7.69	6.67	7.66	7.23	7.47
2028	6.08	7.75	8.22	7.81	6.79	7.78	7.35	7.59
2029	6.19	7.86	8.33	7.91	6.90	7.89	7.45	7.70
2030	6.25	7.92	8.39	7.97	6.96	7.95	7.51	7.76
2031	6.41	8.08	8.55	8.13	7.12	8.11	7.68	7.92
2032	6.43	8.09	8.56	8.15	7.14	8.12	7.69	7.93
2033	6.38	8.03	8.50	8.09	7.08	8.06	7.63	7.88
2034	6.29	7.94	8.40	7.99	6.99	7.97	7.54	7.78
2035	6.32	7.97	8.43	8.02	7.02	7.99	7.57	7.81
2036	6.36	8.00	8.46	8.06	7.06	8.03	7.61	7.85
2037	6.40	8.04	8.50	8.09	7.10	8.07	7.65	7.89
2038	6.45	8.08	8.54	8.13	7.14	8.11	7.69	7.92
2039	6.49	8.12	8.58	8.17	7.18	8.15	7.72	7.96
2040	6.53	8.16	8.61	8.21	7.22	8.18	7.76	8.00
2041	6.57	8.19	8.65	8.25	7.26	8.22	7.80	8.04
2042	6.61	8.23	8.69	8.29	7.30	8.26	7.84	8.08
2043	6.66	8.27	8.73	8.33	7.35	8.30	7.88	8.12
2044	6.70	8.31	8.77	8.36	7.39	8.34	7.92	8.16
2045	6.75	8.35	8.80	8.40	7.43	8.38	7.96	8.20
2046	6.79	8.39	8.84	8.44	7.47	8.42	8.01	8.24
2047	6.83	8.43	8.88	8.48	7.51	8.46	8.05	8.28
2048	6.88	8.47	8.92	8.52	7.56	8.50	8.09	8.32
2049	6.92	8.51	8.96	8.56	7.60	8.54	8.13	8.36
2050	6.97	8.55	9.00	8.60	7.64	8.58	8.17	8.40
Levelized (2018-2027)	5.37	7.08	7.56	7.13	6.09	7.11	6.66	6.91
Levelized (2018-2032)	5.65	7.34	7.82	7.40	6.37	7.37	6.93	7.18
Levelized (2018-2047)	6.05	7.71	8.18	7.77	6.75	7.74	7.31	7.55

Table 119. Avoided cost of gas to retail customers by end-use for Northern New England (NNE) assuming some avoidable retail margin (2018$/MMBtu)

	RESIDENTIAL				COMMERCIAL & INDUSTRIAL			ALL RETAIL END USES
Year	Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
2018	4.59	6.40	7.60	7.02	5.33	6.62	6.06	6.38
2019	4.27	6.10	7.31	6.72	5.02	6.32	5.75	6.08
2020	5.18	6.85	8.01	7.47	5.86	7.07	6.54	6.85
2021	6.09	7.79	8.96	8.41	6.78	8.01	7.47	7.78
2022	6.03	7.72	8.89	8.34	6.72	7.94	7.40	7.71
2023	6.04	7.73	8.90	8.35	6.73	7.95	7.42	7.72
2024	6.13	7.81	8.98	8.43	6.82	8.03	7.50	7.81
2025	6.15	7.83	9.00	8.45	6.84	8.05	7.52	7.83
2026	6.23	7.91	9.07	8.53	6.92	8.13	7.60	7.90
2027	6.27	7.94	9.11	8.56	6.95	8.16	7.63	7.94
2028	6.39	8.06	9.23	8.68	7.08	8.28	7.76	8.06
2029	6.50	8.17	9.33	8.79	7.18	8.39	7.86	8.17
2030	6.56	8.23	9.39	8.85	7.24	8.45	7.92	8.22
2031	6.72	8.39	9.55	9.01	7.40	8.61	8.08	8.39
2032	6.74	8.40	9.56	9.02	7.42	8.62	8.10	8.40
2033	6.69	8.34	9.50	8.96	7.36	8.56	8.04	8.34
2034	6.60	8.25	9.41	8.87	7.28	8.47	7.95	8.25
2035	6.63	8.27	9.43	8.89	7.30	8.50	7.98	8.28
2036	6.67	8.31	9.47	8.93	7.34	8.53	8.01	8.31
2037	6.71	8.35	9.51	8.97	7.38	8.57	8.05	8.35
2038	6.75	8.39	9.54	9.01	7.42	8.61	8.09	8.39
2039	6.80	8.43	9.58	9.05	7.46	8.65	8.13	8.43
2040	6.84	8.47	9.62	9.08	7.50	8.69	8.17	8.47
2041	6.88	8.50	9.66	9.12	7.55	8.73	8.21	8.51
2042	6.92	8.54	9.69	9.16	7.59	8.76	8.25	8.55
2043	6.97	8.58	9.73	9.20	7.63	8.80	8.29	8.58
2044	7.01	8.62	9.77	9.24	7.67	8.84	8.33	8.62
2045	7.05	8.66	9.81	9.28	7.71	8.88	8.37	8.66
2046	7.10	8.70	9.85	9.32	7.75	8.92	8.41	8.70
2047	7.14	8.74	9.88	9.36	7.80	8.96	8.45	8.74
2048	7.19	8.78	9.92	9.40	7.84	9.00	8.49	8.78
2049	7.23	8.82	9.96	9.44	7.88	9.04	8.53	8.82
2050	7.27	8.86	10.00	9.48	7.92	9.08	8.57	8.87
Levelized (2018-2027)	5.68	7.39	8.56	8.01	6.37	7.61	7.07	7.38
Levelized (2018-2032)	5.96	7.65	8.83	8.28	6.65	7.88	7.34	7.65
Levelized (2018-2047)	6.36	8.02	9.18	8.64	7.04	8.24	7.72	8.02

Table 120. Avoided cost of gas to retail customers by end-use for Vermont assuming no avoidable retail margin (2018$/MMBtu)

Year	RESIDENTIAL			
	Design day	Peak Days	Remaining winter	Shoulder / summer
	1	9	141	214
2018	559.96	19.00	3.46	3.05
2019	559.65	19.00	3.15	2.74
2020	560.57	20.96	4.07	3.66
2021	561.48	22.91	4.98	4.57
2022	561.43	24.86	4.93	4.52
2023	561.46	26.81	4.96	4.55
2024	561.56	27.24	5.06	4.65
2025	561.59	27.98	5.09	4.68
2026	561.68	28.63	5.18	4.77
2027	561.73	28.98	5.23	4.82
2028	561.86	29.12	5.36	4.95
2029	561.97	29.40	5.47	5.06
2030	562.05	30.13	5.54	5.14
2031	562.22	30.82	5.71	5.31
2032	562.24	31.60	5.74	5.33
2033	562.20	31.64	5.70	5.29
2034	562.12	32.21	5.62	5.21
2035	562.16	32.42	5.66	5.25
2036	562.21	32.83	5.71	5.30
2037	562.25	33.24	5.76	5.35
2038	562.30	33.66	5.81	5.40
2039	562.35	34.08	5.86	5.45
2040	562.40	34.50	5.91	5.51
2041	562.45	34.94	5.97	5.56
2042	562.49	35.37	6.02	5.61
2043	562.54	35.82	6.07	5.67
2044	562.59	36.26	6.13	5.72
2045	562.64	36.72	6.18	5.78
2046	562.69	37.18	6.24	5.83
2047	562.73	37.64	6.29	5.89
2048	562.78	38.11	6.35	5.94
2049	562.83	38.59	6.40	6.00
2050	562.88	39.07	6.46	6.06
Levelized (2018-2027)	561.09	24.50	4.59	4.18
Levelized (2018-2032)	561.39	26.27	4.89	4.48
Levelized (2018-2047)	561.84	29.96	5.35	4.94

Table 121. Gas supply DRIPE and gas cross DRIPE—Connecticut (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	C&I Heating	C&I All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.01	0.52	0.52	0.97	0.81	0.52	0.97	0.77	0.79
2019	0.01	0.82	0.82	1.52	1.28	0.82	1.52	1.21	1.25
2020	0.02	0.90	0.90	1.67	1.40	0.90	1.67	1.33	1.37
2021	0.02	0.89	0.89	1.64	1.38	0.89	1.64	1.31	1.35
2022	0.02	0.80	0.80	1.49	1.25	0.80	1.49	1.19	1.22
2023	0.02	0.58	0.58	1.07	0.90	0.58	1.07	0.86	0.88
2024	0.02	0.37	0.37	0.67	0.57	0.37	0.67	0.54	0.55
2025	0.02	0.28	0.28	0.50	0.42	0.28	0.50	0.40	0.41
2026	0.02	0.19	0.19	0.33	0.28	0.19	0.33	0.27	0.28
2027	0.02	0.10	0.10	0.16	0.14	0.10	0.16	0.13	0.14
2028	0.02	0.02	0.02	0.01	0.01	0.02	0.01	0.01	0.01
2029	0.02	0.02	0.02	0.01	0.01	0.02	0.01	0.01	0.01
2030	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.02	0.55	0.55	1.02	0.86	0.55	1.02	0.82	0.84
Levelized (2018-2032)	0.02	0.38	0.38	0.70	0.59	0.38	0.70	0.56	0.58
Levelized (2018-2047)	0.02	0.21	0.21	0.39	0.32	0.21	0.39	0.31	0.32

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 122. Gas supply DRIPE and gas cross DRIPE—Massachusetts (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.01	1.22	1.22	2.27	1.90	1.22	2.27	1.81	1.86
2019	0.02	1.93	1.93	3.58	3.00	1.93	3.58	2.86	2.94
2020	0.03	2.13	2.13	3.95	3.31	2.13	3.95	3.15	3.24
2021	0.04	2.15	2.15	3.97	3.33	2.15	3.97	3.17	3.26
2022	0.04	1.94	1.94	3.59	3.01	1.94	3.59	2.87	2.95
2023	0.04	1.17	1.17	2.15	1.81	1.17	2.15	1.72	1.77
2024	0.04	0.75	0.75	1.36	1.15	0.75	1.36	1.09	1.12
2025	0.04	0.55	0.55	0.98	0.83	0.55	0.98	0.79	0.81
2026	0.04	0.37	0.37	0.63	0.54	0.37	0.63	0.52	0.53
2027	0.04	0.20	0.20	0.32	0.28	0.20	0.32	0.27	0.27
2028	0.04	0.04	0.04	0.02	0.03	0.04	0.02	0.03	0.03
2029	0.04	0.04	0.04	0.02	0.03	0.04	0.02	0.03	0.03
2030	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.03	1.26	1.26	2.32	1.95	1.26	2.32	1.86	1.91
Levelized (2018-2032)	0.04	0.87	0.87	1.60	1.35	0.87	1.60	1.28	1.32
Levelized (2018-2047)	0.04	0.48	0.48	0.88	0.74	0.48	0.88	0.71	0.72

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 123. Gas supply DRIPE and gas cross DRIPE—Maine (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.00	0.24	0.24	0.44	0.37	0.24	0.44	0.35	0.36
2019	0.00	0.38	0.38	0.70	0.59	0.38	0.70	0.56	0.58
2020	0.00	0.42	0.42	0.77	0.65	0.42	0.77	0.62	0.63
2021	0.00	0.42	0.42	0.78	0.65	0.42	0.78	0.62	0.64
2022	0.00	0.38	0.38	0.70	0.59	0.38	0.70	0.56	0.58
2023	0.00	0.28	0.28	0.51	0.43	0.28	0.51	0.41	0.42
2024	0.00	0.18	0.18	0.32	0.27	0.18	0.32	0.26	0.27
2025	0.00	0.13	0.13	0.24	0.20	0.13	0.24	0.19	0.20
2026	0.00	0.09	0.09	0.16	0.14	0.09	0.16	0.13	0.13
2027	0.01	0.05	0.05	0.08	0.07	0.05	0.08	0.07	0.07
2028	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
2029	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
2030	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.00	0.26	0.26	0.48	0.40	0.26	0.48	0.38	0.39
Levelized (2018-2032)	0.00	0.18	0.18	0.33	0.28	0.18	0.33	0.26	0.27
Levelized (2018-2047)	0.01	0.10	0.10	0.18	0.15	0.10	0.18	0.15	0.15

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 124. Gas supply DRIPE and gas cross DRIPE—New Hampshire (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.00	0.25	0.25	0.47	0.39	0.25	0.47	0.37	0.38
2019	0.00	0.39	0.39	0.74	0.62	0.39	0.74	0.59	0.60
2020	0.00	0.44	0.44	0.81	0.68	0.44	0.81	0.65	0.67
2021	0.01	0.44	0.44	0.82	0.69	0.44	0.82	0.65	0.67
2022	0.01	0.40	0.40	0.74	0.62	0.40	0.74	0.59	0.61
2023	0.01	0.29	0.29	0.53	0.45	0.29	0.53	0.43	0.44
2024	0.01	0.18	0.18	0.33	0.28	0.18	0.33	0.26	0.27
2025	0.01	0.14	0.14	0.25	0.21	0.14	0.25	0.20	0.21
2026	0.01	0.09	0.09	0.16	0.14	0.09	0.16	0.13	0.13
2027	0.01	0.05	0.05	0.08	0.07	0.05	0.08	0.07	0.07
2028	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
2029	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
2030	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.01	0.27	0.27	0.50	0.42	0.27	0.50	0.40	0.41
Levelized (2018-2032)	0.01	0.19	0.19	0.34	0.29	0.19	0.34	0.28	0.28
Levelized (2018-2047)	0.01	0.10	0.10	0.19	0.16	0.10	0.19	0.15	0.16

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 125. Gas supply DRIPE and gas cross DRIPE—Rhode Island (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.00	0.18	0.18	0.32	0.27	0.18	0.32	0.26	0.27
2019	0.00	0.28	0.28	0.51	0.43	0.28	0.51	0.41	0.42
2020	0.01	0.30	0.30	0.56	0.47	0.30	0.56	0.45	0.46
2021	0.01	0.30	0.30	0.55	0.46	0.30	0.55	0.44	0.45
2022	0.01	0.27	0.27	0.50	0.42	0.27	0.50	0.40	0.41
2023	0.01	0.20	0.20	0.36	0.30	0.20	0.36	0.29	0.30
2024	0.01	0.13	0.13	0.23	0.20	0.13	0.23	0.19	0.19
2025	0.01	0.10	0.10	0.17	0.15	0.10	0.17	0.14	0.14
2026	0.01	0.07	0.07	0.11	0.10	0.07	0.11	0.09	0.09
2027	0.01	0.04	0.04	0.06	0.05	0.04	0.06	0.05	0.05
2028	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
2029	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00
2030	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.01	0.19	0.19	0.34	0.29	0.19	0.34	0.28	0.28
Levelized (2018-2032)	0.01	0.13	0.13	0.24	0.20	0.13	0.24	0.19	0.20
Levelized (2018-2047)	0.01	0.07	0.07	0.13	0.11	0.07	0.13	0.10	0.11

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 126. Gas supply DRIPE and gas cross DRIPE—Vermont (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.00	0.05	0.05	0.09	0.08	0.05	0.09	0.07	0.07
2019	0.00	0.08	0.08	0.15	0.13	0.08	0.15	0.12	0.12
2020	0.00	0.09	0.09	0.16	0.14	0.09	0.16	0.13	0.13
2021	0.00	0.09	0.09	0.16	0.14	0.09	0.16	0.13	0.13
2022	0.00	0.08	0.08	0.15	0.13	0.08	0.15	0.12	0.12
2023	0.00	0.06	0.06	0.11	0.09	0.06	0.11	0.09	0.09
2024	0.00	0.04	0.04	0.07	0.06	0.04	0.07	0.06	0.06
2025	0.00	0.03	0.03	0.05	0.04	0.03	0.05	0.04	0.04
2026	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03
2027	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02
2028	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2029	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.00	0.06	0.06	0.10	0.08	0.06	0.10	0.08	0.08
Levelized (2018-2032)	0.00	0.04	0.04	0.07	0.06	0.04	0.07	0.06	0.06
Levelized (2018-2047)	0.00	0.02	0.02	0.04	0.03	0.02	0.04	0.03	0.03

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 127. Gas supply DRIPE and gas cross DRIPE—New England (2018$/MMBtu)

Year	Gas Supply DRIPE (applicable to reductions in every end-use)	Gas Cross DRIPE (applicable to reductions by end-use): RESIDENTIAL Non Heating	RESIDENTIAL Hot Water	RESIDENTIAL Heating	RESIDENTIAL All	COMMERCIAL & INDUSTRIAL Non Heating	COMMERCIAL & INDUSTRIAL Heating	COMMERCIAL & INDUSTRIAL All	ALL RETAIL END USES
	1	2	3	4	5	6	7	8	9
2018	0.03	2.46	2.46	4.58	3.84	2.46	4.58	3.65	3.75
2019	0.04	3.88	3.88	7.21	6.04	3.88	7.21	5.75	5.91
2020	0.07	4.27	4.27	7.94	6.66	4.27	7.94	6.34	6.51
2021	0.08	4.29	4.29	7.94	6.66	4.29	7.94	6.34	6.51
2022	0.08	3.88	3.88	7.18	6.03	3.88	7.18	5.74	5.89
2023	0.08	2.58	2.58	4.75	3.99	2.58	4.75	3.80	3.90
2024	0.08	1.65	1.65	2.99	2.52	1.65	2.99	2.40	2.47
2025	0.08	1.23	1.23	2.19	1.85	1.23	2.19	1.77	1.82
2026	0.08	0.83	0.83	1.43	1.22	0.83	1.43	1.17	1.20
2027	0.08	0.45	0.45	0.72	0.63	0.45	0.72	0.60	0.61
2028	0.09	0.10	0.10	0.04	0.06	0.10	0.04	0.07	0.06
2029	0.09	0.10	0.10	0.04	0.06	0.10	0.04	0.07	0.06
2030	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2031	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2032	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2049	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2050	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized (2018-2027)	0.07	2.59	2.59	4.77	4.01	2.59	4.77	3.82	3.92
Levelized (2018-2032)	0.08	1.80	1.80	3.29	2.77	1.80	3.29	2.64	2.71
Levelized (2018-2047)	0.08	0.99	0.99	1.81	1.52	0.99	1.81	1.45	1.49

Notes: Real (constant $) riskless annual rate of return: 1.34%.
Values for years 2018 through 2030 from AESC 2018 modeling.
Values for years from 2031 onward held at 2030 levels
The same baseline values are used for Residential and C&I. Class level averages (columns 5 and 8) are calculated used class-level consumption weights by use case.

Table 128. Avoided natural gas costs by costing period – Southern New England (2018$/MMBtu)

Year	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	365	273	151	90	30	10
2018	$4.50	$5.56	$7.60	$11.19	$17.01	$4.91
2019	$4.17	$5.22	$7.26	$11.11	$16.86	$4.62
2020	$5.08	$6.12	$8.10	$10.80	$16.38	$5.50
2021	$5.99	$7.03	$9.02	$11.74	$17.74	$6.38
2022	$5.92	$6.95	$8.92	$11.67	$17.61	$6.33
2023	$5.94	$6.96	$8.91	$11.68	$17.60	$6.36
2024	$6.02	$7.04	$8.97	$11.77	$17.70	$6.45
2025	$6.04	$7.05	$8.97	$11.79	$17.70	$6.48
2026	$6.12	$7.11	$9.02	$11.86	$17.79	$6.57
2027	$6.15	$7.14	$9.03	$11.90	$17.81	$6.61
2028	$6.27	$7.25	$9.13	$12.02	$17.97	$6.74
2029	$6.38	$7.35	$9.21	$12.12	$18.10	$6.85
2030	$6.44	$7.40	$9.25	$12.18	$18.17	$6.92
2031	$6.60	$7.55	$9.39	$12.34	$18.38	$7.08
2032	$6.61	$7.56	$9.39	$12.36	$18.38	$7.10
2033	$6.56	$7.50	$9.31	$12.30	$18.27	$7.06
2034	$6.47	$7.40	$9.19	$12.20	$18.11	$6.99
2035	$6.50	$7.42	$9.20	$12.23	$18.13	$7.03

Table 129. Avoided natural gas costs by costing period – Northern New England (2018$/MMBtu)

Year	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	365	273	151	90	30	10
2018	$4.28	$5.25	$7.06	$10.67	$14.56	$18.08
2019	$3.96	$4.91	$6.74	$10.61	$14.47	$17.97
2020	$4.87	$5.81	$7.58	$10.33	$14.05	$17.42
2021	$5.78	$6.73	$8.51	$11.28	$15.46	$19.25
2022	$5.72	$6.66	$8.42	$11.23	$15.39	$19.15
2023	$5.74	$6.67	$8.42	$11.26	$15.43	$19.20
2024	$5.82	$6.75	$8.49	$11.36	$15.58	$19.40
2025	$5.85	$6.76	$8.49	$11.40	$15.63	$19.46
2026	$5.92	$6.83	$8.55	$11.49	$15.77	$19.64
2027	$5.96	$6.86	$8.57	$11.54	$15.84	$19.73
2028	$6.08	$6.98	$8.68	$11.68	$16.04	$20.00
2029	$6.19	$7.08	$8.77	$11.80	$16.22	$20.23
2030	$6.25	$7.14	$8.81	$11.87	$16.33	$20.37
2031	$6.41	$7.29	$8.96	$12.05	$16.59	$20.70
2032	$6.43	$7.30	$8.96	$12.07	$16.63	$20.75
2033	$6.38	$7.25	$8.89	$12.03	$16.56	$20.67
2034	$6.29	$7.15	$8.78	$11.95	$16.45	$20.52
2035	$6.32	$7.18	$8.80	$11.99	$16.51	$20.59

APPENDIX D. DETAILED OIL AND OTHER FUEL OUTPUTS

This appendix provides avoided costs for fuel oil and other fuels by year, and by sector. As in the above appendices, annual data is provided alongside levelized costs over three different costing periods: 10-year (2018–2027), 15-year (2018–2032), and 30-year periods (2018–2047). This Appendix also details emission values for SO_2, NO_X, CO_2, and CO_2 priced at $100 per ton. Note that these costs and emission values are assumed to be the same for all states and reporting regions in New England.

Table 130 provides the avoided costs for two types of fuel:

- Fuel Oils, which includes distillate fuel oil, residual fuel oil, and a weighted average, and
- Other Fuels, which includes cord wood, wood pellets, kerosene, and propane.

Avoided costs for these fuel oils and other fuels are shown by year and by applicable sector (residential, commercial, and/or industrial). Table 131 provides the fuel oil emission values for SO_2, NO_X, CO_2, and CO_2 priced at $100 per ton. The emission values are shown by year and by sector.

Table 130. Avoided costs of petroleum fuels and other fuels by sector

Year	Fuel Oils							Other Fuels				
	Residential	Commercial			Industrial			Residential				Industrial
	Distillate Fuel Oil $/MMBtu	Distillate Fuel Oil $/MMBtu	Residual Fuel Oil $/MMBtu	Weighted Average $/MMBtu	Distillate Fuel Oil $/MMBtu	Residual Fuel Oil $/MMBtu	Weighted Average $/MMBtu	Cord Wood $/MMBtu	Wood Pellets $/MMBtu	Kerosene $/MMBtu	Propane $/MMBtu	Kerosene $/MMBtu
	2018$	2018$	2018$	2018$	2018$	2018$	2018$	2018$	2018$	2018$	2018$	2018$
2018	$17.30	$14.16	$10.69	$14.04	$14.44	$10.93	$14.16	$10.46	$16.86	$15.52	$26.98	$14.63
2019	$16.26	$13.36	$10.63	$13.27	$13.66	$10.97	$13.44	$9.83	$15.85	$14.58	$24.12	$13.84
2020	$17.71	$14.59	$12.09	$14.51	$14.95	$12.57	$14.76	$10.71	$17.26	$15.88	$25.62	$15.15
2021	$19.37	$15.96	$13.62	$15.88	$16.37	$14.24	$16.20	$11.72	$18.88	$17.37	$27.57	$16.59
2022	$20.95	$17.38	$15.05	$17.30	$17.87	$15.83	$17.71	$12.67	$20.41	$18.78	$30.08	$18.11
2023	$22.91	$19.03	$16.74	$18.95	$19.58	$17.61	$19.42	$13.85	$22.33	$20.54	$32.86	$19.84
2024	$23.23	$19.30	$17.13	$19.22	$19.86	$18.02	$19.72	$14.05	$22.64	$20.83	$33.01	$20.13
2025	$23.71	$19.79	$17.70	$19.72	$20.40	$18.61	$20.26	$14.34	$23.11	$21.26	$32.94	$20.68
2026	$24.08	$20.11	$18.16	$20.05	$20.74	$19.10	$20.61	$14.56	$23.47	$21.59	$33.00	$21.02
2027	$24.28	$20.33	$18.34	$20.27	$20.98	$19.29	$20.85	$14.68	$23.66	$21.77	$33.31	$21.26
2028	$24.32	$20.39	$18.42	$20.33	$21.05	$19.37	$20.92	$14.71	$23.70	$21.81	$33.40	$21.33
2029	$24.54	$20.63	$18.77	$20.57	$21.31	$19.74	$21.19	$14.84	$23.91	$22.00	$33.44	$21.60
2030	$25.00	$21.05	$19.23	$20.99	$21.76	$20.22	$21.64	$15.12	$24.36	$22.42	$33.70	$22.05
2031	$25.41	$21.40	$19.69	$21.34	$22.13	$20.71	$22.02	$15.37	$24.76	$22.78	$34.37	$22.43
2032	$25.90	$21.81	$20.20	$21.76	$22.56	$21.25	$22.46	$15.66	$25.25	$23.23	$34.87	$22.86
2033	$25.82	$21.80	$20.18	$21.74	$22.56	$21.23	$22.45	$15.61	$25.16	$23.15	$34.97	$22.86
2034	$26.13	$22.07	$20.55	$22.02	$22.84	$21.62	$22.75	$15.80	$25.47	$23.43	$35.34	$23.15
2035	$26.35	$22.24	$20.74	$22.19	$23.02	$21.82	$22.92	$15.93	$25.68	$23.63	$35.51	$23.33
2036	$26.88	$22.69	$21.34	$22.65	$23.50	$22.44	$23.41	$16.25	$26.19	$24.10	$36.04	$23.81
2037	$26.95	$22.74	$21.45	$22.69	$23.54	$22.56	$23.46	$16.30	$26.27	$24.17	$36.28	$23.86
2038	$27.12	$22.84	$21.59	$22.80	$23.64	$22.71	$23.57	$16.40	$26.43	$24.32	$36.76	$23.96
2039	$27.49	$23.14	$21.88	$23.10	$23.96	$23.01	$23.88	$16.62	$26.79	$24.65	$37.45	$24.28
2040	$27.69	$23.27	$22.12	$23.23	$24.09	$23.26	$24.02	$16.74	$26.99	$24.83	$37.70	$24.41
2041	$27.73	$23.32	$22.36	$23.29	$24.14	$23.52	$24.09	$16.77	$27.03	$24.87	$38.12	$24.46
2042	$27.79	$23.30	$22.30	$23.27	$24.11	$23.46	$24.05	$16.80	$27.08	$24.92	$38.33	$24.43
2043	$27.85	$23.31	$22.36	$23.28	$24.11	$23.52	$24.07	$16.84	$27.14	$24.97	$38.65	$24.44
2044	$27.95	$23.36	$22.47	$23.33	$24.16	$23.63	$24.11	$16.90	$27.23	$25.06	$38.91	$24.48
2045	$28.04	$23.45	$22.60	$23.43	$24.26	$23.77	$24.22	$16.95	$27.32	$25.14	$39.04	$24.59
2046	$28.21	$23.61	$22.80	$23.59	$24.43	$23.99	$24.40	$17.06	$27.49	$25.29	$39.33	$24.76
2047	$28.55	$23.91	$23.10	$23.88	$24.75	$24.30	$24.71	$17.27	$27.83	$25.60	$39.65	$25.08
2048	$28.57	$23.93	$23.15	$23.90	$24.76	$24.35	$24.73	$17.28	$27.85	$25.62	$40.01	$25.10
2049	$28.76	$24.10	$23.37	$24.08	$24.95	$24.58	$24.92	$17.39	$28.03	$25.79	$40.20	$25.29
2050	$29.04	$24.34	$23.66	$24.32	$25.20	$24.89	$25.18	$17.56	$28.30	$26.04	$40.55	$25.54
Levelized Costs												
2018-2027	$20.87	$17.31	$14.91	$17.23	$17.79	$15.60	$17.61	$12.62	$20.34	$18.72	$29.83	$18.03
2018-2032	$22.17	$18.47	$16.26	$18.40	$19.02	$17.05	$18.86	$13.40	$21.60	$19.88	$31.11	$19.28
2018-2047	$24.49	$20.50	$18.76	$20.44	$21.16	$19.70	$21.04	$14.81	$23.86	$21.96	$33.94	$21.45
Note:												
Real Discount rate:		1.34%										

Table 131. Fuel oil emission values (2018$/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
2018	$ 0.00	$ 5.43	$ 0.49	$ 8.05	$ 0.00	$ 7.20	$ 0.49	$ 8.05	$ 0.00	$ 7.20	$ 0.49	$ 8.05
2019	$ 0.00	$ 5.43	$ 0.71	$ 8.05	$ 0.00	$ 7.20	$ 0.71	$ 8.05	$ 0.00	$ 7.20	$ 0.71	$ 8.05
2020	$ 0.00	$ 5.43	$ 0.93	$ 8.05	$ 0.00	$ 7.20	$ 0.93	$ 8.05	$ 0.00	$ 7.20	$ 0.93	$ 8.05
2021	$ 0.00	$ 5.43	$ 0.99	$ 8.05	$ 0.00	$ 7.20	$ 0.99	$ 8.05	$ 0.00	$ 7.20	$ 0.99	$ 8.05
2022	$ 0.00	$ 5.43	$ 1.05	$ 8.05	$ 0.00	$ 7.20	$ 1.05	$ 8.05	$ 0.00	$ 7.20	$ 1.05	$ 8.05
2023	$ 0.00	$ 5.43	$ 1.11	$ 8.05	$ 0.00	$ 7.20	$ 1.11	$ 8.05	$ 0.00	$ 7.20	$ 1.11	$ 8.05
2024	$ 0.00	$ 5.43	$ 1.20	$ 8.05	$ 0.00	$ 7.20	$ 1.20	$ 8.05	$ 0.00	$ 7.20	$ 1.20	$ 8.05
2025	$ 0.00	$ 5.43	$ 1.29	$ 8.05	$ 0.00	$ 7.20	$ 1.29	$ 8.05	$ 0.00	$ 7.20	$ 1.29	$ 8.05
2026	$ 0.00	$ 5.43	$ 1.38	$ 8.05	$ 0.00	$ 7.20	$ 1.38	$ 8.05	$ 0.00	$ 7.20	$ 1.38	$ 8.05
2027	$ 0.00	$ 5.43	$ 1.47	$ 8.05	$ 0.00	$ 7.20	$ 1.47	$ 8.05	$ 0.00	$ 7.20	$ 1.47	$ 8.05
2028	$ 0.00	$ 5.43	$ 1.56	$ 8.05	$ 0.00	$ 7.20	$ 1.56	$ 8.05	$ 0.00	$ 7.20	$ 1.56	$ 8.05
2029	$ 0.00	$ 5.43	$ 1.65	$ 8.05	$ 0.00	$ 7.20	$ 1.65	$ 8.05	$ 0.00	$ 7.20	$ 1.65	$ 8.05
2030	$ 0.00	$ 5.43	$ 1.78	$ 8.05	$ 0.00	$ 7.20	$ 1.78	$ 8.05	$ 0.00	$ 7.20	$ 1.78	$ 8.05
2031	$ 0.00	$ 5.43	$ 1.92	$ 8.05	$ 0.00	$ 7.20	$ 1.92	$ 8.05	$ 0.00	$ 7.20	$ 1.92	$ 8.05
2032	$ 0.00	$ 5.43	$ 2.06	$ 8.05	$ 0.00	$ 7.20	$ 2.06	$ 8.05	$ 0.00	$ 7.20	$ 2.06	$ 8.05
2033	$ 0.00	$ 5.43	$ 2.20	$ 8.05	$ 0.00	$ 7.20	$ 2.20	$ 8.05	$ 0.00	$ 7.20	$ 2.20	$ 8.05
2034	$ 0.00	$ 5.43	$ 2.33	$ 8.05	$ 0.00	$ 7.20	$ 2.33	$ 8.05	$ 0.00	$ 7.20	$ 2.33	$ 8.05
2035	$ 0.00	$ 5.43	$ 2.47	$ 8.05	$ 0.00	$ 7.20	$ 2.47	$ 8.05	$ 0.00	$ 7.20	$ 2.47	$ 8.05
2036	$ 0.00	$ 5.43	$ 2.62	$ 8.05	$ 0.00	$ 7.20	$ 2.62	$ 8.05	$ 0.00	$ 7.20	$ 2.62	$ 8.05
2037	$ 0.00	$ 5.43	$ 2.77	$ 8.05	$ 0.00	$ 7.20	$ 2.77	$ 8.05	$ 0.00	$ 7.20	$ 2.77	$ 8.05
2038	$ 0.00	$ 5.43	$ 2.94	$ 8.05	$ 0.00	$ 7.20	$ 2.94	$ 8.05	$ 0.00	$ 7.20	$ 2.94	$ 8.05
2039	$ 0.00	$ 5.43	$ 3.12	$ 8.05	$ 0.00	$ 7.20	$ 3.12	$ 8.05	$ 0.00	$ 7.20	$ 3.12	$ 8.05
2040	$ 0.00	$ 5.43	$ 3.30	$ 8.05	$ 0.00	$ 7.20	$ 3.30	$ 8.05	$ 0.00	$ 7.20	$ 3.30	$ 8.05
2041	$ 0.00	$ 5.43	$ 3.50	$ 8.05	$ 0.00	$ 7.20	$ 3.50	$ 8.05	$ 0.00	$ 7.20	$ 3.50	$ 8.05
2042	$ 0.00	$ 5.43	$ 3.71	$ 8.05	$ 0.00	$ 7.20	$ 3.71	$ 8.05	$ 0.00	$ 7.20	$ 3.71	$ 8.05
2043	$ 0.00	$ 5.43	$ 3.93	$ 8.05	$ 0.00	$ 7.20	$ 3.93	$ 8.05	$ 0.00	$ 7.20	$ 3.93	$ 8.05
2044	$ 0.00	$ 5.43	$ 4.16	$ 8.05	$ 0.00	$ 7.20	$ 4.16	$ 8.05	$ 0.00	$ 7.20	$ 4.16	$ 8.05
2045	$ 0.00	$ 5.43	$ 4.41	$ 8.05	$ 0.00	$ 7.20	$ 4.41	$ 8.05	$ 0.00	$ 7.20	$ 4.41	$ 8.05
2046	$ 0.00	$ 5.43	$ 4.68	$ 8.05	$ 0.00	$ 7.20	$ 4.68	$ 8.05	$ 0.00	$ 7.20	$ 4.68	$ 8.05
2047	$ 0.00	$ 5.43	$ 4.95	$ 8.05	$ 0.00	$ 7.20	$ 4.95	$ 8.05	$ 0.00	$ 7.20	$ 4.95	$ 8.05
2048	$ 0.00	$ 5.43	$ 5.25	$ 8.05	$ 0.00	$ 7.20	$ 5.25	$ 8.05	$ 0.00	$ 7.20	$ 5.25	$ 8.05
2049	$ 0.00	$ 5.43	$ 5.56	$ 8.05	$ 0.00	$ 7.20	$ 5.56	$ 8.05	$ 0.00	$ 7.20	$ 5.56	$ 8.05
2050	$ 0.00	$ 5.43	$ 5.90	$ 8.05	$ 0.00	$ 7.20	$ 5.90	$ 8.05	$ 0.00	$ 7.20	$ 5.90	$ 8.05
Levelized												
2018-2027	$ 0.00	$ 5.43	$ 1.05	$ 8.05	$ 0.00	$ 7.20	$ 1.05	$ 8.05	$ 0.00	$ 7.20	$ 1.05	$ 8.05
2018-2032	$ 0.00	$ 5.43	$ 1.28	$ 8.05	$ 0.00	$ 7.20	$ 1.28	$ 8.05	$ 0.00	$ 7.20	$ 1.28	$ 8.05
2018-2047	$ 0.00	$ 5.43	$ 2.22	$ 8.05	$ 0.00	$ 7.20	$ 2.22	$ 8.05	$ 0.00	$ 7.20	$ 2.22	$ 8.05

Note: This table uses emission rates specified in Table 20 and Table 21. The first set of CO_2 values are based on the RGGI price forecast used in AESC 2018 (see Figure 20). CO_2 and Nitrogen emission prices are described in Chapter 8 Non-Embedded Environmental Costs. For this table we assume a 50/50 mix of NO and NO_2. No prices were developed for SO_X emissions, but the emission rates are so low that we use a proxy zero value for their costs here. Levelized values are calculated using a Real Discount rate of 1.34 percent.

Table 132. Diesel Fuel DRIPE by state ($/MMBtu per MMBtu reduced)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE						
	NE	CT	MA	ME	NH	RI	VT	NE	CT	MA	ME	NH	RI	VT
2018	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.06	0.08	0.08	0.08	0.08
2019	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.00	0.08	0.06	0.08	0.09	0.09	0.09
2020	0.10	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.09	0.09	0.10
2021	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.10	0.10	0.10
2022	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.10	0.10	0.10
2023	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.10	0.10	0.10
2024	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.09	0.10	0.10	0.10
2025	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.10
2026	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2027	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2028	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.10
2029	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.09	0.10	0.10	0.10
2030+	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
Levelized (2018–2030)	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.10	0.10	0.10

Table 133. Residual Fuel Oil DRIPE by state ($/MMBtu per MMBtu reduced)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE						
	NE	CT	MA	ME	NH	RI	VT	NE	CT	MA	ME	NH	RI	VT
2018	0.09	0.02	0.03	0.01	0.01	0.01	0.01	0.00	0.07	0.06	0.08	0.08	0.08	0.09
2019	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.00	0.08	0.06	0.09	0.09	0.09	0.09
2020	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.09	0.10	0.10
2021	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.10	0.10	0.10
2022	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.10
2023	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2024	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2025	0.12	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2026	0.12	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.11	0.11
2027	0.12	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.11	0.11
2028	0.12	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2029	0.11	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.10	0.11
2030+	0.12	0.03	0.04	0.02	0.01	0.01	0.01	0.00	0.09	0.07	0.10	0.10	0.11	0.11
Levelized (2018–2030)	0.11	0.02	0.04	0.02	0.01	0.01	0.01	0.00	0.08	0.07	0.09	0.10	0.10	0.10

APPENDIX E. FINANCIAL PARAMETERS

This appendix presents values for converting nominal dollars to constant 2018 dollars (2018 $) as well as a real discount rate for calculating illustrative levelized avoided costs. These values are used throughout the 2018 AESC Study, including in calculations that convert constant to nominal dollars and in levelization calculations.

In summary, we are used a long-term inflation rate similar to those used in past versions of the AESC study, but a lower real discount rate than has previously been used based on the recent rates for U.S. Treasury Bills. Those values are below:

- The value for converting between future nominal dollars and constant 2018$ is a long-term inflation rate of 2.00 percent (versus 1.88 percent in AESC 2015).
- The real discount rate is 1.34 percent (versus 2.43 percent in AESC 2015).

Conversion of Nominal Dollars to Constant 2018 Dollars

Unless otherwise stated, all dollar values in AESC 2018 are in 2018 dollars. Therefore, a set of inflators is needed to convert prior year nominal dollars into 2018 dollars (2018$), and a set of deflators to convert future year nominal dollars into 2018 dollars. Those values are presented in Table 134. The inflators are calculated from the GDP chain-type price index published by the U.S. Department of Commerce's Bureau of Economic Analysis (BEA).[267]

Table 134. GDP price index and inflation rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2018$
2000	81.89		1.410
2001	83.75	2.28%	1.379
2002	85.04	1.53%	1.358
2003	86.74	1.99%	1.331
2004	89.12	2.75%	1.296
2005	91.99	3.22%	1.255
2006	94.81	3.07%	1.218
2007	97.34	2.66%	1.186
2008	99.25	1.96%	1.163
2009	100.00	0.76%	1.155
2010	101.22	1.22%	1.141

[267] BEA, Table 1.1.9 Implicit Price Deflators for Gross Domestic Product, 10/11/17.

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2018$
2011	103.31	2.06%	1.118
2012	105.21	1.84%	1.097
2013	106.91	1.61%	1.080
2014	108.83	1.79%	1.061
2015	110.01	1.08%	1.050
2016	111.42	1.28%	1.036
2017	113.20	1.60%	1.020
2018	**115.46**	**2.00%**	**1.000**
2019	117.77	2.00%	0.980
2020	120.13	2.00%	0.961
2021	122.53	2.00%	0.942
2022	124.98	2.00%	0.924
2023	127.48	2.00%	0.906
2024	130.03	2.00%	0.888
2025	132.63	2.00%	0.871
2026	135.28	2.00%	0.853
2027	137.99	2.00%	0.837
2028	140.75	2.00%	0.820
2029	143.56	2.00%	0.804
2030	146.43	2.00%	0.788
2031	149.36	2.00%	0.773
2032	152.35	2.00%	0.758
2033	155.40	2.00%	0.743
2034	158.51	2.00%	0.728
2035	161.68	2.00%	0.714
2036	164.91	2.00%	0.700
2037	168.21	2.00%	0.686
2038	171.57	2.00%	0.673
2039	175.00	2.00%	0.660
2040	178.50	2.00%	0.647
2041	182.07	2.00%	0.634
2042	185.71	2.00%	0.622
2043	189.43	2.00%	0.610
2044	193.22	2.00%	0.598
2045	197.08	2.00%	0.586
2046	201.02	2.00%	0.574
2047	205.04	2.00%	0.563
2048	209.14	2.00%	0.552
2049	213.33	2.00%	0.541
2050	217.59	2.00%	0.531

For projected years in our analysis, we used a long-term **inflation rate of 2.00 percent**. This is the same inflation rate used in the AESC 2013 study. It is also consistent with the 20-year annual average inflation rate from 1992 to 2012 of 1.88 percent, derived from the GDP chain-type price index, which was the value used in the 2015 AESC study. We also examined projections of long-term inflation made by the Congressional Budget Office (CBO) in January 2017 which were 2.00 percent.[268] Note also that the long-term rate used in the 2017 Annual Energy Outlook (AEO) was 2.10 percent.[269]

Real Discount Rate

The calculation of the real discount rate uses the inflation rate, as discussed above, in conjunction with the long-term nominal discount rate. Past AESC studies have used 30-year Treasury bills to inform the long-term rate discount rate. Rates on Treasury bills have declined dramatically in recent years and now stand at 3.04 percent—well below historical values. These recent rates are also significantly below the 10-year Treasury notes rate of 3.70 percent. To better align with historical values and the 10-year rate, we used a composite value based on the shorter-term rate for 10 years to be followed by the lower longer-term rate. This results in a **nominal discount rate of 3.37 percent**. The calculations for this are shown in Table 135.

Table 135. Composite nominal rate calculation

Year	Rate	Index	Year	Rate	Index
2018	3.70%	1.000	2036	3.04%	1.828
2019	3.60%	1.037	2037	3.04%	1.883
2020	3.70%	1.075	2038	3.04%	1.940
2021	3.70%	1.115	2039	3.04%	1.999
2022	3.70%	1.156	2040	3.04%	2.060
2023	3.70%	1.199	2041	3.04%	2.123
2024	3.70%	1.244	2042	3.04%	2.187
2025	3.70%	1.290	2043	3.04%	2.254
2026	3.70%	1.337	2044	3.04%	2.323
2027	3.70%	1.387	2045	3.04%	2.393
2028	3.04%	1.438	2046	3.04%	2.466
2029	3.04%	1.482	2047	3.04%	2.541
2030	3.04%	1.527	2048	3.04%	2.618
2031	3.04%	1.573	2049	3.04%	2.698
2032	3.04%	1.621	2050	3.04%	2.780
2033	3.04%	1.670	**20-year (2018 to 2038)**	**3.37%**	
2034	3.04%	1.721			
2035	3.04%	1.774			

Notes: 10-year T-Notes are used for through 2027; 30-year T-Notes are used thereafter.

[268] Congressional Budget Office. 2017. The Budget and Economic Outlook: Fiscal Years 2017 to 2027, Table 2-1, page 108.

[269] EIA AEO 2017, Macroeconomic Indicators, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2017&cases=ref2017&sourcekey=0 (retrieved 10/6/17).

AESC 2018 requires the calculation of illustrative levelized avoided costs expressed in 2018 $ for various intervals using the identified real discount rate. Note that the published avoided cost user interface allows readers of AESC 2018 to input any discount rate they prefer to calculate levelized avoided costs.

To develop a real discount rate, we used the calculated nominal rate and the forecast long-term inflation rate (2.00 percent) according to the following formula:

Real discount rate = ((1+nominal_rate)/(1+inflation_rate)-1)

This formula produces a real discount rate of 1.34 percent, which appears reasonable for calculations of levelized costs through periods as long as 30 years.[270] This is significantly lower than the AESC 2015 rate of 2.43 percent. But as discussed above, the longer-term nominal rates have declined considerably. We thus used a **real discount rate of 1.34 percent**. Table 136 presents a summary of the values we compared.

Table 136. Comparison of real discount rate estimates

	AESC 2015	AESC 2018	Treasury Bill Method *Feb 2018*	Congressional Budget Office *Jan 2015*	*Jun 2017*
Long-term nominal rate	4.36%	**3.37%**	3.04%	4.60%	3.70%
Source	Composite CBO thru 2024, AEO 2014 thru 2030	**Composite of 10 and 30-year Treasury rates**	30-year T-Bills over last six years	Forecast - 10 yr Treasury notes 2020–2025	Forecast - 10 yr Treasury notes 2021–2027
Inflation Rate	1.88%	**2.00%**	**2.00%**	2.00%	2.00%
Source	Composite CBO thru 2024, AEO 2014 thru 2030	**Above historical average of 1.88%, but below AEO 2017 projection of 2.1%. Same as CBO forecast**	Above historical average, but below AEO 2017 projection of 2.1%.	Consistent with GDP price index 2020–2025 forecast	Core PCE Price Index 2021–2027
Resulting long-term real rate	2.43%	**1.34%**	1.02%	2.55%	1.67%

Sources: January 2015 CBO rate is taken from "The Budget and Economic Outlook: Fiscal Years 2015 to 2025," Congressional Budget Office, January 2015, Table 2-1. January 2017 CBO rate is taken from The Budget and Economic Outlook: Fiscal Years 2017 to 2027, Congressional Budget Office, June 2017, Table 2-1.

[270] This is the standard rate conversion equation used widely and in all previous AESC studies.

APPENDIX F. USER INTERFACE

New to AESC 2018 is the development of the Avoided Cost User Interface. This Excel-based document allows readers of AESC 2018 to examine hour-by-hour energy prices and DRIPE values for each reporting region, for 2018 through 2035. This document serves as a data aggregator; it pulls together energy and DRIPE data for the traditional AESC costing periods and discount rates, allowing users to view—and modify—levelized avoided costs. This document also provides an extrapolation of energy prices and DRIPE values through 2050, using the assumption that all values after 2035 are calculated using the five-year cumulative average growth rate from 2031 to 2035.

However, the main purpose of this document is to allow users to develop avoided costs for periods outside the traditional AESC costing periods of summer off-peak, summer on-peak, winter off-peak, and winter on-peak. Within the Avoided Cost User Interface, users can develop customized costs using the following selectable options:

- **Time period:** Energy and DRIPE values are provided modeled from 2018 through 2035, and they are extrapolated through 2050.
- **Levelization period:** Users can view costs levelized using the standard levelization periods (10-year, 15-year, and 20-year), or develop their own levelization periods over other years.
- **AESC reporting zone:** Users may choose one of 11 reporting regions for which to calculate avoided costs
- **Costing period:** Users can view the costs under the traditional four costing periods, or define their own, as follows:
    - Peak load (defined as "X" percent of hours exceeding "Y" percentile of load)
    - Load threshold (defined as "X" hours exceeding "Y MW")
    - Peak price (defined as "X" percent of hours exceeding "Y" percentile of price)
    - Price threshold (defined as "X" hours exceeding "$Y/MWh")
- **Modeling sensitivity:** Users may create avoided costs for the main AESC 2018 case, the High Load sensitivity, or the With EE sensitivity.

APPENDIX G. MASSACHUSETTS GWSA REGULATIONS COMPLIANCE COSTS

AESC 2018 integrates two promulgated electric-sector regulations in Massachusetts into its electric-sector modeling: 310 CMR 7.74 (a mass-based, declining cap on in-state CO_2 emissions) and 310 CMR 7.75 (the Clean Energy Standard) to represent a reasonable and current estimate for the cost of compliance for the Massachusetts GWSA regulations. As stated earlier, 310 CMR 7.74 assigns declining limits on total annual greenhouse gas emissions from identified emitting power plants within Massachusetts. AESC 2018 models this regulation as a state-wide limit through which plants receive CO_2 allowances at the start of each year. 310 CMR 7.75 obligates LSEs to provide a minimum percentage of load from clean energy resources above RPS Class I requirements. CES-eligible resources include any projects certified under the Class I Massachusetts RPS; *or* projects that are not Massachusetts Class I RPS eligible but have 20-yr lifetime net GHG impacts equal to 50 percent of a new natural gas combined cycle facility.

GWSA Compliance Costs

Table 137 summarizes embedded and non-embedded GWSA cost of compliance for both CMR 7.74 and 7.75.[271] The AESC 2018 embedded cost of GWSA compliance on a 15-year levelized basis is $16.59 per short ton. The non-embedded cost of GWSA compliance on a 15-year levelized basis is $83.41 per short ton. Note that the embedded cost of compliance with CMR 7.74 shows significant variation year-to-year; this is a caused by year-to-year changes in fuel prices, unit additions and retirements, and maintenance and refueling outages (particularly for nuclear units, which are most typically on 18-month refueling schedules).

[271] These calculations assume a global marginal abatement cost of $100 per short ton. These calculations could also be re-evaluated using the New England-centric marginal abatement cost of $174 per short ton, described in Chapter 8 *Non-Embedded Environmental Costs.*

Table 137. GWSA compliance costs

Year	AESC 2018 Non-embedded CO2 Cost (2018$/ton) *a*	Embedded Cost of RGGI (2018$/ton) *b*	Embedded Cost of Compliance for CMR 7.74 (2018$/ton) *c*	Embedded Cost of Compliance for CMR 7.75 (2018$/ton) *d*	Total embedded GWSA Cost of Compliance (2018$/ton) *e=b+c+d*	Non-embedded GWSA Cost of Compliance (2018$/ton) *f=a-e*
2018	$100.00	$6.10	$0.00	$1.46	$7.56	$92.44
2019	$100.00	$8.67	$0.00	$4.55	$13.22	$86.78
2020	$100.00	$11.14	$0.01	$4.92	$16.07	$83.93
2021	$100.00	$11.62	$0.00	$3.13	$14.75	$85.25
2022	$100.00	$12.07	$0.00	$0.00	$12.07	$87.93
2023	$100.00	$12.50	$0.00	$0.00	$12.50	$87.50
2024	$100.00	$13.26	$0.00	$0.00	$13.26	$86.74
2025	$100.00	$13.98	$0.49	$0.00	$14.47	$85.53
2026	$100.00	$14.67	$1.07	$0.00	$15.74	$84.26
2027	$100.00	$15.29	$4.20	$0.00	$19.49	$80.51
2028	$100.00	$15.89	$4.80	$0.00	$20.69	$79.31
2029	$100.00	$16.46	$7.52	$0.04	$24.02	$75.98
2030	$100.00	$17.48	$10.56	$0.08	$28.12	$71.88
2031	$100.00	$18.46	$0.00	$0.11	$18.57	$81.43
2032	$100.00	$19.39	$2.27	$0.27	$21.93	$78.07
Levelized (2018-2032)	**$100.00**	**$13.60**	**$1.95**	**$1.04**	**$16.59**	**$83.41**

Note: Real discount rate of 1.34 percent. Embedded cost of compliance based on EnCompass model runs and CES cost estimates. Values displayed in columns e and f may not match the sums of other columns due to rounding.

Conversion of GWSA Compliance Costs for other Fuels

AESC 2018 converts GWSA compliance costs associated with both 310 CMR 7.74 and 7.75 and for each regulation individually from $/MWh and $/ton into $/MMBtu. These values may be incorporated by users for other analyses. Table 138 summarizes embedded and non-embedded GWSA compliance costs for other fuels. Note that values in this table do not incorporate costs associated with RGGI, as RGGI costs are only applied to the electric power sector. Note also that the embedded cost of compliance with CMR 7.74 shows significant variation year-to-year; this is a caused by year-to-year changes in fuel prices, unit additions and retirements, and maintenance and refueling outages (particularly for nuclear units, which are most typically on 18-month refueling schedules).

Table 138. GWSA compliance costs for other fuels (2018$/MMBtu)

	Distillate Fuel Oil			B5 Biofuel			B20 Biofuel			Kerosene			Liquid Propane Gas			Residual Fuel Oil		
	a	*b*	*c=a-b*	*d*	*e*	*f=d-e*	*g*	*h*	*i=g-h*	*j*	*k*	*l=j-k*	*m*	*n*	*o=m-n*	*p*	*q*	*r=p-q*
2018	$8.34	$0.12	$8.22	$7.93	$0.11	$7.82	$6.68	$0.09	$6.59	$8.24	$0.12	$8.12	$7.20	$0.10	$7.10	$8.96	$0.13	$8.84
2019	$8.34	$0.37	$7.98	$7.93	$0.35	$7.58	$6.68	$0.29	$6.39	$8.24	$0.36	$7.88	$7.20	$0.32	$6.89	$8.96	$0.39	$8.57
2020	$8.34	$0.40	$7.95	$7.93	$0.38	$7.55	$6.68	$0.32	$6.37	$8.24	$0.39	$7.85	$7.20	$0.34	$6.86	$8.96	$0.43	$8.54
2021	$8.34	$0.25	$8.09	$7.93	$0.24	$7.69	$6.68	$0.20	$6.48	$8.24	$0.25	$7.99	$7.20	$0.22	$6.98	$8.96	$0.27	$8.69
2022	$8.34	$0.00	$8.34	$7.93	$0.00	$7.93	$6.68	$0.00	$6.68	$8.24	$0.00	$8.24	$7.20	$0.00	$7.20	$8.96	$0.00	$8.96
2023	$8.34	$0.00	$8.34	$7.93	$0.00	$7.93	$6.68	$0.00	$6.68	$8.24	$0.00	$8.24	$7.20	$0.00	$7.20	$8.96	$0.00	$8.96
2024	$8.34	$0.00	$8.34	$7.93	$0.00	$7.93	$6.68	$0.00	$6.68	$8.24	$0.00	$8.24	$7.20	$0.00	$7.20	$8.96	$0.00	$8.96
2025	$8.34	$0.03	$8.31	$7.93	$0.03	$7.90	$6.68	$0.03	$6.66	$8.24	$0.03	$8.20	$7.20	$0.03	$7.17	$8.96	$0.04	$8.93
2026	$8.34	$0.07	$8.27	$7.93	$0.07	$7.86	$6.68	$0.06	$6.63	$8.24	$0.07	$8.17	$7.20	$0.06	$7.14	$8.96	$0.08	$8.89
2027	$8.34	$0.28	$8.06	$7.93	$0.27	$7.66	$6.68	$0.23	$6.46	$8.24	$0.28	$7.96	$7.20	$0.24	$6.96	$8.96	$0.30	$8.66
2028	$8.34	$0.32	$8.03	$7.93	$0.30	$7.63	$6.68	$0.25	$6.43	$8.24	$0.31	$7.93	$7.20	$0.27	$6.93	$8.96	$0.34	$8.62
2029	$8.34	$0.49	$7.85	$7.93	$0.47	$7.46	$6.68	$0.39	$6.29	$8.24	$0.48	$7.75	$7.20	$0.42	$6.78	$8.96	$0.53	$8.44
2030	$8.34	$0.68	$7.67	$7.93	$0.64	$7.29	$6.68	$0.54	$6.14	$8.24	$0.67	$7.57	$7.20	$0.58	$6.62	$8.96	$0.73	$8.24
2031	$8.34	$0.01	$8.33	$7.93	$0.01	$7.92	$6.68	$0.01	$6.68	$8.24	$0.01	$8.23	$7.20	$0.01	$7.19	$8.96	$0.01	$8.95
2032	$8.34	$0.16	$8.18	$7.93	$0.15	$7.78	$6.68	$0.13	$6.56	$8.24	$0.16	$8.08	$7.20	$0.14	$7.06	$8.96	$0.17	$8.79
Levelized 2018-2032	**$8.34**	**$0.21**	**$8.13**	**$7.93**	**$0.20**	**$7.73**	**$6.68**	**$0.17**	**$6.52**	**$8.24**	**$0.21**	**$8.03**	**$7.20**	**$0.18**	**$7.02**	**$8.96**	**$0.23**	**$8.74**

Notes: All values are in 2018$/MMBtu. Columns a, d, g, j, m, and p represent the non-embedded carbon costs associated with each fuel-type based EIA emission rates. Columns b, e, h, k, n, and q represent the embedded GWSA costs for each fuel. Columns c, f, i, l, o, and r represent the non-embedded GWSA cost of compliance for each fuel type.

APPENDIX H. DRIPE DERIVATION

This appendix describes the derivation of demand reduction induced price effects (DRIPE)—effectively, the price effect of adding energy efficiency resources or reducing load.

For the supply curve (the price that suppliers will charge for supplying *x* MW):

$$S_0 = b_S + m_s x,$$

and the demand curve (the price set by the VRR curve for *x* MW):

$$D_0 = b_D - m_D x$$

Note that m_D is the magnitude of the slope with the direction noted in the preceding negative sign.

The demand curve meets the supply curve at

$$x \quad = \frac{b_D - b_s}{m_s + m_D}$$

And the market-clearing price is

$$Price \quad = b_D - m_D \left(\frac{b_D - b_s}{m_s + m_D} \right)$$

A positive horizontal shift of α MW to the supply curve shifts the supply y-intercept downward. A negative horizontal shift of the demand curve shifts the demand y-intercept downward as well.

The horizontal shift of the supply curve shifts its y-intercept:

$$b_{supply\ shifted} = b_S - m_S \alpha$$

The Supply function, horizontally shifted + α units, equals:

$$S_{shifted} = m_s x + (b_S - m_s \alpha) = m_s(x - \alpha) + b_S$$

Similarly, applying a negative horizontal shift of α units to the demand curve shifts its y-intercept:

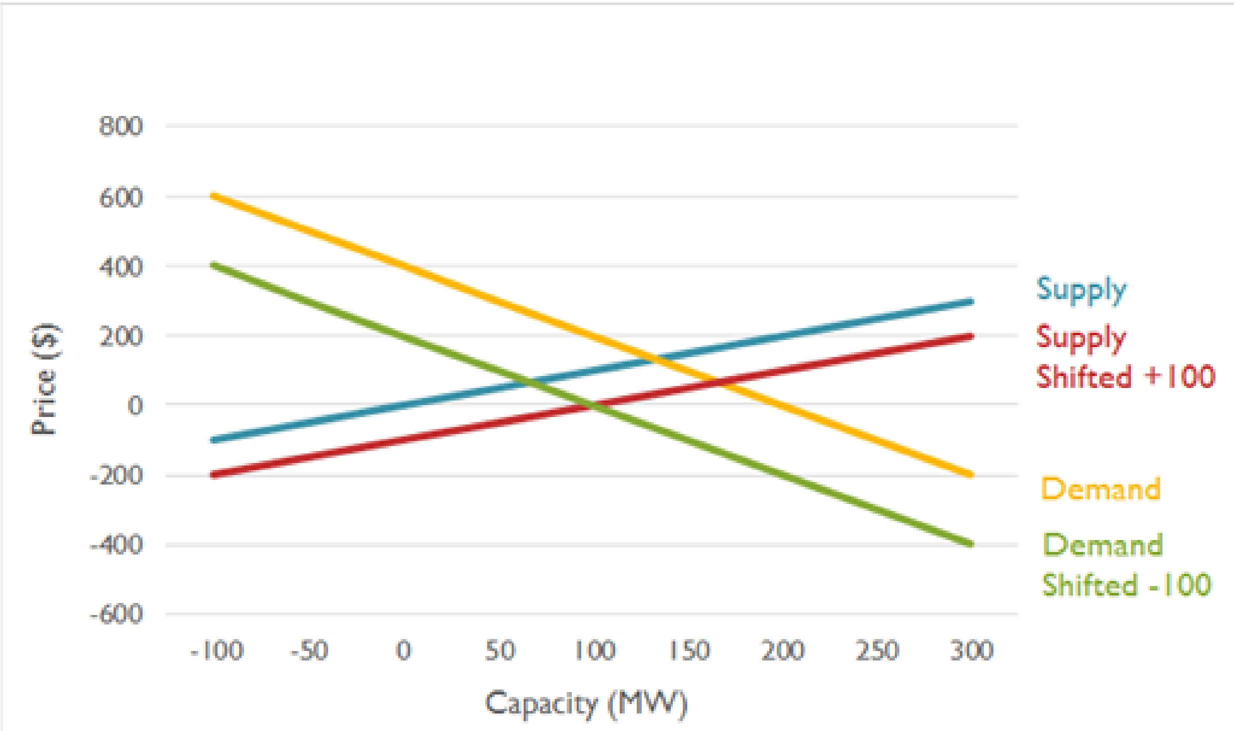
$$b_{demand\ shifted} = b_D - m_D \alpha$$

The shifted Demand function equals:

$$D_{shifted} = b_D - m_D(\alpha + x)$$

Figure 57 provides examples that describe the rationale for the shift in the y-intercept for each function. The supply function is S = x + 0 and the demand function is D = 400–2x. Adding 100 MW at $0 shifts the supply curve right by 100×$m_S = 100$. Subtracting 100 MW from the demand curve likewise shifts that curve left by 100, equivalent to shifting down by 100×m_p = 200.

Figure 57. Example of supply and demand impact



For the intersection of the supply curve S_0 with the VRR $D_{shifted}$ and the intersection of $S_{shifted}$ with D_0, we find the equilibrium quantity x^* and then substitute that into either half to get $Price^*$.

For $\boldsymbol{S_0 = D_{shifted}}$

$$m_s x + b_S = b_D - m_D(\alpha + x)$$

Solve for x

$$x^* = \frac{b_D - b_s + m_s\alpha}{m_s + m_D}$$

$$Substitute\ x^*\ into\ S_0\ or\ D_{shifted}\ to\ get\ Price$$

$$Price^* = b_D - m_D\left(\frac{b_D - b_s + m_s\alpha}{m_s + m_D}\right)$$

The difference between this price and the original price is

$$\Delta Price \quad = m_D\left(\frac{m_s\alpha}{m_s + m_D}\right)$$

Thus, the slope of the clearing price with respect to demand is

$$\left(\frac{m_D \times m_s}{m_s + m_D}\right)$$

The same approach gives the same result, starting with an increment in supply.

APPENDIX I. MATRIX OF RELIABILITY SOURCES

This appendix documents the studies reviewed in AESC 2018 to develop Chapter 11 *Value of Improved Reliability*.

Table 139. Matrix of reliability sources

Year	Author	*Title*	Journal or Source	Document Focus
2017	Makovich, L., Richards, J.	*Ensuring Resilient and Efficiency Electricity Generation: the Value of the Current Diverse US power supply portfolio*	IHS Market, research supported by the Edison Electric Institute available at: https://www.globalenergyinstitute.org/sites/default/files/Value%20of%20the%20Current%20Diverse%20US%20Power%20Supply%20Portfolio_V3-WB.PDF	Reliability Value Assessment – Macroeconomic Metrics
2017	Mills, E., Jones, R.	*An Insurance Perspective on U.S. Electric Grid Disruption Costs*	LBNL-1006392, performed by the Energy Analysis and Environmental Impacts Division Lawrence Berkeley National Laboratory https://emp.lbl.gov/sites/default/files/lbnl-1006392.pdf	Reliability Value Assessment – VoLL by Sector per Event
2017	North American Electric Reliability Corporation	*Distributed Energy Resources: Connection Modeling and Reliability Considerations*	A report by NERC and the NERC Essential Reliability Services Working Group (ERSWG) Available at: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DERTF%20Draft%20Report%20-%20Connection%20Modeling%20and%20Reliability%20Considerations.pdf	Alternative Reliability Metrics
2017	U.S. Department of Energy	*Valuation of Energy Security for the United States*	U.S. Department of Energy, Report to Congress. Available at: https://www.energy.gov/sites/prod/files/2017/01/f34/Valuation%20of%20Energy%20Security%20for%20the%20United%20States%20%28Full%20Report%29_1.pdf	Reliability Value Assessment – VoLL Methods
2016	Nateghi, R., Guikema, S.D., Wu, y., Bruss, B.	*Critical Assessment of the Foundations of Power Transmission and Distribution Reliability Metrics and Standards*	Risk analysis, Vol 36, No. 1, 2016: DOI: 10.1111/risa.12401 Available for free download: https://www.researchgate.net/publication/276357284_Critical_Assessment_of_the_Foundations_of_Power_Transmission_and_Distribution_Reliability_Metrics_and_Standards_Foundations_of_Power_Systems_Reliability_Standards	Alternative Reliability Metrics

Year	Author	*Title*	Journal or Source	Document Focus
2016	Diskin, P.T., Washko, D.M.	*Pennsylvania Electric Reliability Report 2015*	Published by Pennsylvania Public Utility Commission http://www.puc.pa.gov/General/publications_reports/pdf/Electric_Service_Reliability2015.pdf	Reliability Reporting – Outage Causes
2016	GridSolar, LLC	*Final Report Boothbay Sub-Regions Smart Grid Reliability Pilot Project*	Prepared for Docket No. 2011-138, Central Maine Power Co., Request for Approval of Non-Transmission Alternative (NTA) Pilot Project of the Mid-Coast and Portland Areas January 19, 2016	Reliability Metrics – Alternative Reporting
2016	Ponemon Institute Research Center	*Cost of Data Center Outages*	Part of the Data Center Performance Benchmark Series, sponsored by Emerson Network Power. Available at: https://planetaklimata.com.ua/instr/Liebert_Hiross/Cost_of_Data_Center_Outages_2016_Eng.pdf	Reliability Value Assessment- VoLL for Data Centers
2015	Schroder, T., & Kuckshinrichs, W.	*Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*	Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), Forschungszentrum Julich BMbH, Julich, Germany. Available at: https://juser.fz-juelich.de/record/279293/files/fenrg-03-00055.pdf	Reliability Value Assessment – VoLL Methods
2015	Sullivan, M.J., Schellenber, J., Blundell, M.	*Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*	LBNL report funded by Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231., LBNL-6941E, January 2015. Available at: https://emp.lbl.gov/sites/default/files/lbnl-6941e.pdf	Reliability Value Assessment – VoLL by Sector, Region and Duration
2014	Khujadze, S., Delphia, J.	*A Study of the Value of Lost Load (VOLL) for Georgia*	Report prepared for USAID Hydro Power and Energy Planning Project, Contract Number AID-OAA-I-13-00018/AID-114-TO-13-00006 Deloitte Consulting LLP. Available at: https://dec.usaid.gov/dec/content/Detail.aspx?ctID=ODVhZjk4NWQtM2YyMi00YjRmLTkxNjktZTcxMjM2NDBmY2Uy&rID=MzQ5MTg3	Reliability Value Assessment- VoLL Country Studies
2013	Pfeifenberger, J.P., Spees, K.	*Resource Adequacy Requirements: Reliability and Economic Implications*	Report prepared by Brattle for FERC. Available at: https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf	Reliability Value Assessment - Planning Reserve Margins

Year	Author	*Title*	Journal or Source	Document Focus
2013	London Economics International, LLC	*Estimating the Value of Lost Load*	Briefing paper prepared for the Electric Reliability Council of Texas, Inc. (June 17, 2013). Available at: http://www.ercot.com/content/gridinfo/resource/2014/mktanalysis/ERCOT_ValueofLostLoad_LiteratureReviewandMacroeconomic.pdf	Reliability Value Assessment (Literature Review)
2012	Electric Reliability Council of Texas, Inc., Laser, W.	*Resource Adequacy and Reliability Criteria Considerations*	Presented at PUC Workshop: Commission Proceeding Regarding Policy Options on Resource Adequacy, July 27, 2012 http://www.ercot.com/content/gridinfo/resource/2012/mktanalysis/ERCOT%20Presentation%20for%20PUCT%20July%2027%202012%20Workshop.pdf	Reliability Value Assessment - Planning Reserve Margins
2011	Rouse, G., Kelly, J.	*Electricity Reliability: Problems, Progress and Policy Solutions Galvin Electricity Initiative*	Galvin Electricity Inititiative. Available at: http://galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf	Reliability Metrics- Outage Reporting Metrics Review
2010	Centolella	*Estimates of the Value of Uninterrupted Service for the Mid-West Independent System Operator*	Available at: https://sites.hks.harvard.edu/hepg/Papers/2010/VOLL%20Final%20Report%20to%20MISO%20042806.pdf	Reliability Value Assessment – VoLL Midwest Study
2008	Ventyx	*Analysis of "Loss of Load Probability" (LOLP) at Various Planning Reserve Margins*	Available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Attachment-2.10-1-LOLP-Study.pdf	Reliability Metrics - LOLP and Planning Reserve
2006	LaCommare, K.H., Eto, J.H.	*Cost of Power Interruptions to Electricity Consumers in the United States*	LBNL-58164, Report funded by U.S. Department of Energy under Contract NO. DE-AC02-05CH11231. Available at: https://emp.lbl.gov/sites/all/files/report-lbnl-58164.pdf	Reliability Value VoLL- Annual Total Costs by Sector and Region
2004	LaCammara, K.H., Eto, J.H.	*Understanding the Cost of Power Interruptions to U.S. Electricity Consumers.*	Ernest Orlando LBNL Environmental Energy Technologies Division. LBNL-55718. Report prepared by U.S. Department of Energy under Contract No. DE-AC03-76F00098. Available at: https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Understanding_Cost_of_Power_Interruptions.pdf	Reliability Value Assessment – VoLL by Sector and Duration

Year	Author	*Title*	Journal or Source	Document Focus
2004	Chowdhury, A. A., Mielnik, T.C., Lawion, L.e., Sullivan, M.J., and Katz, A.	*Reliability Worth Assessment in Electric Power Delivery Systems*	Power Engineering Society General Meeting, 2004 (Denver: IEEE), 654-660.	Reliability Value Assessment – VoLL Midwest Study
2003	Lawton, L. Sullivan, M., Van Liere, K., Katz, A., & Eto, J.	*A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys*	Prepared for Imre Gyuk Energy Storage Program, Office of Electric Transmission and Distribution U.S. Department of Energy. LBNL-54365. Available at: https://emp.lbl.gov/sites/all/files/lbnl-54365.pdf	Reliability Value Assessment – VoLL Sector, Region and Duration