nationalgrid

Andrew Marcaccio
Senior Counsel

December 17, 2021

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket 5189 – 2022 Annual Energy Efficiency Program Plan
<u>Responses to Record Requests (Complete Set)</u>

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), attached please find the electronic version of the Company's complete set of responses to the record requests issued at the Public Utilities Commission's ("PUCs") Evidentiary Hearing on December 6 and 7, 2021 in the above-referenced docket.[1] Bates stamp has been applied to the attached electronic version.

Thank you for your attention to this filing. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5189 Service List
John Bell, Division
Margaret Hogan, Esq.
Jon Hagopian, Esq.

[1] Per the Commission's request, the Company is providing one copy of this transmittal for the Commission's file in this docket and six (6) copies, 3-hole punched for the Commission.

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Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

Joanne M. Scanlon

December 17, 2021
Date

Docket No. 5189 - National Grid – 2022 Annual Energy Efficiency Program
Service list updated 12/16/2021

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Record Request No. 1

Request:

RR1 – Please identify all measures included in the reallocated $9M portion of the provisional plan with a BCR below 1.0, excluding economic benefits.

Response:

The Table below shows all measures included in the reallocated $9M portion of the provisional plan with a BCR below 1.0, excluding economic benefits from the BCR calculation. The Company notes that, while it assesses the cost effectiveness of all measures, in planning it applies the requirement from Section 3.2N of the LCP Standards that programs and portfolios must be cost effective.

In the Table below,

- The "Incremental Measure RI Test BCR" column shows the BCR calculation of the incremental quantities of those measures related to the reallocated $9 million.
- The "All Measure RI Test BCR" column shows the BCR calculation for all quantities of the measure in the Provision Plan.
- Most of the measures are cost effective when assessing the cost effectiveness of the total quantity of those measures in the Provisional Plan.
- Two measures, Upstream Heat Pump – Packaged in the Large Commercial New Construction Program and Heat Pumps in the Small Business Direct Install Program, are not cost effective as a standalone measure when assessing the cost effectiveness of the total quantity of those measures in the Provisional Plan. However, the programs in which they are located are both cost effective, with RI Test BCRs of 2.90 and 1.94, respectively, excluding economic benefits. The measures themselves are cost effective in the full program with the inclusion of economic benefits.

Record Request No. 1, page 2

Program	**Measure**	**All Measure RI Test BCR**	**Incremental Measure RI Test BCR**
Large Commercial New Construction	Upstream Heat Pump - Ductless	1.50	0.70
Large Commercial New Construction	Upstream Heat Pump - Packaged	0.99	0.45
Large Commercial New Construction	Upstream HVAC Refrigeration	1.09	0.50
Large Commercial New Construction	Refrigeration - Custom	2.14	1.00[1]
Large Commercial Retrofit	EI Light: Prescriptive	1.60	0.71
Large Commercial Retrofit	Compressed Air - Custom	1.12	0.53
Large Commercial Retrofit	HVAC - Custom	1.35	0.30
Large Commercial Retrofit	Motors & VFD - Custom	1.67	0.79
Large Commercial Retrofit	Refrigeration - Custom	1.40	0.64
Large Commercial Retrofit	Other - Custom	1.89	0.88
Small Business Direct Install	Heat Pumps	0.57	0.57
Small Business Direct Install	Lighting	1.12	0.49
Small Business Direct Install	Non-Lighting	2.81	0.75

[1] This measure is on this list because the full Incremental BCR value comes out to 0.996.

Record Request No. 2

Request:

RR2 – Please itemize the costs of each initiative, including both STAT and incentive costs, within the reallocated $9M portion of the provisional plan that is expected to result in future benefits.

Response:

The following table provides an itemized list of each initiative proposed within the $9 million portion of the Provisional Plan designed to result in future benefits. Some are likely to achieve moderate savings in the current year but may not result in net positive benefits in the current year. The majority focus on broadening the portfolio to enable future achievement of non-lighting savings.

Initiative Name	Initiative Summary	Amount
HVAC/controls vendor engagement*	The Company's current trade ally network is heavily weighted toward lighting vendors. This effort is to encourage program participation among HVAC, controls, and other non-lighting vendors, and to encourage existing trade allies to broaden their expertise into these areas. The Company anticipates that this effort will enable greater realization of HVAC/controls savings and benefits in future program years.	$150,000
HVAC early retirements**	Retire aging, inefficient HVAC equipment before the end of its useful life. Fixed contract cost + variable incentive costs. As awareness of this incentive grows, savings from this initiative will ramp up in future years. Unit costs will decline in future years as savings increase while costs remain fixed.	$313,946
SBDI air-source heat pumps displacing electric heating**	Replace electric resistance heating with air-source heat pumps. Encourages Small Business vendor to develop the capability to identify and install heat pumps. Once the vendor develops this capability (through training of existing staff and/or hiring new staff), it will become part of the SBDI "playbook" in future years, and incentive costs will be reassessed (and potentially reduced).	$512,500

Record Request No. 2, page 2

Commercial real estate initiative*	Traditionally a challenging sector for energy efficiency, National Grid has developed a Rhode Island-specific strategy to target both commercial real estate owners and tenants. Sector-oriented initiatives typically achieve modest savings in their first year before ramping up in future years once they are fully staffed, initial customer outreach is completed, processes are finalized, collateral is created, etc.	$300,000
Additional sales & engineering staff*	(1) an additional engineer with HVAC/controls expertise. This engineer will oversee development of tools and processes to streamline the technical review of HVAC and controls projects, which the Company and the EERMC believe provide the primary opportunities for savings growth in future years. (2) a sales representative will cover mid-sized customers, which have historically received less attention from sales staff and thus have more remaining low-hanging fruit. This will also enable senior sales staff to focus on larger customers. Sales staff typically generate modest savings in their first year before ramping up in future years due to the time required for training on internal processes and relationship-building with customers.	$317,000
Additional Technical Assistance studies*	A Technical Assistance (TA) study analyzes potential EE opportunities at a facility and can provide the customer a multi-year EE roadmap, generating savings for multiple years.	$209,483

*These initiatives are likely to result in some incentive spend in the current year, but the amounts for these items only include the Sales, Technical Assistance, and Training ("STAT") costs.
**The amounts for these initiatives include both STAT and incentive costs.

Record Request No. 3

Request:

RR-3 For each year in Exhibit PUC-5 (2010-2022), please provide what the earned electric and earned gas incentive would amount to in basis points on the return on equity on the Company's electric and gas distribution rate base for that corresponding year.

Response:

Please refer to Lines 6 and 10 on Page 1 of Attachment 1 to this response.

Prepared by or under the supervision of: Melissa Little

The Narragansett Electric Company
Rhode Island Energy Efficiency 2010-2022
EE Program Shareholder Incentives
$(000)
Basis Points on the return on equity on the Company's electric and gas distribution rate base

	Program Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Average 2010~ 2020
2	Performance Incentive Rate (% of Budget)	4.4%	4.4%	4.4%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	N/A	N/A	
3	Target Electric Incentive	$1.27	$1.99	$2.43	$3.24	$4.03	$3.87	$3.88	$4.43	$4.44	$4.91	$5.05	$5.50	$5.50	
4	Earned Electric Incentive	$1.33	$1.93	$2.47	$3.00	$4.22	$4.53	$4.13	$4.83	$4.94	$3.29	$3.24	$5.05	$0.00	
5	Target Electric Incentive as Basis Points of ROE	50.0	77.2	88.7	118.2	146.8	120.2	115.8	128.9	116.4	113.1	107.3	116.7	116.7	107.5
6	Earned Electric Incentive as Basis points of ROE	52.6	74.7	90.0	109.3	153.8	140.9	123.3	140.6	129.7	75.9	68.8	107.1	-	105.4
7	Target Gas Incentive	$0.20	$0.27	$0.57	$0.90	$1.09	$1.12	$1.25	$1.39	$1.31	$1.46	$1.58	$1.70	$1.70	
8	Earned Gas Incentive	$0.23	$0.24	$0.59	$0.97	$1.36	$1.39	$1.50	$1.63	$1.54	$1.58	$0.35	$1.30	$0.00	
9	Target Gas Incentive as Basis Points of ROE	13.7	17.3	32.9	44.4	46.0	40.3	41.3	40.9	33.1	33.1	31.2	33.6	33.6	34.0
10	Earned Gas Incentive as Basis points of ROE	15.8	15.1	33.8	47.9	57.6	49.9	49.3	48.1	39.0	35.9	6.9	25.7	-	36.3

Line Notes:

2 Target incentive is calculated in the same way as in 2021 in order to provide a more accurate estimate of the energy efficiency surcharge.
3 Line 5 of Page 2
4 Line 6 of Page 2
5 Page 2, Line 16
6 Page 2, Line 17
7 Line 5 of Page 3
8 Line 6 of Page 3
9 Page 3, Line 17
10 Page 3, Line 18

Table E-10 - PROVISIONAL PLAN - Refiled 11-5-2021
National Grid
Rhode Island Energy Efficiency 2010-2022
Energy Efficiency Incentives Equated to Basis Points of Return on Equity - Electric Business

	Electric	2010	2011	2012	2013(4)	2014	2015	2016	2017	2018	2019	2020(5)	2021(6)	2022(x)
1	Energy Efficiency Budget ($Million)(1)	$37.6	$59.2	$61.4	$77.5	$87.0	$86.6	$87.5	$94.6	$94.6	$107.5	$111.1	$116.8	$122.6
2	Spending Budget ($Million)(2)	$28.8	$45.3	$55.3	$64.8	$80.6	$77.3	$77.6	$88.5	$88.7	$98.1	$101.1	$104.8	$102.7
3	Actual Expenditures ($Million)(3)	$29.7	$40.0	$50.7	$72.9	$85.3	$87.4	$78.4	$94.8	$93.0	$100.7	$88.2		
4	Incentive Percentage(10)	4.4%	4.4%	4.4%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	N/A	N/A
5	Target Incentive(11)	$1,267,043	$1,992,513	$2,434,131	$3,240,747	$4,032,000	$3,867,400	$3,878,087	$4,425,528	$4,436,022	$4,905,009	$5,054,448	$5,500,000	$5,500,000
6	Earned Incentive	$1,333,996	$1,929,273	$2,469,411	$2,997,681	$4,223,321	$4,533,360	$4,128,034	$4,829,847	$4,940,402	$3,290,237	$3,242,675	*$5,047,043*	
7	Annual Summer Demand kW Savings Goal Achieved (%)	78%	71%	83%	114%	78%	112%	101%	103%	116%	98%	79%		
8	Annual MWh Energy Savings Goal Achieved (%)	107%	94%	93%	99%	105%	115%	107%	115%	110%	98%	88%		
9	Energy Efficiency Program Charge ($/kWh)(7)	$0.00320	$0.00526	$0.00592	$0.00876	$0.00911	$0.00953	$0.01077	$0.01124	$0.00972	$0.01121	$0.01323	$0.01113	$0.01426
10	Annual Cost to 500 kWh/month Residential Customer w/o tax(8)	$19.20	$31.56	$35.52	$52.56	$54.66	$57.18	$64.62	$67.44	$58.32	$67.26	$79.38	$66.78	$85.56
11	Annual Cost to 500 kWh/month Residential Customer w/ tax(9)	$20.00	$32.88	$37.00	$54.75	$56.94	$59.56	$67.31	$70.25	$60.75	$70.06	$82.69	$69.56	$89.13

12	Per annual Electric earnings reports for the 12 months ended:	Dec-2010	Dec-2011	Dec-2012	Dec-2013	Dec-2014	Dec-2015	Dec-2016	Dec-2017	Dec-2018	Dec-2019	Dec-2020	Dec-2021	Dec-2022
13	Average rate base	$ 592,888,677	$ 529,235,977	$ 562,467,734	$ 558,376,556	$ 558,965,340	$ 654,762,082	$ 681,283,839	$ 698,889,355	$ 747,835,132	$ 850,893,253	$ 924,621,273	$ 924,621,273	$ 924,621,273
14	Equity component percentage	42.75%	48.78%	48.78%	49.11%	49.14%	49.14%	49.14%	49.14%	50.95%	50.95%	50.95%	50.95%	50.95%
15	Equity rate base	$ 253,459,909	$ 258,161,310	$ 274,371,761	$ 274,218,727	$ 274,675,568	$ 321,750,087	$ 334,782,878	$ 343,434,229	$ 381,022,000	$ 433,530,112	$ 471,094,539	$ 471,094,539	$ 471,094,539
16	Target Incentive as Basis Points of ROE	50.0	77.2	88.7	118.2	146.8	120.2	115.8	128.9	116.4	113.1	107.3	116.7	116.7
17	Earned Incentive as Basis points of ROE	52.6	74.7	90.0	109.3	153.8	140.9	123.3	140.6	129.7	75.9	68.8	107.1	

Notes:

(1) Energy Efficiency Budget includes total expenditures and commitments. Includes all demand side management program-related expenses, including rebates, administration and general expenses, evaluation, commitments for future years and Company incentive.

(2) Prior to 2017, Spending Budget Eligible for Shareholder Incentive includes: Implementation, Administration, General, and Evaluation Expenses; excludes EERMC and OER Costs, Commitments, Copays, and Outside Finance Costs. Beginning in 2017, Outside Finance Costs were also included. Beginning in 2018 Pilot expenses were also excluded. Beginning in 2019 ConnectedSolutions expenses and assessments were also excluded.

(3) Actual Expenditures is actual spend during calendar year. Includes expenditures and commitments. Includes all demand side management program-related expenses, including rebates, administration and general expenses, evaluation, commitments for future years and Company incentive.

(4) In the Company's gas and electric rate cases in docket 4323, the PUC approved the uncollectibles gross-up in the electric EE Program Charge effective February 1, 2013, and a new rate applicable to the gross-up of the gas EE Program Charge, effective February 1, 2013.

(5) 2021 values are planned.

(6) 2022 values are proposed.

(7) Beginning in 2012, the EE Program Charge includes the System Reliability Factor. It does not include the $0.0003 renewables per RI General Laws §39-2-1.2 and Order #19608, which appears on customer bills.

(8) Reflects the annual cost excluding Gross Earnings Tax.

(9) Reflects the annual cost including Gross Earnings Tax.

(10) Incentive percentage not applicable for 2021 due to new performance incentive mechanism developed for the 2021 Annual Plan. See Section 11 of the Main Text of the 2022 Annual Plan for additional details.

(11) Target incentive is calculated in the same way as in 2021 in order to provide a more accurate estimate of the energy efficiency surcharge.

Line Notes:

15 Line 13 × Line 14
16 Line 5 ÷ Line 15 × 10,000
17 Line 6 ÷ Line 15 × 10,000

Table G-10 - PROVISIONAL PLAN - Refiled 11-5-2021
National Grid
Rhode Island Energy Efficiency 2010-2022
Energy Efficiency Incentives Equated to Basis Points of Return on Equity - Gas Business

	Gas	2010	2011(5)	2012	2013(6)	2014	2015	2016	2017	2018	2019	2020(7)	2021(8)	2022(s)
1	Energy Efficiency Budget ($Million)(1)	$4.8	$7.3	$13.7	$19.5	$23.5	$24.5	$27.7	$29.7	$28.1	$31.6	$34.3	$35.0	$36.7
2	Spending Budget ($Million)(2)	$4.5	$6.2	$12.9	$17.9	$21.8	$22.4	$25.0	$27.8	$26.2	$29.2	$31.6	$32.4	$33.6
3	Actual Expenditures ($Million)(3)	$5.5	$4.9	$13.3	$19.6	$21.5	$21.5	$24.6	$29.1	$28.8	$29.5	$24.6		
4	Incentive Percentage(12)	4.4%	4.4%	4.4%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	NA	NA
5	Target Incentive	$199,743	$274,460	$570,382	$898,285	$1,089,700	$1,119,800	$1,251,654	$1,387,550	$1,309,076	$1,460,570	$1,578,601	$1,700,000	$1,700,000
6	Earned Incentive	$231,310	$239,863	$586,036	$968,229	$1,362,108	$1,387,079	$1,496,869	$1,633,531	$1,541,255	$1,580,119	$347,732	*$1,300,000*	
7	Annual MMBtu Energy Savings Goal Achieved (%)	127%	117%	99%	109%	124%	111%	106%	113%	120%	104%	71%		
8	System Benefits Charge ($/therm) - all non-exempt custoemrs(11)	$0.0150	$0.0411	$0.0384	$0.0417									
9	Residential System Benefits Charge					$0.0600	$0.0781	$0.0748	$0.0888	$0.0869	$0.0715	$0.1011	$0.0871	$0.1221
10	C&I System Benefits Charge					$0.0492	$0.0637	$0.0487	$0.0726	$0.0671	$0.0420	$0.0704	$0.0596	$0.0836
11	Annual Cost to 846 Therm/year Residential Customer w/o tax(9)	$12.69	$12.69	$18.28	$32.49	$35.28	$50.76	$66.07	$63.28	$75.12	$73.52	$60.49	$85.53	$73.69
12	Annual Cost to 846 Therm/year Residential Customer w/tax(10)	$13.08	$13.08	$18.85	$33.49	$36.37	$52.33	$68.11	$65.24	$77.44	$75.79	$62.36	$88.18	$75.97

													proxy	*proxy*
13	Per annual Gas earnings reports for the 12 months ended:	Jun 2011	Jun 2012	Mar 2013	Mar 2014	Mar 2015	Mar 2016	Mar 2017	Mar 2018	Dec 2018	Dec 2019	Dec 2020	Dec 2020	Dec 2020
14	Average rate base	$ 305,905,137	$ 331,936,373	$ 361,679,538	$ 411,635,528	$ 481,554,946	$ 565,987,807	$ 617,312,160	$ 690,602,807	$ 776,357,063	$ 865,035,866	$ 993,192,574	$ 993,192,574	$ 993,192,574
15	Equity component percentage	47.71%	47.71%	47.95%	49.14%	49.14%	49.14%	49.14%	49.14%	50.95%	50.95%	50.95%	50.95%	50.95%
16	Equity rate base	$ 145,947,341	$ 158,366,844	$ 173,425,338	$ 202,277,698	$ 236,636,100	$ 278,126,408	$ 303,347,195	$ 339,362,219	$ 395,553,924	$ 440,735,774	$ 506,031,616	$ 506,031,616	$ 506,031,616
17	Target Incentive as Basis Points of ROE	13.7	17.3	32.9	44.4	46.0	40.3	41.3	40.9	33.1	33.1	31.2	33.6	33.6
18	Earned Incentive as Basis points of ROE	15.8	15.1	33.8	47.9	57.6	49.9	49.3	48.1	39.0	35.9	6.9	25.7	

Notes:

(1) Energy Efficiency Budget includes total expenditures and commitments. Includes all demand side management program-related expenses, including rebates, administration and general expenses, evaluation, commitments for future years and Company incentive.
(2) Prior to 2017, Spending Budget Eligible for Shareholder Incentive includes: Implementation, Administration, General, and Evaluation Expenses; excludes EERMC and OER Costs, Commitments, Copays, and Outside Finance Costs. Beginning in 2017, Outside Finance Costs were also included. Beginning in 2018 Pilot expenses were also excluded. Beginning in 2019 ConnectedSolutions expenses and assessment were also excluded.
(3) Actual Expenditures is actual spend during calendar year. Includes expenditures and commitments. Includes all demand side management program-related expenses, including rebates, administration and general expenses, evaluation, commitments for future years and Company incentive.
(4) Gas programs began during July 2007 and were not reported on separately that year since programs were still in development. The 2007 gas programs are included in 2008 reporting. Systems Benefit Charge shown for 2007 is the weighted average of $0.063 per decatherm from January 1, 2007 - June 30, 2007 and $0.107 per decatherm from July 1, 2007 through December 31, 2008.
(5) On July 25, 2011 the Commission ordered that National Grid could increase the gas System Benefits Charge from $0.15 to $0.411 per decatherm for the period of August 1, 2011 through December 31, 2011. Annual cost represents 7 months usage (632 therms) at $0.015 per therm and 5 months usage (214 therms) at $0.0411 per therm.
(6) In the Company's gas and electric rate cases in docket 4323, the PUC approved the uncollectibles gross-up in the electric EE Program Charge effective February 1, 2013, and a new rate applicable to the gross-up of the gas EE Program Charge, effective February 1, 2013.
(7) 2021 values are planned.
(8) 2022 values are proposed.
(9) Reflects the annual cost excluding Gross Earnings Tax.
(10) Reflects the annual cost including Gross Earnings Tax.
(11) The Gas EE Program Charge was uniform for all customers until 2014, at which time the Company proposed and the PUC approved individual factors for the residential and C&I sectors.
(12) Incentive percentage not applicable for 2022 due to new performance incentive mechanism developed for the 2022 Annual Plan. See Section 11 of the Main Text of the 2022 Annual Plan for additional details.

Line Notes:

13 Historical Gas earnings reports have reflected differing 12-month periods persuant to Docket Nos. 3401, 3943, 4323 and 4770.
16 Line 14 × Line 15
17 Line 5 ÷ Line 16 × 10,000
18 Line 6 ÷ Line 16 × 10,000

Record Request No. 4

Request:

RR-4 - Please provide a corrected Section 10.4 of the Company's proposed 2022 Annual Energy Efficiency Plan (Bates 121 – 122) that reflects the Company's intent as testified to at the evidentiary hearing on December 8, 2021.

Response:

Please see a redlined Section 10.4 reflecting the corrections. (Deleted language is red and struck through. There was no additional language added.)

10.4 Transferring Funds

Continuing from the approved notifications approved as part of the 2021 plan, the Company proposes the following guidelines for transfers between programs. The Company and stakeholders will regularly review the amount of funds needed and available for each program (as well as any changes to the overall fund balance discussed above) and will transfer monies as needed. Transfers during the program year may occur as follows:

- Transfers within a Sector. For transfers of less than 20% of the originating program's budget, the Company can transfer funds from one program to another program or pilot in the same sector. For transfers of 20% or more of the originating program or pilot's budget, the Company can transfer funds from one program to another program in the same sector with the Division's prior approval. Upon seeking the Division's approval, the Company shall simultaneously notify the EERMC and OER. For all transfers in a sector, the Company will reflect changes in the quarterly report(s) following the transfer and the year-end report.

- Transfers between Sectors. The Company can transfer funds from one sector to another sector with the Division's prior approval. Upon seeking the Division's approval, the Company shall simultaneously notify the EERMC and OER. If a transfer reduces the originating sector's budget by more than 20% in aggregate over the course of the program year, the transfer will also require PUC approval. For all transfers between sectors, the Company will reflect changes in the quarterly report(s) following the transfer and the year-end report.

Prepared by or under the supervision of: John Tortorella and John Richards

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- Transfers among residential retrofit programs. The Company can transfer among Energy*Wise*, Multifamily, Income Eligible Multifamily, and C&I Multifamily (which are in different sectors) programs in order to achieve the overall savings goals of all programs. Although these are listed as separate lines in the program tables, they are essentially one program from an implementation standpoint. For all transfers between residential retrofit programs, the Company will reflect changes in the quarterly report(s) following the transfer and the year-end report.

- For transfers requiring Division and/or EERMC, but not PUC approval, the Company will inform the PUC of the transfers, both between sectors and within sectors, in a timely fashion.

- The Company will not be permitted to adjust its goals or incentive target calculations as a result of any transfers between sector budgets. Any changes will be communicated and reported consistent with transfers between sectors, described above.

Prepared by or under the supervision of: John Tortorella and John Richards

Record Request No. 5

Request:

RR-5 – Please provide a copy of the Avoided Energy Supply Components in New England: 2021 Report ("2021 AESC Study"). Please also separate and specifically include a copy of Table ES-4 of the 2021 AESC Study.

Response:

Attachment RR-5 is a copy of the Avoided Energy Supply Components in New England: 2021 Report ("2021 AESC Study.") The study can also be downloaded on the Synapse Energy Economics website.[1]

Table ES-4 (page 8 of the 2021 AESC Study) is below.

[1] https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf

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ES-Table 4. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #4 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		Notes
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.22	-0.89	-42%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.90	-1.42	-27%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.40	0.98	237%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.52**	**-1.33**	**-17%**	
GHG non-embedded	**2.69**	**2.83**	**4.69**	**1.86**	**66%**	*5,10*
NO_x non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.21	-0.98	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.62**	**-1.60**	**-50%**	-
Total	**15.68**	**16.49**	**14.94**	**-1.54**	**-9%**	-

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $50/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $13/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

Avoided Energy Supply Components in New England: 2021 Report

Prepared for AESC 2021 Study Group

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AMENDMENTS TO THE AESC 2021 STUDY

This is the second public release of the AESC 2021 Study. This document updates and amends the version originally released on March 15, 2021. The following text summarizes these changes.

- Text in Chapter 12: *Sensitivity Analysis* is now populated. Corresponding text was added to the executive summary (in the subsection titled "Sensitivities").
- We updated text in Chapter 2: *Avoided Natural Gas Costs* related to the calculation of the medium-term Henry Hub natural gas price forecast. Text in the March 15 edition referred to a methodology used in earlier drafts. This text has now been updated to reflect our final methodology. We also modified text in the natural gas section of the Executive Summary to reflect this update. We note that these are changes to the text only; all of the modeled avoided costs are unchanged.
- We clarified which avoided transmission and distribution (T&D) costs are included in summary tables like ES-Table 1. These tables only included avoided T&D costs related to pooled transmission facilities (PTF) and do not include non-PTF avoided T&D costs or avoided costs related to local T&D systems.
- We made a cosmetic correction to the Y-axis in Figure 17.
- In Section 8.1. *Non-embedded GHG costs*, the paragraph that begins with "In AESC 2018, the cost of avoided CO_2 was reported to be $68 per short ton…" was edited for clarity.
- We corrected a typographical error in Table 56 so that the "CES-E" program correctly refers to Massachusetts, rather than Maine.
- Numbering of figures, tables, footnotes, and pages has changed due to the inclusion of new text in Chapter 12: *Sensitivity Analysis* and other edits throughout the document.
- We have corrected a formula error in each of the AESC 2021 User Interface workbooks, on the sheet named "NonEmbedded_Calcs." In practical terms, this increases the non-embedded GHG cost for Vermont (assuming a New England marginal abatement cost-basis) by 1 percent. There are no other changes to other regions. No updates were required to tables or text in this document.

There are no further amendments, notes, or errata at this time.

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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	U.S. 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
LDC	Local distribution company
LMP	Locational marginal price
LNG	Liquefied natural gas
LSE	Load-serving entity
MMcf	Million cubic feet
Net ICR	Net installed capacity requirement
PTF	Pool transmission facilities
REC	Renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable natural gas
RPS	Renewable portfolio standard
VoLL	Value of lost load

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1. EXECUTIVE SUMMARY

This document is the 2021 Avoided Energy Supply Component (AESC) Study (AESC 2021). AESC 2021 contains cost streams 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 AESC Study provides estimates of avoided costs associated with energy efficiency measures for program administrators 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 the New England program administrators do not install any new demand-side measures in 2021 or later years. New to this year's study, AESC 2021 features four different counterfactuals:

- **Counterfactual #1:** A future in which program administrators install no new energy efficiency, building electrification, or active demand management (demand response and energy storage) resources in 2021 or later years.
- **Counterfactual #2:** A future in which program administrators install no new building electrification resources in 2021 or later years. This future does model some amount of energy efficiency and active demand management resources installed by the program administrators.
- **Counterfactual #3:** A future in which program administrators install no new energy efficiency resources in 2021 or later years. This future does model some amount of building electrification and active demand management resources installed by the program administrators.
- **Counterfactual #4:** A future in which program administrators install no new energy efficiency resources in 2021 or later years. This future does model some amount of building electrification installed by the program administrators but does not include any active demand management resources installed by the program administrators.

Because each AESC counterfactual represents a hypothetical future that lacks some amount of anticipated demand-side measures, AESC 2021 should not 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 since 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 AESC 2021 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). Also, AESC 2021 relies upon a combination of models to estimate each one of these avoided costs for each future year. As in AESC 2018, this study provides avoided energy costs on an hourly basis. This allows 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. Other avoided costs (e.g., natural gas, fuel oil) are provided at the time resolutions that are most appropriate for their markets (e.g., daily, seasonal, or annual).

On a 15-year levelized basis, in real 2021 dollars, the AESC 2021 Study estimates that direct avoided retail energy costs are approximately 4 cents per kWh for Counterfactual #1, and direct avoided gas costs are $6 per MMBtu, although these vary on the specific location and end-use. Compared to 2018 AESC, we find:

- Generally lower avoided costs of energy, due to sustained low natural gas prices at national hubs, lower estimated costs of complying with the Regional Greenhouse Gas Initiative (RGGI), and increased quantities of zero-marginal-cost renewables.
- Generally lower avoided costs of capacity due to a relatively flat supply curve based on observations of recent forward capacity auctions.
- Generally lower avoided costs of natural gas, based on lower long-term projections of wholesale natural gas prices. Avoided natural gas costs for retail end-users are also lower than in AESC 2018; but because incremental gas pipeline expansion costs are assumed to be higher, the change in avoided costs at the end-user level is not as large as the reduction in gas commodity prices.
- Generally higher avoided costs for fuel oil and other fuels, due to updates to recent historical data in the underlying sources in the sources used to calculate these values.
- Generally higher avoided costs for renewable portfolio standard (RPS) compliance. This is primarily due to recent (or anticipated) increases in RPS target obligations combined with expected increases in load due to electrification.
- Lower energy DRIPE and capacity DRIPE values, due to changes in utility long-term energy purchases, updated market data, and new commodity forecasts. Natural gas DRIPE and oil DRIPE values are also lower due to similar changes.
- Both higher and lower non-embedded costs for environmental regulations that are not otherwise included in the above projections (e.g., carbon dioxide, CO_2, and nitrogen oxides, NO_X) depending on the approach used to calculate this number. AESC 2021 presents a number of different non-embedded costs for use in different state policy contexts.
- Lower avoided costs for pooled transmission facility (PTF) costs, as a result of a switch to a forward-looking methodology (AESC 2018 utilized a historical methodology). AESC 2021 also presents additional methodologies for quantifying localized and non-PTF transmission and distribution avoided costs.
- Generally lower avoided costs for reliability, due to a flatter supply capacity market supply curve. This is in spite of a higher estimate for value of lost load (VoLL), determined through newly available data sources.

AESC 2021 provides detailed projections of avoided costs by year for an initial 15-year period based on modeling (2021 through 2035), and a second period based on extrapolation of values from this first period (2036 through 2055).[1] All values in this document are described in terms of real 2021 dollars, unless noted otherwise. In many cases, we provide 15-year (2021–2035) levelized values of avoided costs for ease of reporting and comparison with earlier AESC studies. See Appendix E: *Common 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 AESC 2021 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 AESC 2021 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: Acadia Center, Connecticut Department of Energy and Environmental Protection, Connecticut Energy Efficiency Board, Maine Public Utilities Commission, Massachusetts Energy Efficiency Advisory Council, Massachusetts Clean Energy Center, Massachusetts Department of Public Utilities, Massachusetts Department of Energy Resources, Massachusetts Department of Environmental Protection, Massachusetts Attorney General, Massachusetts Low-Income Energy Affordability Network (LEAN), New Hampshire Office of Consumer Advocate, New Hampshire Public Utilities Commission, Rhode Island Division of Public Utilities and Carriers, Rhode Island Energy Efficiency and Resource Management Council, Rhode Island Office of Energy Resources, Vermont Department of Public Service, and Vermont Energy Investment Corporation / Efficiency Vermont.

After developing the scope for the 2021 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 Synapse Team).

[1] This extrapolation is described in detail in Appendix A: *Usage Instructions*.

1.2. Summary of avoided costs

The following section provides a summary of the avoided costs for each category of costs calculated under the AESC 2021 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 summer on-peak avoided cost components for electricity for the West/Central Massachusetts (WCMA) zone for Counterfactual #1, and how these components compare to the avoided costs from the previous AESC 2018 study for informational purposes. ES-Table 2, ES-Table 3, and ES-Table 4 provide analogous comparative information for Counterfactuals #2, #3, and #4, respectively.

In general, the Synapse Team finds that lower wholesale natural gas prices drive lower avoided energy costs, relative to AESC 2018. We also find that avoided cost of RPS compliance in AESC 2021 are generally higher than those projected in AESC 2018. This is primarily due to recent (or anticipated) increases in RPS target obligations combined with expected increases in load due to electrification). We find that projections of flatter supply curves in future years cause avoided capacity, energy DRIPE, and capacity DRIPE values to be lower.

Note that comparisons between 15-year levelized costs in AESC 2021 and AESC 2018 are not directly “apples-to-apples.” While both calculations display levelized costs over 15 years (in real 2021 dollars), each levelization calculation is done over two different 15-year periods (2018 to 2032 for AESC 2018, and 2021 to 2035 for AESC 2021). 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.

ES-Table 1. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #1 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		Notes
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.18	-0.93	-44%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.85	-1.48	-28%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.28	0.86	208%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.30**	**-1.55**	**-20%**	
GHG non-embedded	**2.69**	**2.83**	**4.74**	**1.91**	**67%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.20	-0.99	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.61**	**-1.60**	**-50%**	**-**
Total	**15.68**	**16.49**	**14.77**	**-1.72**	**-10%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $49/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $12/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

ES-Table 2. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #2 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		Notes
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.16	-0.95	-45%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.63	-1.69	-32%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	0.98	0.56	136%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**5.77**	**-2.08**	**-26%**	
GHG non-embedded	**2.69**	**2.83**	**5.08**	**2.25**	**79%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-33%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.39	-0.64	-62%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.08	-1.11	-51%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.47**	**-1.75**	**-54%**	**-**
Total	**15.68**	**16.49**	**14.43**	**-2.05**	**-12%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $48/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $31/MWh
9. Avoided RPS compliance cost of $9/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.46/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

ES-Table 3. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #3 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		*Notes*
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.22	-0.88	-42%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.92	-1.40	-26%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.40	0.98	237%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.54**	**-1.31**	**-17%**	
GHG non-embedded	**2.69**	**2.83**	**4.68**	**1.85**	**65%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.21	-0.98	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.62**	**-1.60**	**-50%**	**-**
Total	**15.68**	**16.49**	**14.96**	**-1.52**	**-9%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $51/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $13/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

ES-Table 4. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 Counterfactual #4 versus AESC 2018

	AESC 2018	AESC 2018	AESC 2021	AESC 2021, relative to AESC 2018		Notes
	2018 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	2.00	2.11	1.22	-0.89	-42%	*3,4,5,6*
Avoided Retail Energy Costs	5.05	5.32	3.90	-1.42	-27%	*5,7,8*
Avoided RPS Compliance	0.39	0.41	1.40	0.98	237%	*5,7,9*
Subtotal: Capacity and Energy	**7.48**	**7.85**	**6.52**	**-1.33**	**-17%**	
GHG non-embedded	**2.69**	**2.83**	**4.69**	**1.86**	**66%**	*5,10*
NO_X non-embedded	**0.18**	**0.19**	**0.08**	**-0.11**	**-55%**	*5*
Transmission & Distribution (PTF)	**2.26**	**2.38**	**2.02**	**-0.36**	**-15%**	*3,5,11*
Value of Reliability	**0.02**	**0.02**	**0.01**	**-0.01**	**-32%**	*3,5,6,12*
Electric capacity DRIPE	0.97	1.03	0.41	-0.62	-60%	*5,6*
Electric energy and cross-DRIPE	2.08	2.19	1.21	-0.98	-45%	*5,7,13*
Subtotal: DRIPE	**3.05**	**3.22**	**1.62**	**-1.60**	**-50%**	**-**
Total	**15.68**	**16.49**	**14.94**	**-1.54**	**-9%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars unless otherwise stated.
2. AESC 2018 data is from ES-Table 1 in AESC 2018. AESC 2018 values levelized (2018-2032) escalated with a factor of 1.05 to convert 2018 dollars to 2021 dollars. We observe that the total cost in AESC 2018 was 16.05 cents per kWh in 2018 dollars or 16.91 cents per kWh in 2021 dollars.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2018 cost (2018 $/kW-year) of $83/kW-year
AESC 2021 cost (2021 $/kW-year) of $50/kW-year
5. Includes T&D loss adjustments of:
9.0% for energy
16.0% for peak demand
These adjustments are also applied to AESC 2018 values, some of which used an 8% T&D loss factor in that study's ES-Table 1
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh
9. Avoided RPS compliance cost of $13/MWh
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year. This value does not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. In both AESC 2018 and AESC 2021, these DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

Natural gas

At a high level, AESC 2021 assumes that Henry Hub natural gas prices are lower, and stay lower longer, relative to the assumptions used in AESC 2018. The levelized price basis for the New England market, as measured by the Algonquin Citygate price, is also lower.

On a 15-year levelized basis (see ES-Table 5), AESC 2021 projects a Henry Hub price of $3.15 per MMBtu (levelized over 2021 to 2035), 34.0 percent lower than the AESC 2018 value of $4.78 per MMBtu (levelized over 2018 to 2032). We attribute the decrease in Henry Hub prices to higher volumes of 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 2018.[2] Breakeven costs have been on a downward trend as a result of improvements in horizontal drilling technology and better information on the geology and geophysics of shale reservoirs.[3] Algonquin Citygate Hub prices show a slightly larger decline because the basis projections are lower in AESC 2021 (a smaller differential to Henry Hub) as a result of additional pipeline capacity and changing pricing dynamics between northeast and Gulf Coast gas markets.

ES-Table 5. Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials for AESC 2021 and AESC 2018

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2018 (2018–2032)	2021 $/MMBtu	$4.78	$6.59	$1.24
AESC 2021 (2021–2035)	2021 $/MMBtu	$3.15	$4.20	$1.05
Percent change	%	-34.0%	-36.2%	-

Notes: All values are in 2021 $/MMBtu. AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2018 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

The avoided costs of natural gas for retail customers are summarized below (see ES-Table 6). For both southern New England and northern New England avoided natural gas costs are lower in AESC 2021 compared to AESC 2018, but because pipeline expansion costs are assumed to be higher, the change in avoided costs is not as large as the reduction in wholesale commodity prices. Northern New England avoided costs remain slightly lower relative to southern New England because 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 6) avoided natural gas costs are also lower than in AESC 2018 because of lower projected natural gas prices at the Dawn Hub.

[2] Associated gas is essentially a byproduct in the production of crude oil. This gas will be produced (or flared) as long as oil production is economic, irrespective of the price of natural gas.

[3] U.S. Energy Information Administration (EIA). "Drilling Productivity Report." https://www.eia.gov/petroleum/drilling/. February 16, 2021.

ES-Table 6. Avoided costs of gas for all retail customers by end-use assuming no avoidable margin

	Units	Southern New England	Northern New England
AESC 2018 (2018–2032)	2021 $/MMBtu	$7.91	$7.57
AESC 2021 (2021–2035)	2021 $/MMBtu	$6.48	$6.39
Percent change	%	-18%	-16%

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 0:

Avoided Natural Gas Costs.

ES-Table 8 compares the natural gas avoided costs described in ES-Table 6 with a non-embedded cost for GHGs. For consistency with ES-Table 1 and other similar tables, the non-embedded GHG cost shown here is the marginal abatement cost derived from the New England electric sector. We observe that the non-embedded GHG cost is roughly equal to the avoided cost of natural gas, which matches our observations in ES-Table 1, where the non-embedded cost is slightly greater than the avoided cost of energy.

ES-Table 7. Avoided costs of gas, with and without non-embedded GHG cost

	Units	Southern New England	Northern New England
Avoided cost (from ES-Table 6)	2021 $/MMBtu	$6.48	$6.39
Non-embedded GHG cost	2021 $/MMBtu	$7.32	$7.32
Avoided cost with non-embedded GHG cost	2021 $/MMBtu	$13.80	$13.71

Note: Avoided costs differ depending on region, and whether or not retail margins are included. The "non-embedded GHG cost" shown here is the marginal abatement cost derived from the New England electric sector.

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 2018, except for the levelized costs for commercial residual fuel oil and biofuels which are lower than was estimated in AESC 2018. The primary sources of these differences are changes in historical prices from the State Energy Data System (SEDS) and changes in the projected price of crude oil, which underlies many of the cost projections. ES-Table 8 displays the levelized avoided fuel costs for AESC 2021. New in AESC 2021 are avoided cost projections for motor gasoline and motor diesel.

ES-Table 8. Avoided costs of retail fuels (15-year levelized, 2021 $ per MMBtu)

	Residential						Commercial		Transportation	
	No. 2 Distill-ate	Pro-pane	Kero-sene	Bio-Fuel (B20)	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Resid-ual	Motor Gasoline	Motor Diesel
AESC 2018	$23.36	$32.78	$20.95	$24.06	$14.12	$22.76	$19.46	$17.13	-	-
AESC 2021	$24.04	$38.79	$29.59	$21.64	$20.84	$22.47	$22.25	$15.74	$22.07	$22.76
Percent change	2.9%	18.3%	41.3%	-10.1%	47.6%	-1.3%	14.3%	-8.2%	-	-

The retail fuels avoided costs for AESC 2021 are similar to those of AESC 2018 for distillate fuels. The more significant differences between AESC 2021 and AESC 2018 observed in other fuels are primarily driven by changes in the starting prices based on recent historical data. There have been significant residential price increases for propane in recent years, perhaps associated with distribution costs. For non-wood products, AESC 2021 starts with the 2018 New England fuel prices in the U.S. Energy Information Administration (EIA) State Energy Data System (SEDS). It then makes adjustments to match the most recent national prices from the EIA Short Term Energy Outlook (STEO). For the near term, fuel oil prices follow the STEO's crude oil price forecast for 2021. Meanwhile, for 2022 and later years, we rely on projections in the AEO 2021 Reference case. For biofuels, the B20 blend shown in the table is discounted at about 10 percent below distillate. All sector propane prices are consistently higher than distillate prices for all years in SEDS.

For residential wood fuels, AESC 2021 surveyed various state energy sources, which gave much higher cord wood prices than those used in AESC 2018. Wood pellet prices were however about the same. Wood prices are then projected to increase in the future following the trend in crude oil prices reflecting competitive market factors.

Capacity

AESC 2021 develops capacity prices for annual commitment periods starting in June 2021 under each of the four counterfactuals (see ES-Table 9). 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, Counterfactual #1 of the AESC 2021 forecast is 47 percent lower than what was estimated as a 15-year levelized price in the 2018 AESC study. Counterfactual #2 is 48 percent lower, while Counterfactual #3 and #4 are both 45 percent lower. In general, Counterfactual #2 has lower capacity prices due to a lower projection of load, while Counterfactuals #1, #3, and #4 feature relatively similar capacity prices, due to similar projections of annual loads. Market-clearing prices in the out-years are principally determined by future changes in supply (including additions of battery storage, solar, wind, and occasionally new natural gas-fired power plants; as well as and retirements of thermal generation) and future changes in demand. Small year-on-year variations are due to changes in load, new resources coming online, and other resources retiring.

ES-Table 9. AESC 2018 capacity prices (2021 $ per kW-month)

Commitment Period (June to May)	FCA	Actual	Actual but for post-2020 EE	AESC 2021 Counter-factual #1	AESC 2021 Counter-factual #2	AESC 2021 Counter-factual #3	AESC 2021 Counter-factual #4	AESC 2018
2021/2022	12	$4.63	$4.77	$4.77	$4.63	$4.77	$4.77	$4.99
2022/2023	13	$3.73	$3.96	$3.96	$3.73	$3.96	$3.96	$5.10
2023/2024	14	$1.92	$2.47	$2.47	$1.92	$2.47	$2.47	$5.21
2024/2025	15	$2.46	$2.75	$2.75	$2.46	$2.75	$2.75	$5.50
2025/2026	16			$2.72	$2.69	$2.59	$2.59	$5.95
2026/2027	17			$2.88	$2.69	$2.75	$2.75	$6.46
2027/2028	18			$3.11	$3.33	$3.46	$3.43	$6.95
2028/2029	19			$3.30	$3.30	$3.65	$3.62	$7.45
2029/2030	20			$3.59	$3.41	$3.94	$3.92	$7.95
2030/2031	21			$3.42	$3.77	$3.97	$3.94	$6.95
2031/2032	22			$3.67	$3.81	$3.79	$3.77	$7.45
2032/2033	23			$3.90	$3.86	$4.02	$3.99	$7.95
2033/2034	24			$3.86	$4.02	$3.95	$3.92	$6.95
2034/2035	25			$4.67	$4.47	$5.09	$4.95	$7.45
2035/2036	26			$3.66	$3.86	$3.73	$3.71	$7.95
15-year levelized cost				**$3.51**	**$3.45**	**$3.65**	**$3.63**	**$6.63**
Percent difference				**-47%**	**-48%**	**-45%**	**-45%**	

Notes: Levelization periods are 2021/2022 to 2035/2036 for AESC 2021 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 0.81 percent for AESC 2021 and 1.34 percent for AESC 2018.

Energy

AESC 2021 modeling results feature a lower ratio of summer peak prices to the annual average compared to previous AESC studies. This difference can be attributed to: (1) increased levels of solar generation, which are 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. These are the same factors that drove the change in energy prices in AESC 2015 and AESC 2018.

ES-Table 10 shows levelized costs (over 15 years) for the WCMA reporting region. Prices are shown for all hours, and for the four conventional AESC costing periods. On an annual average basis, the 15-year levelized prices in Counterfactual #1 of the AESC 2021 study are 20 percent lower than the prices modeled in the 2018 AESC study. Key drivers of these lower prices include lower Henry Hub natural gas prices, lower RGGI prices, 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. Energy prices observed in other counterfactuals are similar to Counterfactual #1. Counterfactual #2 features the largest divergence, as a result of its lower projection of load. This decrease is larger than the change in avoided energy costs observed between the 2015 AESC study and the 2018 AESC study.

ES-Table 10. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	$51.17	$58.66	$54.17	$45.22	$38.69
AESC 2021 Counterfactual 1	$40.85	$46.86	$45.20	$32.67	$29.86
AESC 2021 Counterfactual 2	$37.79	$42.98	$41.66	$30.87	$27.95
AESC 2021 Counterfactual 3	$41.34	$47.43	$45.63	$33.28	$29.93
AESC 2021 Counterfactual 4	$41.29	$47.40	$45.62	$33.17	$29.87
Pcnt Change: Counterfactual 1	-20%	-20%	-17%	-28%	-23%
Pcnt Change: Counterfactual 2	-26%	-27%	-23%	-32%	-28%
Pcnt Change: Counterfactual 3	-19%	-19%	-16%	-26%	-23%
Pcnt Change: Counterfactual 4	-19%	-19%	-16%	-27%	-23%

Notes: All prices have been converted to 2021 $ per MWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. Prices are wholesale.

ES-Table 11 compares 15-year levelized costs between AESC 2018 and AESC 2021 for each of the six New England states, for Counterfactual #1. These values incorporate the relevant costs of RPS compliance, as well as a wholesale risk premium.

ES-Table 11. Avoided energy costs, AESC 2021 vs. AESC 2018 (15-year levelized costs, 2021 $ per kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	1	Connecticut	$0.059	$0.057	$0.043	$0.040
	2	Massachusetts	$0.062	$0.060	$0.047	$0.044
	3	Maine	$0.057	$0.056	$0.042	$0.039
	4	New Hampshire	$0.058	$0.057	$0.043	$0.040
	5	Rhode Island	$0.065	$0.064	$0.050	$0.047
	6	Vermont	$0.054	$0.053	$0.039	$0.036
AESC 2018	1	Connecticut	$0.063	$0.059	$0.049	$0.043
	2	Massachusetts	$0.062	$0.058	$0.049	$0.043
	3	Maine	$0.058	$0.054	$0.045	$0.039
	4	New Hampshire	$0.063	$0.060	$0.051	$0.044
	5	Rhode Island	$0.061	$0.057	$0.048	$0.042
	6	Vermont	$0.062	$0.058	$0.049	$0.042
Delta	1	Connecticut	-$0.005	-$0.002	-$0.006	-$0.003
	2	Massachusetts	-$0.001	$0.003	-$0.002	$0.001
	3	Maine	$0.000	$0.002	-$0.003	$0.000
	4	New Hampshire	-$0.005	-$0.003	-$0.008	-$0.004
	5	Rhode Island	$0.003	$0.007	$0.002	$0.005
	6	Vermont	-$0.008	-$0.005	-$0.010	-$0.006
Percent Change	1	Connecticut	-7%	-3%	-12%	-7%
	2	Massachusetts	-1%	5%	-4%	2%
	3	Maine	0%	4%	-6%	1%
	4	New Hampshire	-8%	-5%	-15%	-8%
	5	Rhode Island	6%	12%	5%	12%
	6	Vermont	-13%	-8%	-20%	-14%

Notes: These costs are the sum of wholesale energy costs and wholesale costs of RPS compliance, increased by a wholesale risk premium of 8 percent, except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2021 dollars per kWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. Values do not include losses.

RPS compliance

Relative to AESC 2018, AESC 2021 sees much higher prices for meeting RPS compliance (see ES-Table 12). This difference is attributable to increased supply-demand tension in the near term, resulting in higher REC prices compared to AESC 2018, particularly for states that have recently adjusted their RPS policies. Even with higher prices, the remainder of the study period is characterized by surplus, with policy-mandated purchases exceeding incremental RPS demands. The cost of RPS compliance has also increased as a result of the addition of new RPS categories such as Clean Energy Standard-Existing (CES-E) and Clean Peak Energy Portfolio Standard (CPS) categories in Massachusetts. Increases in the cost of RPS compliance in states that have not increased RPS targets (e.g., New Hampshire) are due to an increase in REC demand in the New England-wide REC market, of which all six states are participants.

ES-Table 12. Avoided cost of RPS compliance (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
AESC 2018	$4.00	$0.55	$3.84	$5.25	$2.57	$2.12
AESC 2021 Counterfactual 1	$7.93	$7.37	$11.81	$8.10	$14.99	$3.90
AESC 2021 Counterfactual 2	$4.77	$3.55	$9.04	$6.41	$5.66	$2.67
AESC 2021 Counterfactual 3	$8.84	$8.56	$12.93	$8.67	$16.81	$4.44
AESC 2021 Counterfactual 4	$8.84	$8.56	$12.93	$8.67	$16.81	$4.44
Pcnt Change: Counterfactual 1	98%	1233%	208%	54%	482%	84%
Pcnt Change: Counterfactual 2	19%	541%	135%	22%	120%	26%
Pcnt Change: Counterfactual 3	121%	1448%	237%	65%	553%	110%
Pcnt Change: Counterfactual 4	121%	1448%	237%	65%	553%	110%

Note: Each state has multiple Classes or Tiers. For simplicity, we sum avoided costs for all non-Class I/New RPS policies together in the "all other classes" row. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. AESC 2018 values are from AESC 2018 Chapter 7, and have been converted into 2021 dollars. All values include a 9 percent loss factor.

Non-embedded environmental compliance

AESC 2021 provides several approaches to enable individual states to address specific policy directives regarding greenhouse gas (GHG) impacts. ES-Table 13 and ES-Table 14 compare these costs.

- A "damage cost" approximated by the social cost of carbon (SCC). There are many different options for a social cost of carbon. The Synapse Team recommends using a value that applies low discount rates, considers global damages, and considers the impact of high-risk situations. One source for this value is the December 2020 SCC Guidance published by the State of New York. Using a 2 percent discount rate (the one also recommended by New York for most decision-making), we recommend a 15-year levelized SCC of $128 per short ton in AESC 2021. We also recommend that program administrators continually review this value (e.g., for the purposes of mid-term modifications) as updates to the federally-recommended SCC are expected in early 2022.

- An approach based on global marginal abatement costs. In AESC 2021, we estimate a total environmental cost based on the cost of large-scale carbon capture and sequestration (CCS) equal to $92 per short ton of CO_2-eq. This is lower than the $105 per short ton of CO_2-eq value (in 2021 dollars) described in AESC 2018. This lower cost reflects the declining costs of this technology.

- An approach based on New England marginal abatement costs, assuming a cost derived from electric sector technologies. In AESC 2021, this is a total environmental cost of $125 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for offshore wind energy along the eastern seaboard. This compares to a cost of $72 per short ton of CO_2-eq emissions (in 2021 dollars) based on a projection of future costs of offshore wind energy, as described in AESC 2018. This increased cost reflects updated information on this technology in the United States, as well as lower energy costs in this edition of AESC.

- An approach based on New England marginal abatement costs, assuming a cost derived from multiple sectors. In AESC 2021, this is a total environmental cost of $493 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for renewable natural gas (RNG) derived from power-to-gas technology. This approach may be useful for policymakers who are considering more ambitious carbon reduction targets (e.g., 90 percent or 100 percent reductions by 2050).

ES-Table 13. Comparison of GHG costs under different approaches (2021 $ per short ton) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	$128	-	-
Global marginal abatement cost	$105	$92	-$13	-12%
New England-based marginal abatement cost, derived from the electric sector	$72	$125	$53	75%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	$493	-	-

Notes: All values shown are levelized over 15 years. All AESC 2021 values except the SCC are levelized using a 0.81 percent discount rate (SCC uses a 2.0 percent discount rate). All AESC 2018 values are levelized using a 1.34 percent discount rate, then converted into 2021 dollars. In AESC 2018, damage costs were discussed, but not quantified. AESC 2018 did not discuss or estimate a New England-based marginal abatement cost derived from multiple sectors. Values shown above remove energy prices, but not embedded costs. Values shown above do not include losses.

ES-Table 14. Comparison of GHG costs under different approaches (2021 cents per kWh) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	4.87	-	-
Global marginal abatement cost	4.64	3.41	-1.23	-26%
New England-based marginal abatement cost, derived from the electric sector	2.83	4.74	1.91	67%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	19.72	-	-

Notes: Values shown above remove embedded costs (e.g., RGGI, MA 310 7.74, MA 310 7.75. All values are quoted using a summer on-peak seasonal marginal emission rate, and include a 9 percent energy loss factor.

In addition, AESC 2021 establishes a non-embedded NO_X emission cost of $14,700 per short ton, based on a review of findings in the literature, which translates into an avoided wholesale cost for NO_X of $0.77 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 2021 models DRIPE benefits associated with reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets. DRIPE results in AESC 2021 differ from those in AESC 2018 because of updated information changes in utility long-term energy purchases, updated market data, and new commodity forecasts. Generally speaking, we find (a) lower energy DRIPE and capacity DRIPE values, due to projections of flatter supply curves compared to AESC 2018, (b) lower natural gas DRIPE values due to lower commodity prices and flatter supply curves, and (c) lower oil DRIPE values, due to changes in the underlying projection of crude oil prices.

Transmission and distribution

In AESC 2021, we present four separate threads for analysis of avoided transmission and distribution (T&D) costs, building on the foundation established in the 2018 AESC and updating or expanding the analysis presented. The four aspects are:

1. Updating the avoided costs for PTF facilities based on future costs;
2. Reviewing utility approaches to generic avoided cost values for non-PTF transmission and distribution and evaluating these approaches on a common evaluation rubric to facilitate cross-comparison and learning;
3. Reviewing utility approaches to calculating geographically localized avoided costs, such as for non-wire alternatives (NWA); and
4. Developing an approach to the avoided cost of natural gas system T&D.

Of these items, only the first was performed in AESC 2018. In that study, we found the PTF cost to be $99 per kW-year (in 2021 dollars). In AESC 2021, we find the PTF value to be $84 per kW-year, a decrease of 15 percent. This change is due to a switch to a forward-looking methodology, versus the historical cost methodology used in AESC 2018.

Reliability

As in AESC 2018, AESC 2021 examines how changing electric load levels can change 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 VoLL. We then develop estimates of the value of increased generation reliability per kilowatt of peak load reduction.

In AESC 2021, we find a default average VoLL value of $73 per kWh. This value is almost three times as large as the value derived in AESC 2018 ($26 per kWh in 2021 dollars). The change in the VoLL component is a result of updated information on VoLLs. This VoLL is then applied to the calculation of reliability benefits resulting from dynamics in New England’s FCM to estimate cleared and uncleared benefits linked to improving generation reliability. In AESC 2021, we find 15-year levelized values of

$0.47 per kW-year for cleared benefits and $8.45 per kW-year for uncleared benefits. These are 32 percent lower and 21 percent higher, respectively, than the same values estimated in AESC 2018, after adjusting for inflation. For cleared reliability, despite a higher VoLL, overall benefits are lower as a result of flatter supply curve assumptions for the capacity market. Changes to the capacity market have less of an impact on uncleared resources, which exist outside the capacity market. As a result, an increase in the VoLL produces an increase in the uncleared reliability value.

New in AESC 2021, we provide an example methodology to estimate benefits related to T&D reliability This estimate is based on data for National Grid Massachusetts. This value would likely differ for each jurisdiction. As a result, the methodology provided can be interpreted as guidance for calculating avoided costs.

Sensitivities

The following sections detail the inputs and results of the sensitivity analysis. In AESC 2021, we evaluate avoided costs under three different sensitivities. These sensitivities include:

- A natural gas price sensitivity with higher gas prices than were used in Counterfactual #1 ("High Gas Price Sensitivity")
- A climate policy sensitivity, where avoided costs for energy efficiency are calculated under a hypothetical regional climate policy with increased levels of electrification and clean energy ("No New EE Climate Policy Sensitivity")
- A climate policy sensitivity which models energy efficiency along with increased levels of electrification and clean energy ("All-In Climate Policy Sensitivity")

For each of these sensitivity cases, we find the following:

- In the High Gas Price Sensitivity, energy prices are 27 percent higher, capacity prices are 2 percent lower, RPS compliance costs are 8 percent lower, and non-embedded GHG costs are 21 percent lower. All prices are compared to Counterfactual #1.[4]
- In the No New EE Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 52 percent higher, and RPS compliance costs are 12 percent higher. All prices are compared to Counterfactual #3. This sensitivity features a new avoided cost (the incremental regional clean energy policy compliance cost, or IRCEP), which captures the incremental cost of the region reaching 90 percent non-fossil generation by 2035. This category increases total levelized avoided costs by 0.9 percent
- In the All-In Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 42 percent higher, and RPS compliance costs are 11 percent higher. All prices are

[4] All of the summary costs described here are framed in terms of 15-year levelized costs for summer on-peak for the WCMA region.

compared to Counterfactual #2. The new IRCEP cost category increases total avoided costs by 0.4 percent, all else being equal.

In the High Gas Price Sensitivity, energy prices are higher due to higher gas prices, which is the fuel that powers the marginal resource in most hours. The non-embedded GHG cost is lower because one of the inputs to this value is the energy price (in situations like this one, where the non-embedded GHG cost is based on the New England-derived marginal abatement cost). Generally speaking, higher energy prices will produce lower non-embedded GHG costs.

In the climate policy sensitivities, we find that energy prices typically only have minor changes relative to the comparative counterfactual. Capacity prices tend to be much higher, and are largely caused by high capacity prices in the early- to mid-2030s. In these years, the system switches to winter peaking and demand increases quickly. Costs of RPS compliance are also higher due to increased demand for electricity. Finally, we find that the additional cost of compliance associated with the region reaching 90 percent non-fossil generation by 2035 is low, on a levelized basis. This is due to several factors, including the fact that many states in New England are already reaching very high non-fossil percentages by 2035, and because the cost of compliance is zero in the near term (as the policy does not come into effect until the mid-2020s).

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 wholesale natural gas price is the market price of gas that is sold to local distribution companies (LDC), electricity generators, and other large end-users at interstate pipeline delivery points. The discussion then addresses factors impacting the price basis for natural gas sold in New England and ends with a discussion of the methodology used to quantify avoided costs of natural gas. 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.

Natural gas prices in AESC 2021 are significantly lower than in AESC 2018. Lower price forecasts have been a persistent trend over the past decade as a result of assumptions in the AEO Reference cases that were too conservative in terms of shale gas reserves, productivity, drilling costs, and production growth.

2.1. Introduction

The dampening effect of the COVID-19 pandemic on end-use consumer demand for natural gas and other fuels resulted in 2020 experiencing the lowest Henry Hub prices in over two decades. Producers reacted to this reduction in demand by shutting-in production and reducing drilling. However, low gas prices caused natural gas-fired generation to take market share from coal-fired electric generation and made liquified natural gas (LNG) exports from the United States highly attractive. As a result, total demand for natural gas in 2020 was nearly identical to 2019. As the supply-demand balance began to tighten in the fall of 2020, Henry Hub prices began to escalate, providing producers an incentive to increase drilling and production, but dampening the economics of gas-fired electric generation. Against this backdrop, the latest Annual Energy Outlook (AEO), published by the EIA in early February 2021, projects a slow return to "normal," indicating long-lasting effects on the energy sector from the COVID-19 pandemic. AEO projects that it will take until 2023 for natural gas production to return to its pre-pandemic peak, and that it will take until 2026 for domestic consumption to reach a new peak. Over the longer term, the projections for gas prices in AEO 2021 are not substantially different than prices projected in AEO 2020.

Responses to the pandemic in the physical natural gas market were not mimicked by the financial market or trading activity during 2020. This meant that trading was not substantially different from the prior year's record high activity.[5] AEO 2021 projects that prices will begin a sustained rebound in 2025 as

[5] While Federal Energy Regulatory Commission (FERC) Form 552 filings reported record volumes in 2019, Chicago Mercantile Exchange (CME) and Intercontinental Exchange (ICE) reported slightly lower trading volumes. Natural gas is also traded on other platforms, such as NASDAQ.

producers pursue less-economic reserves. Prices and financial trading volumes continue to indicate a very active market, anchored by NYMEX Henry Hub futures.[6] Although prices and outlooks fluctuate, there remains an active wholesale natural gas market in New England for gas that is sold to LDCs, electricity generators, and other large end-users at interstate pipeline delivery points. Note that recent energy market disruptions and macroeconomic impacts due to the COVID-19 pandemic widen the uncertainty band of any price forecast.[7]

2.2. Gas prices and commodity costs

The following sections provide an overview of historical natural gas prices and projected future wholesale natural gas prices.

Background

The U.S. fuel extraction industry appeared past its prime at the start of the 21st century, but early in the 2010s, shale gas and oil suddenly became an industry with significant growth potential. Order-of-magnitude drilling economics improvements have changed the market's perception of both natural gas and crude oil from increasing-cost commodities to flat-to-declining-cost commodities. Capital became widely available to small- and medium-sized companies willing to expand drilling in new shale and tight-sand formations, to build new processing and transport infrastructure, and to consume growing gas volumes in domestic sectors or export the surplus to growing overseas LNG markets. Indeed, in 2000 the United States consumed about 64 billion cubic feet per day (Bcfd) of natural gas, of which 10 Bcf per day was imported, while in 2020 consumption was about 83 Bcfd and over 7 Bcfd was exported.[8]

In the three years since the AESC 2018 analysis, these trends have been extended through significant production growth, mainly in Texas and Appalachia. This time period has also seen increasing domestic consumption, mainly through electric generation, and surging exports of LNG which are primarily from new terminals on the Gulf Coast and Eastern Seaboard. However, the upstream (production) side has seen a geographical shift. Natural gas in Appalachia had been in surplus for several years because of lags

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[6] NYMEX Henry Hub futures prices are traded for 120 months out. There are also futures prices and price differentials (basis) for other regional natural gas hubs traded on the NYMEX or other organized exchanges. Cornerstone Research: *Characteristics of U.S. Natural Gas Transaction* (Jul 2020) reported that trading volumes during the first of this year indicate and increase in 2020; p. 10.

[7] Prices quoted on the NYMEX and other active futures exchanges represent a collective market view of supply and demand conditions in the future. However, there is a risk when using any price forecast in business decisions. Physical players such as LDCs and producers purchase or sell futures to hedge price risk. A futures contract provides insurance against price volatility. Buying and selling entities including traders know they run the risk that they will incur an opportunity cost—buying or selling at too low or too high a price. To many, this is an acceptable risk, giving up potential profits for a known price. Others may prefer purchasing derivative financial instruments that can be used to cover some of the opportunity cost risks; for example, protective collars can be purchased that provide additional downside or upside price protection, and the risk of purchasing too much or too little gas due to adverse weather can be hedged via weather derivatives.

[8] U.S. EIA, *Natural Gas Annual*, available at https://www.eia.gov/naturalgas/annual/. The 2019 edition was released on September 30, 2020. Historical data is published in the EIA's *Monthly Energy Review*.

in pipeline infrastructure, resulting in falling prices in the region. Simultaneously, high oil prices created a boom in shale oil plays, mainly in the Permian Basin. Surging oil production also resulted in a large increase in associated gas production.[9] Since the beginning of 2018, Permian gas production has more than doubled, compared to a 30 percent increase in Appalachian volumes. However, drilling activity dropped sharply in the second and third quarters of 2020 resulting in a decline in associated gas production and a flattening of Appalachian output.

All the primary gas markets were affected by these production shifts, by new infrastructure, and by new gas-fired electric generation. In New England, for example, gas-fired power now accounts for about half of the installed generating capacity in the six-state region, which is three times what it was 20 years ago. Volumes also increased at most gas trading hubs and the ability to arbitrage regional price differentials rose with additional pipeline capacity and new commodity trading platforms. Although a few small, incremental pipeline projects were added over the past few years, New England avoided large-scale investments in natural gas infrastructure; nonetheless, the region still exhibited a downward gas price trend over the past decade.

Over the past two years, the New England gas market has seen a small increase (see Section 2.3. *New England natural gas market*). However, the primary sources of gas supply to New England and the delivery pipelines are unchanged. As in prior AESC studies, we conclude that there are three main components to New England gas costs.

1. The natural gas price at the point of purchase at a market trading hub or at the production site (the “supply area” price or “commodity cost”);
2. The pipeline transportation cost from the trading hub or 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.

Supply area natural gas prices

Natural gas consumed in New England is sourced from various points in the United States and Canada. These sources vary depending on the purchasing entity and contractual arrangements, as well as seasonal differences such as storage and LNG. Gas is purchased at hubs in New England, such as the Algonquin (AGT) Hub, or hubs further south, in Canada, or in other locations. As in the rest of North America, because of the integrated pipeline network, gas prices in New England are strongly correlated to the Henry Hub benchmark. Therefore, similar to previous AESC studies, Henry Hub serves as the foundation for developing price projections relevant to New England markets. The rationale for this choice is that Henry Hub has been the U.S. gas price benchmark since the early 1990s and is likely to continue that role in the foreseeable future. There are many reasons for choosing Henry Hub.

[9] Associated natural gas or associated-dissolved natural gas is natural gas that occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved gas).

1. Foremost, perhaps, is that it 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.[10] The New York Mercantile Exchange (NYMEX) trades Henry Hub monthly gas with contracts extending for 120 months.

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

3. For many of the other trading points (hubs) throughout the United States, 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. EIA (in the AEO) and many other organizations base their price forecasts on Henry Hub.

5. The burgeoning surplus of gas in Appalachia and other regions is being increasingly funneled to LNG export terminals along the Gulf Coast (Texas and Louisiana). From the end of 2017 through 2020, export capacity has increased from roughly 3 Bcfd to 10 Bcfd. Nearly 10 percent of U.S. gas demand now comes from LNG exports, with the bulk of that along the Gulf Coast. Pipelines have correspondingly increased capacity to meet this demand. Even more LNG export capacity is in the planning stage. The AEO and most other forecasts envision that LNG exports will be the marginal market for natural gas at least over the next decade and that the Henry Hub pricing point in Louisiana will be a primary signal in this new market dynamic.

Although natural gas prices quoted by the NYMEX are volatile, they represent the current collective wisdom of the gas market. Prices change daily as physical buyers and sellers and financial players continually assess new data and reformulate expectations about the future gas market. Near-term factors such as storage balances, weather, and demand and supply expectations have a larger influence in the front of the price curve. These prices influence decisions by producers, consumers, and investors that can affect the future demand and supply balance. Most NYMEX participants are "hedgers" who use the futures market to reduce the risk of financial losses from price changes, i.e., lock-in a price to buy or sell gas. With more hedging in the winter months when gas demand peaks, there is marked seasonality in natural gas trading. Most hedging is short-term, i.e., over the next 12 to 18 months, so there is more liquidity (larger volume of transactions) in the near months of the natural gas market). Liquidity falls significantly beyond 18 months. Thus, similar to previous AESC studies, the short-term natural gas price forecast relies entirely on NYMEX Henry Hub futures. In addition, we use the seasonality in monthly prices observed in the 2022–2023 NYMEX futures complex to develop long-term monthly trends for the Henry Hub gas price over the 2021–2035 study period.

[10] Details on the NYMEX Henry Hub Contract can be found on the CME website: http://www.cmegroup.com/trading/energy/nymex-natural-gas-futures.html. There is seasonality in the 12-year NYMEX Henry Hub futures complex and we are using that seasonality to convert the annual AEO forecasts to monthly forecasts. CME data was downloaded for use in the AESC 2021 Study on February 1, 2021.

As with previous AESC studies, we rely on AEO for longer-term Henry Hub price forecasts. The most recent current AEO was published in February 2021 (AEO 2021).[11] There are numerous reasons for choosing AEO for longer-term price forecasts; foremost is the extensive documentation and transparency of the inputs and models used by EIA. There are many companies, consultants, and other organizations that forecast natural gas and other prices. However, there is no way to evaluate them without complete datasets, assumptions, or documentation on model algorithms.[12] The EIA forecasts are public, transparent, and incorporate the long-term feedback mechanisms of energy prices upon supply, demand, and competition among various fuels. Previous AESC studies have relied on the AEO Reference Case, which generally assumes current legislation and environmental regulations. Specifically, AEO 2021 assumes government actions for which implementing regulations were available as of the end of September 2020 and macroeconomic assumptions based on third and fourth quarter 2020 assessments.[13] These macroeconomic assumptions include the effects of the COVID-19 pandemic on natural gas and other energy sectors.

EIA has recognized an increased level of uncertainty in its projections due to the impacts of the COVID-19 pandemic on energy markets and the wider economy.[14] The COVID-19 pandemic represents a novel forecasting challenge. As in previous outlooks, the Reference case for AEO 2021 is a projection rooted in experience to date and the current short- and medium-term economic outlook. But the influence of the pandemic in this forecast and the necessity of conjecturing what the recovery will look like means that the longer-term view may be particularly uncertain.

The Reference case in AEO 2021 anticipates that economywide demand for energy in the United States will not return to 2019 levels until 2029.[15] On average, the Henry Hub price forecast for the AEO 2021 reference case is approximately 2.6 percent lower than the corresponding forecast from AEO 2020. Meanwhile, alternative scenarios explored in AEO 2021 (“side cases”) consider the impacts of differing economic growth rates resulting in a return to pre-pandemic economic activity and energy consumption levels in shorter or longer order.

For AESC 2021, we use the current NYMEX Henry Hub futures forecast for short-term prices (through 2023) and AEO 2021 for medium- and long-term prices.[16] We believe that the current NYMEX Henry Hub

[11] U.S. EIA. 2021. Annual Energy Outlook (AEO) 2021. https://www.eia.gov/outlooks/aeo/.

[12] AESC 2021 differs from its predecessors in that the timing of this year’s study allows for the use of the most recent AEO projection. Previous AESC studies, by virtue of their study timeline, frequently used AEO projections that were a year or more out-of-date at the time of AESC’s publication.

[13] Assumptions are documented in several reports. See EIA’s AEO assumptions at https://www.eia.gov/outlooks/aeo/assumptions/.

[14] U.S. EIA, 2021. AEO 2021 narrative, p 4, at https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf.

[15] Ibid.

[16] The gas price forecast methodology employed in AESC 2021 differs from that of AESC 2018 only in that we do not transition from the NYMEX futures value, used for the preliminary forecast years, to the AEO forecast series for the later forecast years

price forecast incorporates an independent and collective view of the market supply and demand balances over the next three years. It also incorporates current expectations on the effects and duration of the COVID-19 pandemic. Meanwhile, AEO 2021 represents a neutral, third-party projection of Henry Hub prices based on recent trends and expectations, accounting for the COVID-19 pandemic, but ultimately reflecting conventional trends outlasting the impacts of the pandemic.[17] Factors influencing the longer-term forecasts of energy demand beyond the period of uncertainty associated with the COVID-19 pandemic include economic and population growth; increasing reliance on renewables and consumption of natural gas and electricity; and technological, behavioral, and policy shifts.

The following section provides highlights of the AEO 2021 Reference case and other AEO cases.

AEO 2021 Reference case

Compared to the recent past, the AEO 2021 Reference case projects the U.S. natural gas industry growing more slowly in the decades ahead. Gas production in the United States (dry gas) increased by 57 percent from 2010 to 2019 while AEO 2021 has production growing by only 23 percent from 2024–2050.[18] Similarly, consumption slows markedly in all sectors. The decline is most pronounced in the residential sector, which sees flat-to-declining gas use in the future.

In AEO 2021, real Henry Hub prices (in 2021 dollars) are projected to fall from $3.23 per MMBtu in 2021 to $2.78 per MMBtu in 2023. Prices then increase by 2.4 percent per year, reaching a price of $3.68 per MMBtu in 2035. Producers require higher prices to expand into less prolific and more expensive-to-produce areas to meet the growth in gas demand and LNG exports.

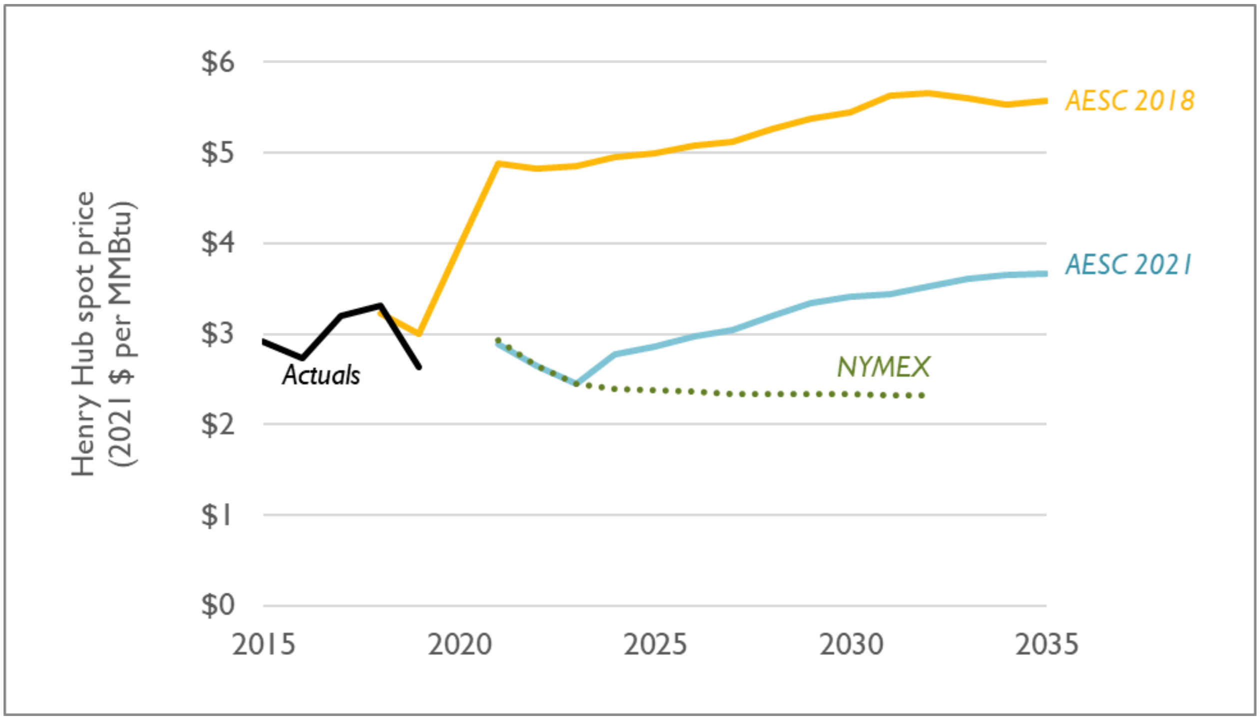
Figure 1 shows the forecast of Henry Hub prices used in AESC 2021. As described above, these rely on current NYMEX futures (dated February 1, 2021) for prices between 2021 and 2023. Prices in 2024 through 2035 are based on AEO 2021. Figure 1 also compares the Henry Hub price used in AESC 2021 with the price forecast used in AESC 2018 (in 2021 dollars).

with a bridge year calculated by averaging the two series. Instead, we transition directly from NYMEX futures (for 2021-2023) to the AEO forecast series (for 2024 and beyond).

[17] Ibid.

[18] “Dry” gas is consumer-grade natural gas. Basically, it is natural gas that that has been processed to remove hydrocarbon liquids and other impurities so that it has uniform properties that make it transportable and useable by all consumers. Dry natural gas production equals marketed production less extraction loss.

Figure 1. Henry Hub price forecasts (Actuals, NYMEX, AESC 2020, and AESC 2018)



As shown in Figure 1, Henry Hub natural gas prices average 34 percent lower in AESC 2021 compared to AESC 2018 over the 2021–2035 period. In general, forecasts of Henry Hub prices have continually declined over the past decade for several reasons.

1. Productivity in shale drilling has been increasing steadily. Average productivity (new well gas production per rig) as reported by EIA was about 1,284 Mcf at the beginning of 2014. Productivity was 3,570 Mcf in EIA's January 2018 report and 6,906 Mcf in the latest (2021) report.[19] This trend implies decreasing costs per unit of production, although AEO continues to assume that new supply will not be as productive as in the past, thus requiring higher prices to induce drilling.

2. A growing portion of gas production has been coming from oil wells (e.g., "associated natural gas"). For oil producers, drilling decisions are based on crude oil prices and any natural gas sold is considered a byproduct. Depending on gas pipeline availability and flaring regulations, this gas will be produced at any price as long as crude oil economics are positive. As new tranches of associated gas are marketed, they often displace existing gas production pressuring gas prices.

3. Realtime indicators are difficult to ignore. Since 2010, average gas prices have been on a downward trend—weekly, monthly, and annually. For example, the average Henry Hub spot price for two years prior to the initial 2015 AESC forecast was about $4.59 per MMBtu (in 2021 dollars), while for the 2018 report it was $2.96 per MMBtu. For the two years prior to AESC 2021 (2019 and 2020), the average price was $2.33 per MMBtu. The

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[19] U.S. EIA. 2021. "Drilling and Productivity Report," January 19.

past decade has seen price spikes due to abnormal weather or short-term storage deficits, but projecting a sustained upward price surge is difficult to justify.

4. The COVID-19 pandemic initially exacerbated a bearish price cycle. The average Henry Hub spot price for the 12-months ending October 2020 was $2.00 per MMBtu, the lowest in over two decades. This price signal has led to near-record short-term production declines the second and third quarters of 2020. The market has recognized this, with NYMEX Henry Hub futures averaging closer to $3.00 per MMBtu beginning in the fourth quarter.

Natural gas prices at other upstream supply points

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's natural gas prices?

Without indigenous production, New England continues to acquire gas from outside the region via:

1. Six pipeline systems including Tennessee Gas Pipeline (TGP) and Algonquin Gas Transmission (AGT) from the south; Iroquois Gas Transmission (IGTS) from the west through New York State; and Maritimes & Northeast Pipeline (MNP) along with Portland Natural Gas Transmission (PNGTS) from Canada via TransCanada Pipeline (TCPL). See below for a more detailed description of the six pipeline systems.

2. Two LNG import terminals in the Boston area including Excelerate Energy's Northeast Gateway Deepwater Port and Exelon Generation's Everett terminal. There is also the Canaport LNG import terminal in New Brunswick, from which regasified LNG can be piped down MNP into New England.

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 Marcellus/Utica has outstripped natural gas consumption in the Northeast. As a result, the physical source of New England pipeline gas is being increasingly supplied from this nearby basin even if shippers are notionally purchasing gas from distant supply basins (Gulf Coast, Western Canada, Permian Basin, etc.).[20] Thus the price at hubs that source Marcellus/Utica gas is increasingly relevant to New England.

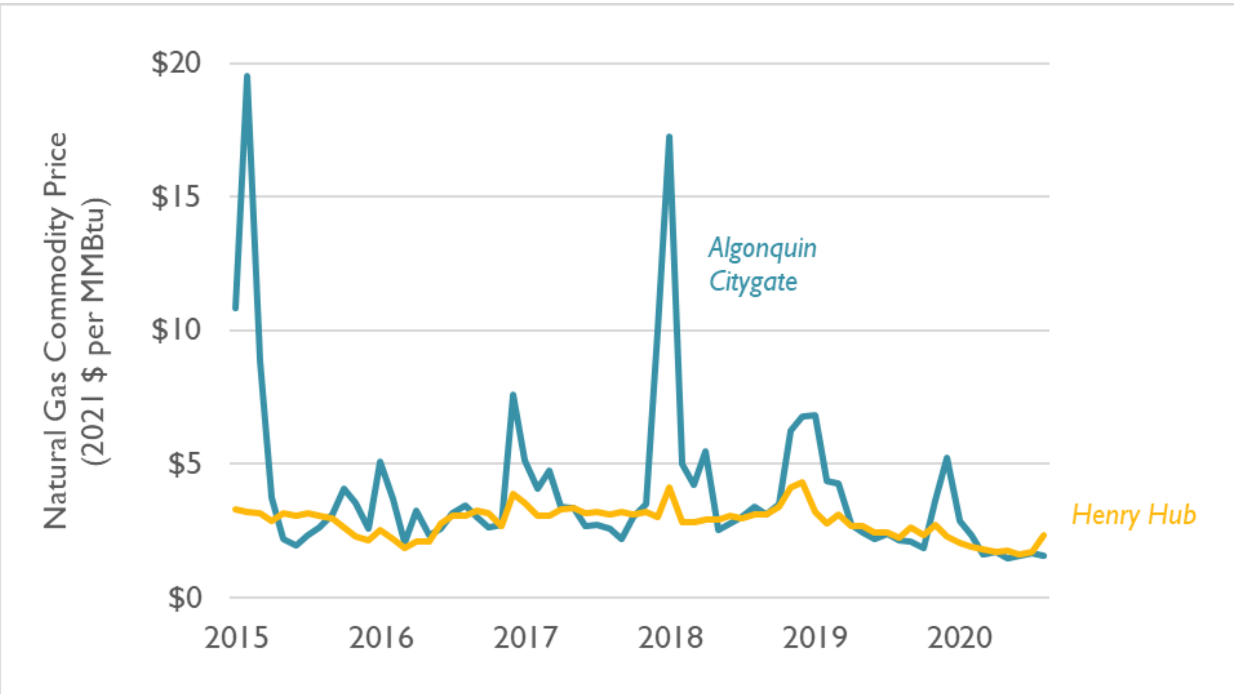
Although sourced from various upstream supply basins, a significant volume of New England gas is priced at the Algonquin Citygate Hub. AGT basis futures are traded on the Intercontinental Exchange

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

(ICE) and there is a market up to 48 months out.[21] AGT spot prices are also quoted in several publications[22] and on the EIA website.[23] For 2024 and later years, to calculate the future monthly variation in prices for Henry Hub, Algonquin Citygate, and other and hubs upstream of New England, we average two years of projected monthly data (based on NYMEX) for the period 2022–2023.[24] For Henry Hub, the "shape" of this monthly variation is applied to the annual data from AEO 2021. For Algonquin Citygate and other hubs, we simply add the average monthly basis to the Henry Hub value.

We have also analyzed historical monthly basis data for these pricing points, allowing us to apply the seasonality in monthly prices to our longer-term projections. See Figure 2 for a historical comparison of gas prices at Algonquin Citygate and Henry Hub.

Figure 2. Historical comparison of natural gas prices at Algonquin Citygate Hub and Henry Hub



[21] Intercontinental Exchange (ICE). Last accessed March 9, 2021. "Algonquin Citygates Basis Future." *theICE.com*. Available at https://www.theice.com/products/6590124/Algonquin-Citygates-Basis-Future.

[22] Natural Gas Intelligence (NGI). Last accessed March 9, 2021. "Algonquin Citygate Daily Natural Gas Price Snapshot." *NaturalGasIntel.com*. Available at https://www.naturalgasintel.com/data-snapshot/daily-gpi/.

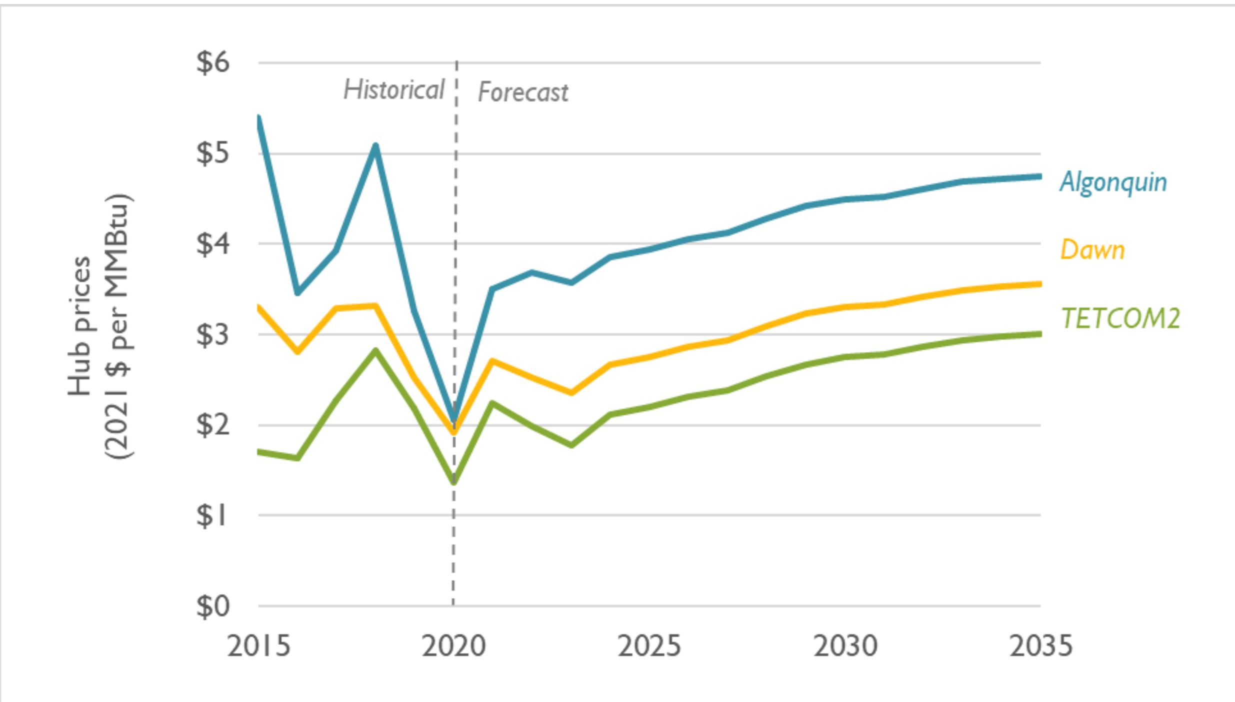
[23] U.S. EIA. Last accessed March 9, 2021. "Daily Prices." *Today in Energy*. Available at https://www.eia.gov/todayinenergy/prices.php.

[24] The term upstream generally refers to hubs and other points closer to the source of gas production.

In AESC 2021, we use the Texas Eastern Zone M-2 (TETCO M2) price, which is more representative of the actual prices paid by New England LDCs.[25] To cover the major gas supply sources, we model monthly prices at the Dawn Ontario Hub and TETCO M2 Hub using a similar methodology as our projection for the Algonquin Citygate basis (see Figure 3). The projected monthly basis values for these hubs are assumed to remain constant in real dollar terms over the modeling period.

While often correlated, natural gas prices at each hub will vary, depending on supply, demand and pipeline capacity, transport costs, and other conditions. There are trading platforms for these hubs: NYMEX trades (TETCO M2), and Natural Gas Intelligence (NGI) publishes prices for the Dawn Hub.[26] In most cases there is both a spot and a futures market of varying lengths at these hubs. Also note that these price forecasts implicitly assume no new large-scale pipeline expansion projects, other than ones under construction slated over the next year.[27] We believe the futures prices used in this analysis embed an unbiased estimate of the market's expected seasonal demand-supply pressures in the near term.

Figure 3. Historical and projected prices for AGT Hub, Dawn Hub, and TETCO M2 Hub



[25] In AESC 2018, we used the Dominion South Point (hub) index to measure gas prices in the Marcellus shale producing areas in and about Pennsylvania.

[26] NGI. Last accessed March 9, 2021. "Dawn Forward Fixed Natural Gas Price Snapshot." *NaturalGasIntel.com*. Available at http://www.naturalgasintel.com/data/data_products/forward-contracts?location_id=MCWDAWN&region_id=midwest.

[27] See Algonquin's "Atlantic Bridge Project" CP16-9.

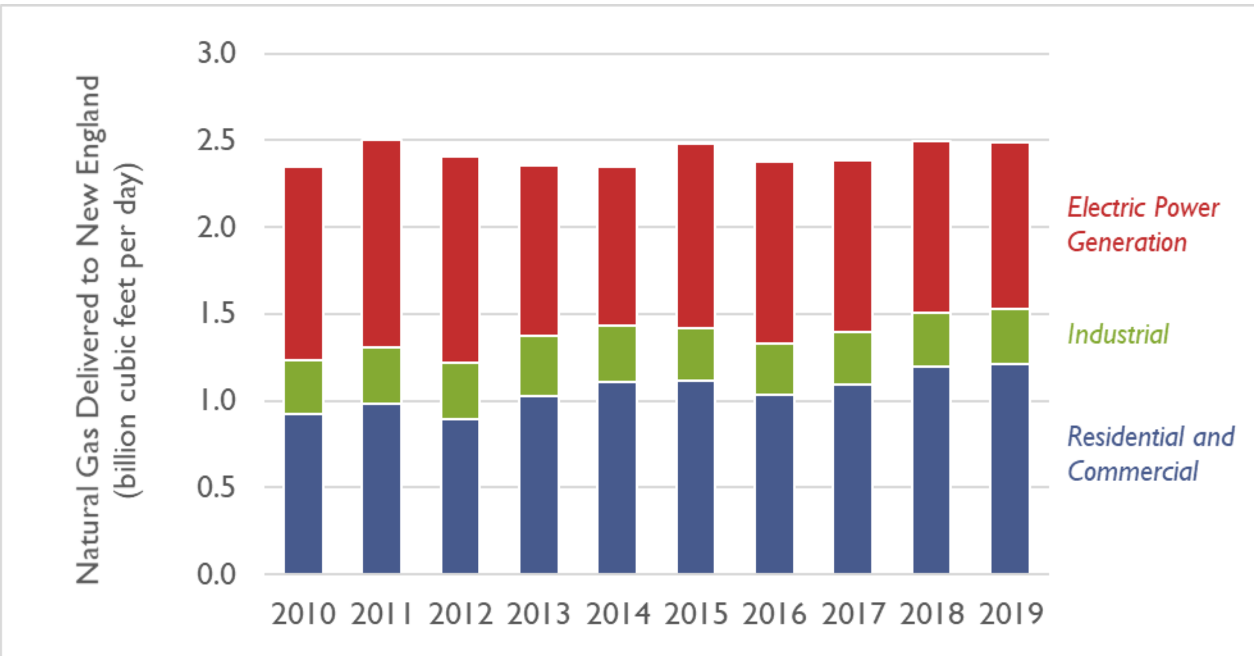
2.3. New England natural gas market

In addition to the commodity costs discussed above, natural gas avoided costs include the costs of transmission, storage, and peaking resources needed to make gas available where and when it is consumed. This section addresses the gas supply resource costs that would be avoided by reducing gas use and describes our methodology for calculating the avoided natural gas costs by end-use.

Natural gas consumption

Figure 4 shows the natural gas delivered to end-users in the six New England states for the years 2010 through 2019. Growth in residential and commercial consumption has been largely offset by lower gas use for electricity generation.

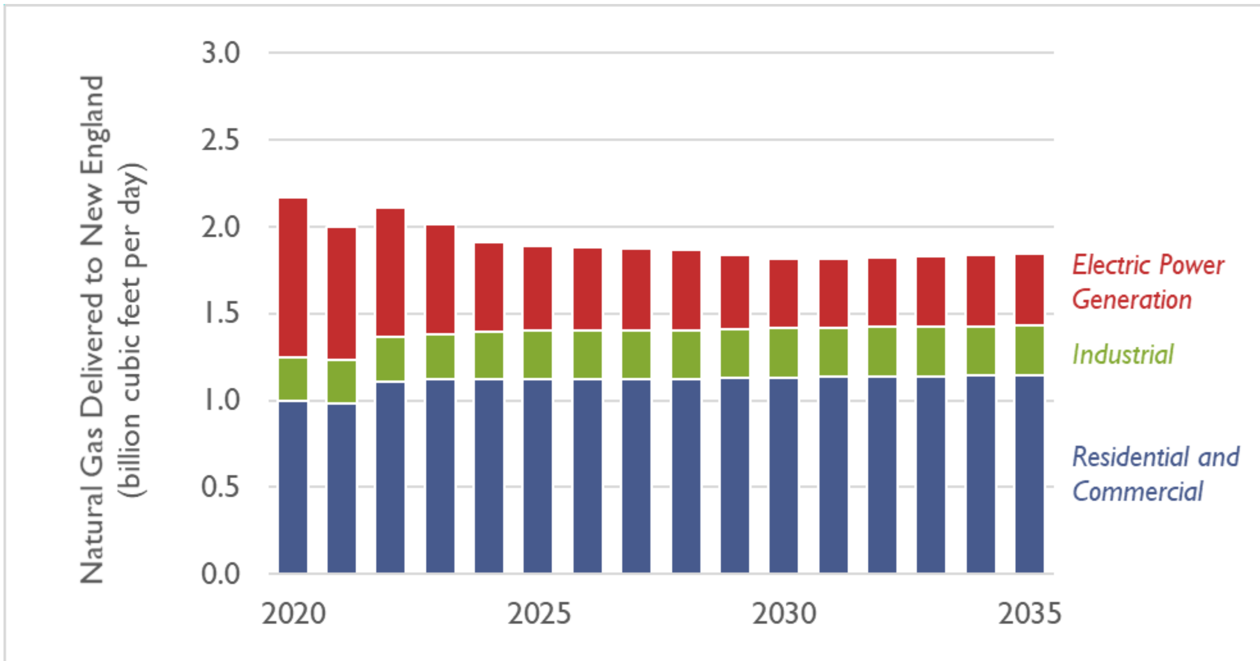
Figure 4. Historical natural gas deliveries in New England



Source: Energy Information Administration (EIA). Available at https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm.

Going forward, the AEO 2021 Reference case forecast for New England shows a small near-term increase in consumption in the residential, commercial, and industrial sectors, then a flattening of gas consumption from the mid-2020s through the mid-2030s (see Figure 5). Meanwhile, EIA projects gas consumption in the electric power sector to be halved by 2025, then remain at a relatively consistent level through the mid-2030s.

Figure 5. AEO 2021 natural gas consumption forecast for New England



Source: Energy Information Administration (EIA). Available at https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_2.1.xlsx.

Recent New England LDC forecasts show annual growth in customer requirements ranging from 0.2 percent to 2.3 percent per year (see Table 1). For the 13 LDC forecasts shown, the weighted average increase in requirements over a five-year period is just under 2 percent per year.[28]

There are several reasons why the LDC forecasts would be different from the EIA forecast:

- The LDC forecasts are "planning load" forecasts, not forecasts of total consumption. Planning load customers are sales customers that buy gas from the LDC, and transportation-only customers that buy gas from marketers that receive upstream capacity resources from the LDC under retail choice programs. "Capacity exempt" transportation customers that do not use LDC supply resources are excluded.
- LDC planning load excludes most gas used for electricity generation. Gas-fired power plants in New England typically receive gas supplies directly from an interstate pipeline or transport gas on an LDC under a special contract that makes them capacity-exempt.
- Some LDCs adjust their forecasts to include potential migration of existing capacity-exempt transportation customers to sales service or capacity-assigned transportation service. Shifting gas use by existing capacity-exempt transportation customers into

[28] Growth rates weighted by the annual planning load forecasts for 2020-21.

planning load causes the planning load growth rate to be higher than the actual growth in total consumption.

- Recent LDC forecasts reflect lower 2020 and 2021 gas use caused by COVID-19; they assume that consumption will bounce back later in the forecast period. This would cause the average annual growth rates for forecasts with a 2020 start date to be somewhat higher than pre-COVID forecasts, all else being equal.

- Finally, there are questions about the extent to which the econometric forecasts produced by New England LDCs reflect the future impacts of state initiatives to reduce GHG emissions. The Massachusetts Attorney General has suggested that LDCs should be required to submit forecasts for periods longer than five years in order to address the expected transition away from natural gas as a heating fuel.[29]

Table 1. New England LDC natural gas requirements forecasts

Utility	CAGR (%)	2020-2021 forecast (MMcf)		Forecast period	Case or Docket Number
		Annual	*Design Day*		
National Grid (MA)	2.3	136,633	1,425	2020 to 2025	MA DPU 20-132
Eversource Gas	0.8	48,660	522	2019 to 2024	MA DPU 19-135
NSTAR Gas	1.5	47,907	537	2019 to 2024	MA DPU 20-76
Liberty (MA)	1.0	6,452	77	2020 to 2025	MA DPU20-92
Berkshire Gas	0.5	6,472	66	2020 to 2025	MA DPU 20-139
Fitchburg Gas	0.2	2,314	23	2020 to 2025	MA DPU 21-10
CT Natural Gas	1.6	36,124	355	2020 to 2025	CT PURA 1820-10-02
Southern CT	1.2	33,167	325	2020 to 2025	CT PURA 1820-10-02
Yankee Gas	2.2	56,256	487	2020 to 2025	CT PURA 1820-10-02
National Grid (RI)	1.8	36,152	389	2019 to 2025	RI PUC 5043
EnergyNorth	2.3	15,650	165	2017 to 2022	NH PUC DG 17-152
Northern Utilities	1.5	15,628	143	2019 to 2024	NH PUC DG 19-126
Vermont Gas	0.2	7,162	72	2020 to 2025	VT PUC 20-1520
Total		**448,557**	**4,585**		

Gas supply resources

The natural gas consumed in New England comes from the natural gas pipelines that transport gas from producing areas in the United States and Canada, and import terminals in Massachusetts and New Brunswick that receive LNG by ship. A small, but growing amount of natural gas is transported into New England by truck as either LNG or compressed natural gas (CNG).

Gas transmission pipelines

Six major natural gas pipeline systems deliver gas to New England markets (see Figure 6).

Tennessee Gas Pipeline (TGP): Two branches of the TGP mainline deliver gas into New England. The "200 Line" enters Massachusetts from upstate New York and extends into the Boston area. The "300

[29] Massachusetts Office of the Attorney General's June 4, 2020 petition in Docket D.P.U. 20-80, pp. 12-13.

Line" enters southwestern Connecticut and connects to the 200 Line at Agawam, MA. Lateral pipelines transport gas into Rhode Island and New Hampshire.

Algonquin Gas Transmission (AGT): AGT is a regional pipeline that extends from central New Jersey to Boston. AGT receives gas from TGP at Mahwah, NJ and from Millennium Pipeline at Ramapo, NY. AGT delivers gas in Connecticut, Rhode Island, and Massachusetts. The AGT system also includes a 25-mile undersea pipeline (the "HubLine") that extends from Weymouth, MA to an interconnection with Maritimes & Northeast Pipeline (MNP) in Salem, MA.

Iroquois Gas Transmission System (IGTS): IGTS 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 connects with TGP at Wright, NY, and with AGT at Brookfield, CT. Direct deliveries from IGTS into the New England are constrained by the capacity of Connecticut LDCs and power generators to receive gas at IGTS meters and competition from downstream markets in New York.

Portland Natural Gas Transmission System (PNGTS): PNGTS receives natural gas from TCPL at the New Hampshire-Quebec border. TCPL delivers this gas using capacity that it holds on TransCanada's (Trans Quebec and Maritimes) TQM pipeline. PNGTS connects with MNP at Westbrook, ME and delivers gas into TGP at Dracut, MA.

Maritimes & Northeast Pipeline (MNP): MNP was originally built to transport gas from offshore Nova Scotia to Canadian and U.S. markets.[30] The U.S. portion of the MNP system extends from the Maine-New Brunswick border to northeastern Massachusetts. MNP also receives gas from the Brunswick Pipeline, which is the outlet for the Canaport LNG terminal at St. John in New Brunswick. MNP connects with PNGTS at Westbrook, ME, with TGP at Dracut, MA, and with AGT at Salem, MA.

TransCanada PipeLines (TCPL): The TCPL mainline extends from Alberta to Quebec. TCPL receives gas in Alberta and from Enbridge Gas at the Parkway interconnect in southwestern Ontario.[31] TCPL connects directly to Vermont Gas System (VGS), and delivers gas into IGTS and PNGTS.

Liquefied natural gas (LNG) import terminals

Imported LNG is received at three terminals located in Massachusetts and New Brunswick.

Distrigas of Massachusetts: The Distrigas LNG terminal, located in Everett, MA, delivers gas to TGP, AGT, National Grid, and the Mystic Generating plant. Distrigas also delivers LNG into trucks that supply peaking gas facilities throughout the region.[32]

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[30] Natural gas production in Nova Scotia ended in 2018.

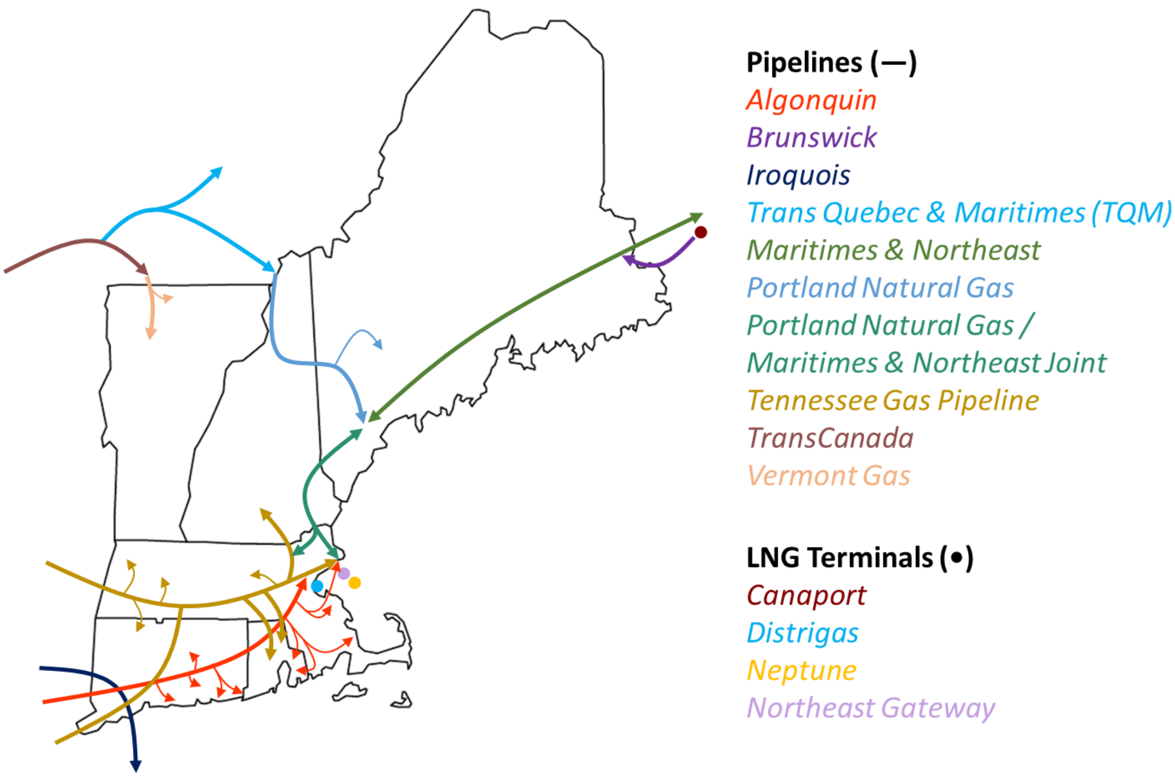
[31] Enbridge Gas (formerly Union Gas Limited) operates the Dawn Hub.

[32] The Distrigas terminal is owned by an Exelon Corporation subsidiary.

Northeast Gateway: Northeast Gateway is an offshore LNG receiving facility that connects to the AGT HubLine. Northeast Gateway began operating in 2008, but it has received only a few winter-season shipments in recent years.[33]

Canaport LNG: The Canaport LNG terminal has close to 10 Bcf of storage capacity and can send out approximately 1Bcfd. Repsol Energy North America, the Canaport operator, has a long-term contract for firm transportation service on MNP and uses this capacity to deliver gas at Dracut and Salem, and to markets in Maine.

Figure 6. Natural gas pipeline infrastructure in New England and nearby regions



Source: Synapse Energy Economics, 2021.

Natural gas delivery capacity

Total gas delivery capacity into New England increased by roughly 4 percent from 2018 to 2021 and is expected grow by another 1.5 percent from 2021 to 2024 (see Table 2). For AGT and TGP, we show the estimated west-to-east capacity to deliver gas into New England from New York. The IGTS capacity is an estimate of the amount of gas that can be received in Connecticut, and it excludes capacity used to transport gas through New England to downstream markets in New York. The “TCPL Direct” quantities are the receipt capacities of VGS and PNGTS at the U.S.-Canada border. The “LNG Dependent” quantities

[33] A second offshore LNG receiving terminal, Neptune, was built about the same time, but is now inactive.

show the certificated end-to-end capacity of the MNP pipeline and the estimated sendout capacity of the Distrigas facility, based on the take-away capacity of the interconnected pipelines. Note that the effective delivery capacity for MNP and Distrigas at any point in time is likely to be lower than shown in the table, since it will depend on the availability of LNG supply.

The supply of natural gas to the New England market is also reduced by exports to New Brunswick and Nova Scotia. EIA reports that 0.25 Bcfd of natural gas flowed into New Brunswick from Maine in 2019.[34] Canadian LDCs and end-users have contracted for pipeline capacity in the Atlantic Bridge, Portland XPress, and Westbrook XPress expansion projects.

Table 2. Historical and Projected Natural gas delivery capacity into New England (Bcfd)

	JAN 2018	JAN 2021	JAN 2024
AGT	1.82	1.91	1.91
TGP	1.39	1.39	1.42
IGTS	0.26	0.26	0.26
West-to-East	**3.47**	**3.56**	**3.59**
PNGTS	0.21	0.32	0.40
VGS	0.07	0.08	0.08
TCPL Direct	**0.28**	**0.40**	**0.48**
MNP	0.83	0.83	0.83
Distrigas	0.70	0.70	0.70
LNG Dependent	**1.53**	**1.53**	**1.53**
TOTAL	**5.28**	**5.49**	**5.60**

Table 3 provides details on recent and planned pipeline expansion projects that affect gas delivery capacity into the New England market.

34 U.S. EIA. Last accessed March 9, 2021. "U.S. Natural Gas Exports and Re-Exports by Point of Exit." *eia.gov.* Available at https://www.eia.gov/dnav/ng/ng_move_poe2_a_EPG0_ENP_Mmcf_a.htm.

Table 3. Recent and planned New England pipeline expansions

Pipeline	Project	Capacity (Bcfd)	Description	Status
AGT	AIM	0.342	Expand from Ramapo, NY to New England citygates	Completed early 2017
TGP	CT Expansion	0.072	Expand from Wright, NY to CT citygates	Completed in 2017
AGT	Atlantic Bridge	0.133	Expand from Ramapo, NY to Salem, MA	Added 0.040 Bcfd in 2017, 0.093 Bcfd in 2019
TGP	261 Upgrades	0.027	Upgrade compression and expand Agawam, MA lateral	Lateral completed 2020. Compression planned for 2021
PNGTS	Portland XPress	0.064	Expand from Canadian border to Dracut, MA	Completed 2018, 2019, and 2020
PNGTS	Westbrook XPress	0.123	Expand from Canadian border to Westbrook, MA and Dracut	Added 0.043 Bcfd in 2020. Phases II and III in 2021 and 2022.
Total	**-**	**0.761**	**-**	**-**

Peaking facilities

Most New England LDCs operate on-system peaking facilities that inject either vaporized LNG or propane into the distribution system during periods of high gas demand (see Table 4). The total design-day production capacity for these facilities is approximately 1.5 Bcfd. Many of the LDC peaking facilities have on-site storage, but others are satellite facilities that require mid-winter refill by truck.

Table 4. New England LDC peaking facilities

Gas Utility	Type	Number of facilities	Aggregate Delivery Capacity (Bcf/day)	Aggregate Storage Capacity (Bcf)
National Grid (MA)	LNG	7	0.508	4.934
Eversource Gas	LNG	4	0.112	1.688
NSTAR Gas	LNG	2	0.210	3.650
Liberty (MA)	LNG	1	0.018	0.165
Berkshire Gas	LNG	1	0.003	0.010
Fitchburg Gas	LNG	1	0.003	0.003
CT Natural Gas	LNG	1	0.105	1.142
Southern CT	LNG	1	0.082	1.142
Yankee Gas	LNG	1	0.105	1.200
National Grid (RI)	LNG	2	0.174	2.462
EnergyNorth	LNG	3	0.013	0.013
Northern Utilities	LNG	1	0.006	0.012
Eversource Gas	Propane	4	0.058	0.137
Berkshire Gas	Propane	3	0.008	0.053
Fitchburg Gas	Propane	1	0.011	0.030
EnergyNorth	Propane	3	0.035	0.108
Vermont Gas	Propane	1	0.008	0.015
Total			**1.459**	**16.764**

Compressed natural gas

Several companies operate compression facilities in New England that fill large-capacity truck trailers with CNG.[35] The primary customers for trucked CNG are industrial and large commercial end-users that would not otherwise have access to natural gas. LDCs can also use CNG as a winter peaking resource, or as a source of gas supply for isolated market areas.[36]

CNG can expand the natural gas market by allowing large end-users to switch to gas from another fuel. However, the impact that CNG will have on the New England gas market will depend on where the CNG is produced. When CNG is produced locally, it can increase the need for pipeline capacity to deliver gas into the New England region. CNG facilities that are connected to LDCs (iNATGAS, for example, is a firm sales customer of EnergyNorth) can also increase the requirement for gas supply resources and distribution capacity. Alternatively, CNG that is transported into New England from compression facilities outside the region can be a source of gas supply that reduces the need for pipeline capacity and other sources of supply. For example, XNG has modified its Eliot, ME facility to also receive CNG and inject gas into the M&N/PNGTS joint facilities pipeline.

Renewable natural gas

RNG is pipeline-quality gas that is extracted from landfills, or produced from waste material using anaerobic digesters. Substituting RNG for natural gas is a means of reducing GHG emissions. See Section 8.1. *Non-embedded GHG costs* for a larger discussion on RNG costs and potentials.

Vermont Gas and Summit Natural Gas of Maine (SNGME) have implemented voluntary sales programs under which customers can choose to have a portion of their gas consumption backed by RNG.[37] Both programs currently use RNG that is produced outside of New England.[38]

Several projects are proposed or in development that would supply RNG to New England LDCs:

- An anaerobic digester facility under construction at a dairy farm in Salisbury, VT is expected to deliver 180,000 Mcf per year to Vermont Gas.[39]

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[35] NG Advantage has facilities in Milton, VT and Pembroke, NH. Xpress Natural Gas (XNG) has facilities in Eliot, ME and Baileyville, ME. Innovative Natural Gas (iNATGAS) has facilities in Worcester, MA and Concord, NH.

[36] For example, XNG supplies CNG to EnergyNorth's Keene, NH distribution system.

[37] Summit Natural Gas Maine. Last accessed March 10, 2021. "A Program to help Build a Sustainable Energy Future." *summitnaturalgas.com.* Available at https://www.summitnaturalgasmaine.com/RenewableNaturalGas.

[38] RNG for the Vermont Gas program comes from a landfill in Quebec and a wastewater treatment plant in Iowa. SNGME is buying RNG attributes from a landfill in Oklahoma.

[39] Vanguard Renewables. Last accessed March 10,2021. "Goodrich Farm." *Vanguardrenewables.com.* Available at https://vanguardrenewables.com/portfolio-items/goodrich-farm-salisbury-vt/.

- In August 2020 SNGME received Maine PUC approval to buy up to 146,000 Mcf of RNG per year from Peaks Renewables, Inc., which is developing an anaerobic digester facility at a dairy farm in Clinton, ME.[40]

- In 2018, EnergyNorth asked the New Hampshire PUC to approve an agreement to buy RNG that would be produced at a landfill in Bethlehem, NH. Because of the location of the landfill, the RNG would be compressed, and delivered to EnergyNorth by truck.[41]

2.4. Avoided natural gas cost methodology

AESC 2021 uses the same avoided cost methodology used for AESC 2018, as described below.

Avoidable gas supply costs

Gas supply resources are often 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 uses, where gas is consumed 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 a limited number of days per year. Intermediate resources, such as short-haul pipeline capacity or a winter season gas storage service, are often used to support winter heating requirements.

The avoided natural gas supply cost for an LDC will depend on the characteristics of the gas requirement reduced, and the cost of the marginal resource that would be used to supply each type of load. For example, if the load reduction is limited to commercial and industrial non-heating customers, the avoided cost will usually be the marginal cost of a baseload gas supply resource. For a change in residential heating load, the avoided cost is likely to involve a combination of resources, since the variable gas usage pattern of residential heating customers utilizes a wider range of gas supply resources.

Estimates of the gas supply costs that can be avoided by energy efficiency program savings are calculated for each state, by region, for each of the following end-use categories:

1. Electric generation
2. Commercial and industrial non-heating
3. Commercial and industrial heating

[40] ME PUC Docket No. 2020-00089. SNGME will buy the gas produced by the facility, but not the RNG Attributes. Peaks Renewables is an affiliate of SNGME.

[41] NH PUC Docket No. DG 18-140. EnergyNorth withdrew its application to the NH PUC in February 2020, but did not state that the project has been abandoned.

4. Residential heating
5. Residential water heating
6. Residential non-heating
7. All commercial and industrial
8. All residential
9. All retail end-uses

We provide avoided natural gas values by costing period, allowing readers of AESC to develop more specific avoided costs for other measures not listed above.

Our natural gas avoided cost methodology has three steps.

Step 1 is to identify the marginal gas supply resource for each load type (i.e., baseload, intermediate, or peaking). For electric generation, we assume the applicable natural gas cost is the New England wholesale market price. For the retail end-use categories, we examine the existing and potential gas supply resources that would potentially be the marginal source of supply.

For each resource that could potentially be increased or decreased in response to a change in gas requirements, we then estimate the total delivered cost of the resource for each costing period, expressed in $/MMBtu/year. We exclude unavoidable costs. The marginal resource for each costing period is assumed to be the resource with the lowest delivered cost over the forecast horizon.

Step 2 is to determine the percentage of load for each end-use type that corresponds to each costing period. For all states except Vermont, we use the same six costing periods used in AESC 2018 as detailed below:[42]

1. Highest 10 days
2. Highest 30 days
3. Highest 90 days
4. Winter (November-March)
5. Winter/Shoulder (All months except June-August)
6. Annual Baseload

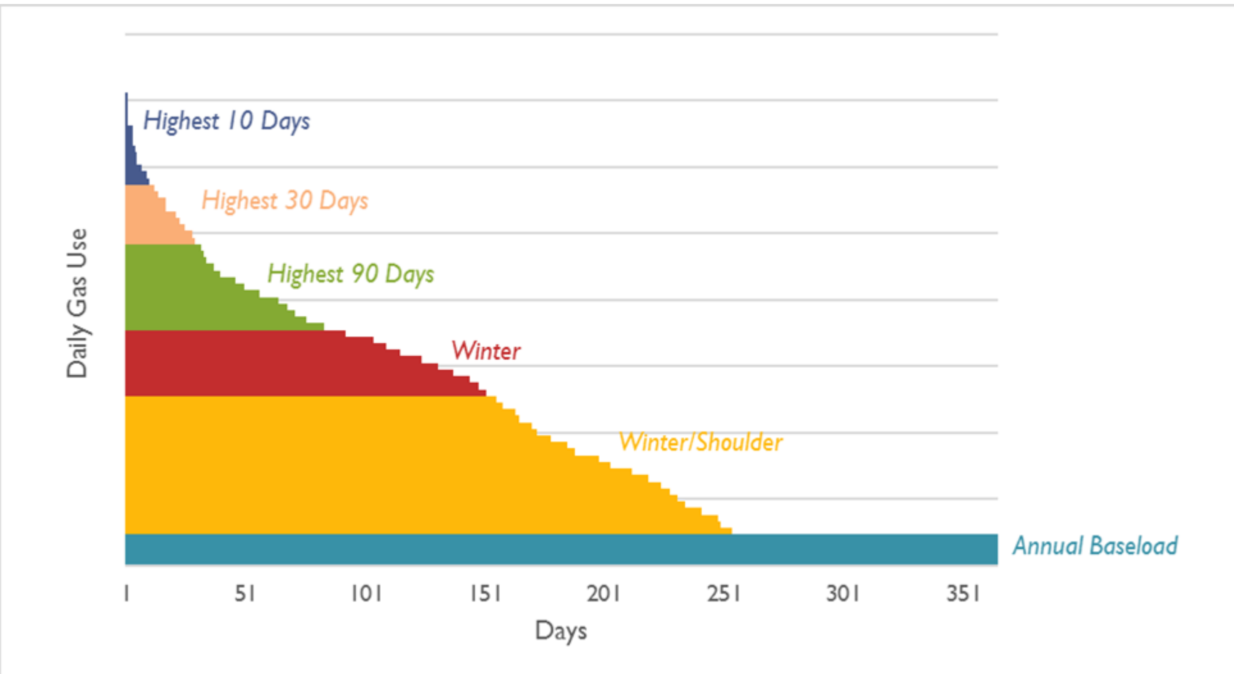
These costing periods generally correspond to the different types of gas supply resources that New England LDCs acquire to meet projected end-use requirements. Requirements that extend through the

[42] For Vermont, natural gas avoided costs are estimated for four time-of-use costing periods: peak day, next highest nine days, remaining winter (141 days), and summer/shoulder (214 days).

Annual Baseload and Winter/Shoulder periods are typically met with pipeline capacity from outside the region. Winter period requirements, and gas requirements that must be met at least 90 days per year, are often supplied using pipeline capacity from New England supply points or contracts for delivered gas. The shorter-duration requirements are typically supplied using on-system peaking resources and contracts for delivered peaking supplies.

The load shares for each end-use type are calculated from a load curve that combines a representative gas use equation (base use per day and use per heating degree day, or HDD) and a representative HDD distribution. This is illustrated by Figure 7, which shows a sample load curve for the Commercial and Industrial Heating end-use category. The load share for the Winter costing period, for example, is based on the amount of gas use that occurs at least 151 days per year, minus the gas use that only occurs on the highest 90 days. A resource that supplies planning load requirements during the Winter costing period would be used an average of 120 days per year, which corresponds to an annual load factor of 33 percent.

Figure 7. Illustrative commercial and industrial heating load shape



Step 3 is to multiply the marginal resource cost for each costing period by the corresponding load percentages. Summing the results over all costing periods gives the total annual avoided cost for each end-use. This calculation is repeated for each end-use type, for each year of the forecast period as illustrated in Table 5.

Table 5. Illustrative avoided cost calculation

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
ILLUSTRATIVE AVOIDED COST FOR THIS END-USE TYPE →			**$6.25**

Assumptions and data sources

The following sections contain information about the assumptions and data sources used to construct avoided natural gas costs for New England.

New England regions

Natural gas avoided costs are estimated for three regions: (1) southern New England (Connecticut, Rhode Island, and Massachusetts); (2) northern New England (New Hampshire, Maine); and (3) Vermont.

Load shares

The load shares used for the avoided cost calculation are based on a representative HDD distribution, as well as base use per day and use per HDD factors by end-use category that were provided by study sponsors.[43] The same load share factors are used for all regions. The proportions of baseload and temperature-sensitive gas use for the five end-use categories are shown in Table 6.

Table 6. Base use and heating factors by end-use

End-use	Base use (Percent)	Temperature sensitive (Percent)
Residential Heating	-	100%
Residential Water Heating	69%	31%
Residential Non-Heating	100%	-
Commercial & Industrial Heating	21%	79%
Commercial & Industrial Non-Heating	68%	32%

Natural gas transmission costs

For AESC 2021, transmission costs are measured using the rates that New England LDCs pay to upstream pipelines for firm transportation services. These rates include a fixed reservation charge that is applied

[43] This assumes that the daily temperature distributions for the New England states are similar, even though the total annual HDDs are different in each state.

to the daily contract quantity and a variable charge that is applied to the quantity of gas transported. Pipelines also retain a percentage of the gas transported for compressor fuel and for "lost and unaccounted for" gas (see page 46).

Because the cost to build new pipeline facilities is generally higher than the costs of the depreciated assets that are used to set the pipelines' standard cost of service rates, interstate pipelines usually charge higher "incremental" rates for new services to avoid subsidization by the pipeline's other shippers. Shippers that participate in pipeline expansion projects often enter into negotiated rate agreements that set the transportation rate over the initial contract term.

The avoided cost estimates in AESC 2021 assume that LDCs can adjust the amount of transmission service they have under contract when customer requirements change. In a market such as New England, where natural gas use by LDC planning load customers is projected to increase, energy efficiency measures that reduce gas use should cause future pipeline expansions to be smaller.[44] For pipelines that price new capacity using incremental rates, the avoided transmission cost is the actual or proposed rate for the applicable pipeline's most current mainline expansion project. For the Canadian pipelines, which do not charge incremental rates for new capacity, the avoided cost is measured by the tariff rate.

Gas resource options for AESC 2021

Based on our review of New England LDC forecasts and resource plans, and other public material filed with state regulators, we assume that LDCs will obtain additional gas supplies using a combination of the representative gas resource options described here:

<u>Resource 1: Dawn Hub supply via TCPL</u>

This supply option includes Enbridge Gas transportation service from the Dawn Hub to TCPL, TCPL service to PNGTS, and service on PNGTS to Dracut. LDCs in southern New England also contract for TGP service to move gas Dracut to their city gates.

Vermont Gas currently obtains all pipeline-delivered gas supplies from the Dawn Hub and other Ontario points through its direct connection to TCPL. We assume that this will continue.

The costs for this option are based on Enbridge Gas and TCPL 2021 transportation rates and projected PNGTS expansion costs (see Table 7). Pipeline costs include the fixed reservation charge, shown as an average cost per MMBtu, the variable transportation charge, and the percentage of the natural gas transported that the pipeline retains for compressor fuel and unaccounted-for gas (see page 46). The gas commodity cost is the projected Dawn Hub price.

[44] See Table 3 for a list of recent and planned pipeline expansion projects.

Table 7. Transmission costs for the Dawn Hub capacity path

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
Enbridge Gas	Dawn Hub	Parkway	0.099	0.0	0.8%
TCPL	Parkway	VGS	0.446	0.0	0.9%
TCPL	Parkway	PNGTS	0.569	0.0	1.5%
PNGTS	TCPL	Dracut	0.854	0.0	0.7%
TGP	Dracut	TGP Zone 6	0.137	0.029	0.1%

Resource 2: Marcellus supply via AGT

This pipeline capacity path extends from the Marcellus shale gas producing areas in Western Pennsylvania to New England markets. The costs for this path include the Millennium Pipeline transportation costs from the Marcellus area to Ramapo, NY, and the incremental rates charged for Atlantic Bridge expansion project for transportation from Ramapo to New England. For northern New England, there are additional transportation costs on MNP to deliver gas from the end of the AGT system to markets in New Hampshire and Maine (see Table 8). The TETCO M2 index is used as the representative price for Marcellus-area gas supply received by Millennium Pipeline.

Table 8. Transmission costs for the Marcellus capacity path

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
Millennium	Marcellus	Ramapo	0.583	0.002	1.4%
AGT	Ramapo	Salem	1.805	0.0	2.6%
MNP	Salem	NH or ME	0.522	0.0	0.9%

Resource 3: Dracut supply via TGP (southern New England)

Gas is purchased at Dracut, where TGP connects with MNP and PNGTS, and is transported on TGP to the LDC city gate (see Table 9). LDCs are assumed to contract for winter season supply priced at the AGT Citygates index plus a fixed premium.

Table 9. Transmission costs for Dracut supply

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
TGP	Dracut	TGP Zone 6	0.137	0.029	0.1%

Resource 4: Delivered gas supplies (northern New England)

The northern New England LDCs that are connected to MNP and PNGTS contract for firm gas winter-season gas supply delivered at their citygates. We assume that the delivered gas cost is the AGT Citygates price plus a fixed premium.

Resource 5. On-system peaking resources (northern New England and Vermont)

The larger LDCs in northern New England (Northern Utilities and EnergyNorth) use LNG trucked to satellite peaking facilities to meet winter gas requirements. When peak-period requirements increase, these LDCs contract for additional LNG supplies to cycle their limited on-site LNG storage capacity. These

LDCs are also considering new LNG facilities to meet future increases in peak day demand. We assume that the cost of gas from an LNG peaking facility is the average AGT Citygates price for the peak winter months, plus a fixed premium. The peaking costs for Vermont are based on a forecast of propane prices.

Other sources of natural gas supply

There are other sources of natural gas supply that do not enter into the AESC 2021 avoided cost calculations.

Underground gas storage

Most New England LDCs hold contracts for seasonal storage service from underground gas storage facilities located in New York, Pennsylvania, and Ontario. With the growth of Marcellus shale gas production, underground storage is used less as a gas supply resource and more as a price hedging and operational balancing tool. Based on our review, LDC decisions to renew or terminate these contracts do not appear to be closely tied to changes in projected customer requirements. As with AESC 2018, we do not include storage service costs in the natural gas avoided cost estimates.

Compressed natural gas

Our review of New England LDC forecasts and supply plans found that several LDCs are considering CNG as a future gas supply resource, but we did not find evidence that CNG is expected to have a significant impact on these LDCs' gas supply costs.

Renewable natural gas

RNG is both a physical gas supply resource and a means of meeting GHG reduction goals. As a supply resource, several projects that would inject RNG into New England LDC distribution systems are proposed, or in active development (see Section 2.3. *New England natural gas market* for additional information). Connecticut LDCs are required to have standard RNG interconnection rules to facilitate future RNG production in that state.[45] However, because RNG is valued for its environmental benefits, RNG is not expected to be a marginal supply resource with production that varies with changes in gas consumption. For this reason, local RNG production is not included as a physical supply resource for the AESC 2021 avoided cost calculations.

There is also a market for RNG attributes. Vermont Gas recently began including the cost of purchasing RNG attributes in the cost of gas adjustment.[46] The VGS Climate Plan includes a goal of reducing GHGs by 30 percent by 2030. To reach this goal, VGS estimates that approximately 20 percent of its retail gas supply will need to be RNG. This includes RNG acquired for its voluntary sales program, and RNG attribute purchases that are included in system gas supply. Because VGS' RNG attribute purchases are

[45] CT PURA Docket No. 19-07-04.

[46] VT PUC Case No. 20-0431-TF, Direct Testimony of Todd Lawliss, p. 12.

tied to increases or decreases in customer requirements, RNG costs are included in the avoided costs for Vermont.

Lost and unaccounted for gas

The total quantity of gas measured at customer meters is generally lower than the measured quantity 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 2 percent. LAUF causes the gas requirement at the LDC citygate to be slightly greater than the amount delivered to customers, which increases gas supply costs. We use a LAUF factor of 1.75 percent for all regions outside of Vermont, and a 1.0 percent LAUF factor for VGS.

Natural gas distribution margin

Natural gas distribution systems are designed to meet the projected peak hourly requirements of the LDC's firm customers. When gas use is increasing, LDCs expand capacity by adding new mains, by replacing existing mains with larger-diameter pipe, or by replacing older mains with pipe that can be operated at a higher pressure. Efficiency measures that lower peak gas use avoid the cost of new facilities and associated increases in operation and maintenance (O&M) costs.[47]

LDC marginal cost studies use econometric analysis and engineering estimates to calculate the relationship between expenditures for plant and O&M and changes in peak day demand. The results from these studies are used to design rates and to set floors for the rates charged under special contracts. For AESC 2021 we use the results from recent marginal cost studies prepared by New England LDCs. These are presented in Table 10, which also shows the avoidable LDC margins for southern New England that were used for AESC 2018.[48]

[47] Some mains-replacement projects reduce leakage risk and hence maintenance costs; it is not clear to what extent load growth results in more mains replacement, as opposed to changes in the order of replacements.

[48] AESC 2018 used marginal costs from a recent LDC rate case to estimate the portion of the distribution rate for each class of customer that was related to changes in system capacity. These percentages were then applied to average distribution margins for each New England region. Average distribution margins were calculated by subtracting the citygate natural gas price from the residential, commercial, and industrial prices that are reported by EIA for each state.

Table 10. Marginal distribution capacity cost by customer class (2021 $ per MMBtu)

Company	Docket Number	Residential		Commercial / Industrial		Annual Use (Bcf)
		Non-Heating	*Heating*	*High Load Factor*	*Low Load Factor*	
National Grid (Boston Gas)	17-170	0.960	1.327	0.861	1.391	95.4
National Grid (Colonial Gas)	17-170	1.000	1.418	0.960	1.511	23.8
Berkshire Gas	18-40	0.959	1.518	0.661	1.531	7.6
Eversource Gas	18-45	0.453	0.694	0.387	0.744	51.8
NSTAR Gas	19-120	1.521	2.205	1.128	2.122	51.7
EnergyNorth	DG 20-105	0.937	1.607	0.544	1.597	15.7
Northern - Maine	2019-00092	0.635	0.817	0.301	0.708	10.8
Weighted Average		0.96	1.39	0.78	1.41	
AESC 2018 (2018 $/MMBtu)		0.33	1.09	0.42	0.75	
AESC 2018 (2021 $/MMBtu)		0.35	1.15	0.44	0.79	

2.5. Avoided natural gas costs by end-use

A summary of the natural gas avoided cost estimates is shown in Table 11, Table 12, and Table 13. Avoided costs are developed for three regions: southern New England (Connecticut, Massachusetts, Rhode Island), northern New England (Maine, New Hampshire), and Vermont. Vermont is shown separately because it uses a different avoided gas cost methodology. The results are shown with and without the avoided LDC margin and are compared to the values from AESC 2018.

Table 11. Avoided costs of gas for retail customers by end-use assuming no avoidable margin (2021 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end-uses
	Non Heating	*Hot Water*	*Heating*	*All*	*Non Heating*	*Heating*	*All*	
Southern New England								
AESC 2018	$6.16	$8.09	$8.64	$8.16	$6.98	$8.12	$7.62	$7.91
AESC 2021	$4.67	$5.52	$7.42	$6.63	$5.60	$6.86	$6.31	$6.48
2018 to 2021 change	*-24%*	*-32%*	*-14%*	*-19%*	*-20%*	*-15%*	*-17%*	*-18%*
Northern New England								
AESC 2018	$5.95	$7.74	$8.24	$7.80	$6.71	$7.77	$7.31	$7.57
AESC 2021	$4.51	$5.39	$7.38	$6.55	$5.48	$6.79	$6.22	$6.39
2018 to 2021 change	*-24%*	*-30%*	*-11%*	*-16%*	*-18%*	*-13%*	*-15%*	*-16%*

Notes: AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

Table 12. Avoided costs of gas for retail customers by end-use assuming some avoidable margin (2021 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end-uses
	Non Heating	*Hot Water*	*Heating*	*All*	*Non Heating*	*Heating*	*All*	
Southern New England								
AESC 2018	$6.51	$8.31	$9.66	$9.04	$7.37	$8.79	$8.17	$8.61
AESC 2021	$5.63	$6.48	$8.81	$7.86	$6.38	$8.27	$7.45	$7.67
2018 to 2021 change	*-14%*	*-22%*	*-9%*	*-13%*	*-13%*	*-6%*	*-9%*	*-11%*
Northern New England								
AESC 2018	$6.28	$8.06	$9.30	$8.73	$7.01	$8.30	$7.73	$8.06
AESC 2021	$5.47	$6.35	$8.76	$7.79	$6.26	$8.19	$7.35	$7.58
2018 to 2021 change	*-13%*	*-21%*	*-6%*	*-11%*	*-11%*	*-1%*	*-5%*	*-6%*

Notes: AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

Table 13. Avoided costs of gas for retail customers by end-use for Vermont (2021 $ per MMBtu)

	All sectors			
	Design Day	*Peak Days*	*Remaining Winter*	*Shoulder/ Summer*
Vermont				
AESC 2018	$591.58	$27.68	$5.15	$4.72
AESC 2021	$556.10	$17.08	$5.11	$4.75
2018 to 2021 change	*-6%*	*-38%*	*-1%*	*1%*

Notes: AESC 2018 levelized costs are for 15 years (2018–2032) at a discount rate of 1.34 percent. AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent.

Southern New England and Northern New England

The AESC 2021 avoided cost estimates are lower than the AESC 2018 estimates, but the change in the avoided costs is not as large as the change in the Henry Hub and Algonquin Citygate commodity price forecasts. The main reason is that the cost of expanding natural gas pipeline capacity into New England continues to rise. For AESC 2021, the incremental cost to expand capacity on PNGTS is assumed to be $0.85 per MMBtu, which is 40 percent higher than the transportation charge that was used for AESC 2018. The final rates charged for AGT's Atlantic Bridge expansion project are 14 percent higher than the previous estimate. Because pipeline operators recover capital costs and most operating costs through a fixed monthly charge, the impact of the higher incremental pipeline charges is amplified for lower load factor end-uses, such as residential heating.

Comparing the two Southern New England and Northern New England regions, because the marginal gas transmission path used to calculate the avoided costs for both northern New England and southern New England runs from the Dawn Hub in Ontario through northern New Hampshire, additional gas pipeline charges cause the avoided costs for southern New England to be slightly higher. However, the difference in avoided costs between southern New England and northern New England is smaller for AESC 2021 than for AESC 2018.

Vermont

The natural gas avoided cost estimates for Vermont use the end-use costing periods and methodology developed for previous AESC studies. The Design Day avoided cost is the marginal upstream supply and delivery cost, plus the marginal LDC transmission cost. The Canadian pipeline tolls that set the upstream delivery costs for VGS are slightly lower for AESC 2021 than for AESC 2018, due in part to the change in the Canadian dollar exchange rate. The avoided cost for the remaining nine Peak Days reflects the lower delivered cost of propane for the VGS 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 2021, compare those estimates with AESC 2018, and identify the data sources used.

This section analyzes oil prices in $/MMBtu for the four sectors: electric generation, residential, commercial, and industrial. Prices are developed for the following grades: distillate fuel oils (No.2 and No. 4), residual fuel oils (No. 6), and biofuel blends.[49] Also included are cord wood, wood pellets, kerosene, and propane in the residential heating applications. New to AESC 2021, we also investigate avoided costs for motor gasoline and diesel used for transportation.

In general, we find that avoided levelized costs for all fuels considered in this category are moderately higher than what was estimated in AESC 2018. In AESC 2021 we follow the EIA Short Term Energy Outlook (STEO) for one year and then directly transition to the 2021 AEO forecast. We chose these data sources for the near term to represent current market conditions and to capture the effects of the COVID-19 pandemic. In contrast, in AESC 2018 we followed the STEO and NYMEX market futures for two years and then transitioned over several years to the most recent AEO forecast.

3.1. Results and comparison with AESC 2018

Table 14 compares the levelized avoided fuel costs for AESC 2021 with those used for AESC 2018. Annual avoided fuel costs are detailed in Appendix D: *Detailed Oil and Other Fuels Outputs*. The Synapse Team based the results for the oil-based fuels on the most recent New England State Energy Data System (SEDS) prices. We then adjusted the results based on the crude oil price trends as discussed above and the AEO 2020 Reference Case projections for New England. Residential distillate prices are 2.9 percent greater, while Commercial distillate prices are 14.3 percent higher and commercial residual prices are 8.2 percent lower (this decrease is due to a drop in recent historical prices for this fuel product). Propane prices are higher, representing recent increases in the SEDS price data. Kerosene, a fuel with a very modest market share, shows a significant increase based on the most recent SEDS data with a price midway between that of distillate and propane.

Wood pellet prices are about the same, reflecting current market conditions. Cord wood, whose price and quality can vary widely, shows a significant price increase based on recent prices. However, these prices are below those of wood pellets. Note that all these prices reflect the fuel heat content and do not adjust for relative efficiencies and delivered energy. This analysis uses SEDS values for the starting points, adjusted for current and near-term national prices from STEO. The prices then follow the trajectory of the AEO 2021 Reference case prices going forward.[50]

[49] For the purposes of AESC 2021, biofuels blended in heating oil include B5 and B20.

[50] See https://www.eia.gov/state/seds/ for more information about the EIA State Energy Data System (SEDS).

Table 14. Comparison of avoided costs of retail fuels (15-year levelized, 2021 $ per MMBtu)

	Residential						Commercial		Transportation	
	No. 2 Distill-ate	Pro-pane	Kero-sene	Bio-Fuel (B20)	Cord Wood	Wood Pellets	No. 2 Distillate	No. 6 Resid-ual	Motor Gasoline	Motor Diesel
AESC 2018	$23.36	$32.78	$20.95	$24.06	$14.12	$22.76	$19.46	$17.13	-	-
AESC 2021	$24.04	$38.79	$29.59	$21.64	$20.84	$22.47	$22.25	$15.74	$22.07	$22.76
Percent change	2.9%	18.3%	41.3%	-10.1%	47.6%	-1.3%	14.3%	-8.2%	-	-

3.2. Forecast of crude oil prices

The primary factor driving avoided fuel oil costs and fuel oil prices is the price of crude oil. For AESC 2021, we rely on EIA's STEO and projections from the 2021 AEO Reference case (see Chapter 0:

Avoided Natural Gas Costs for more information about the analogous gas price forecast). This is a similar methodology to that used in the 2018 AESC study.

For near-term projections in AESC 2021, we rely on data from the most recent STEO forecast for West Texas Intermediate (WTI) crude oil. We then transition to the AEO 2021 Reference case price projections in 2022. The approach is similar to that used for the natural gas price forecast, but it differs in that the markets have different sources of production and distribution. The oil markets are much more global and fluid than those for natural gas.

The COVID-19 pandemic has reduced fossil fuel consumption world-wide and prices have fallen as supply exceeds demand. In the January 2021 edition of the STEO, the oil price forecast is about $45 per barrel through 2022. However, the uncertainty is quite large, as shown in Figure 8. We also reviewed the NYMEX oil futures for WTI (see Figure 9), which were occasionally used in past AESC studies to adjust or to verify the forecast. These values are similar to the January 2021 STEO in the near term, but then decline in both nominal and real dollar terms. This is odd market behavior and probably not indicative of likely future prices. Thus we make no use of this information in AESC 2021. For short-term prices, we ultimately rely on the STEO forecast because that incorporates an informed analysis of a wide variety of data, including the futures.[51]

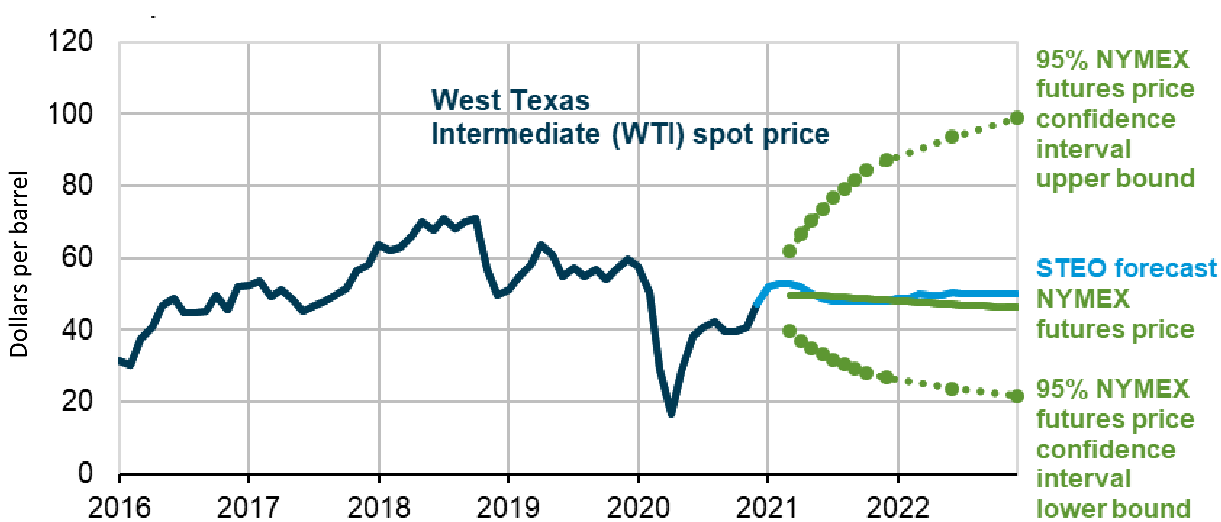
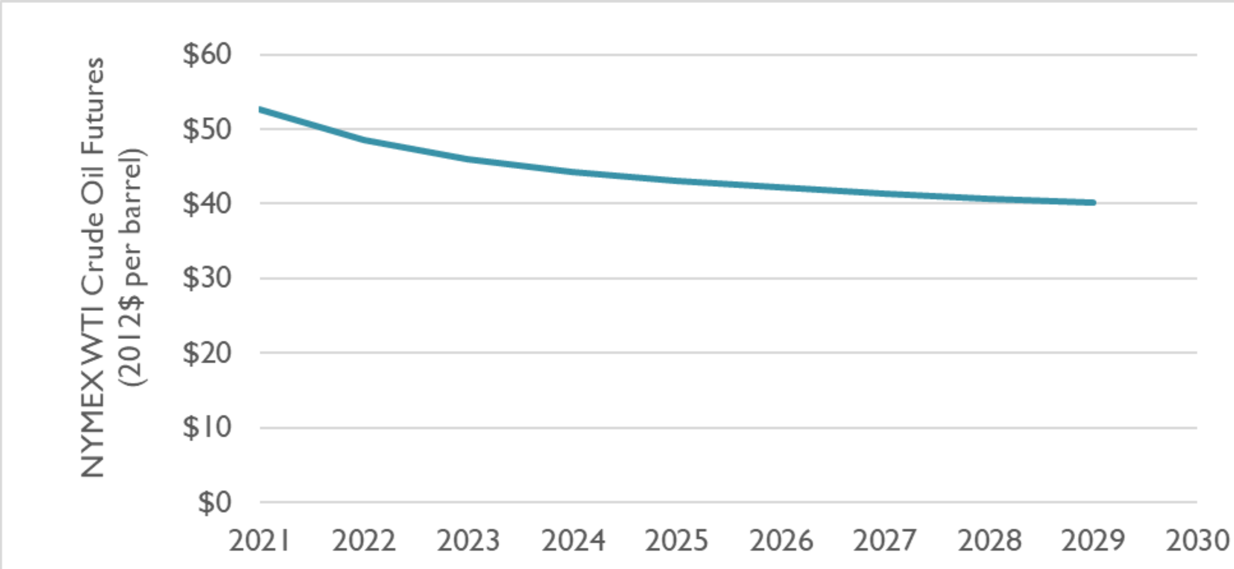


Figure 8. Forecast for West Texas Intermediate crude oil with NYMEX confidence intervals

Source: Reproduced from the January 2021 edition of EIA's Short-Term Energy Outlook. Available at *https://www.eia.gov/outlooks/steo/* *Retrieved January 30, 2021. EIA note: "Confidence interval derived from options market information for the five trading days ending Jan 7, 2021. Intervals not calculated for months with sparse trading in near-the-money options contracts."*

[51] U.S. EIA. Last accessed March 10, 2021. "Short Term Energy Outlooks" *eia.gov.* Available at https://www.eia.gov/outlooks/steo/marketreview/crude.php.

Figure 9. NYMEX oil futures for West Texas Intermediate (WTI) crude oil

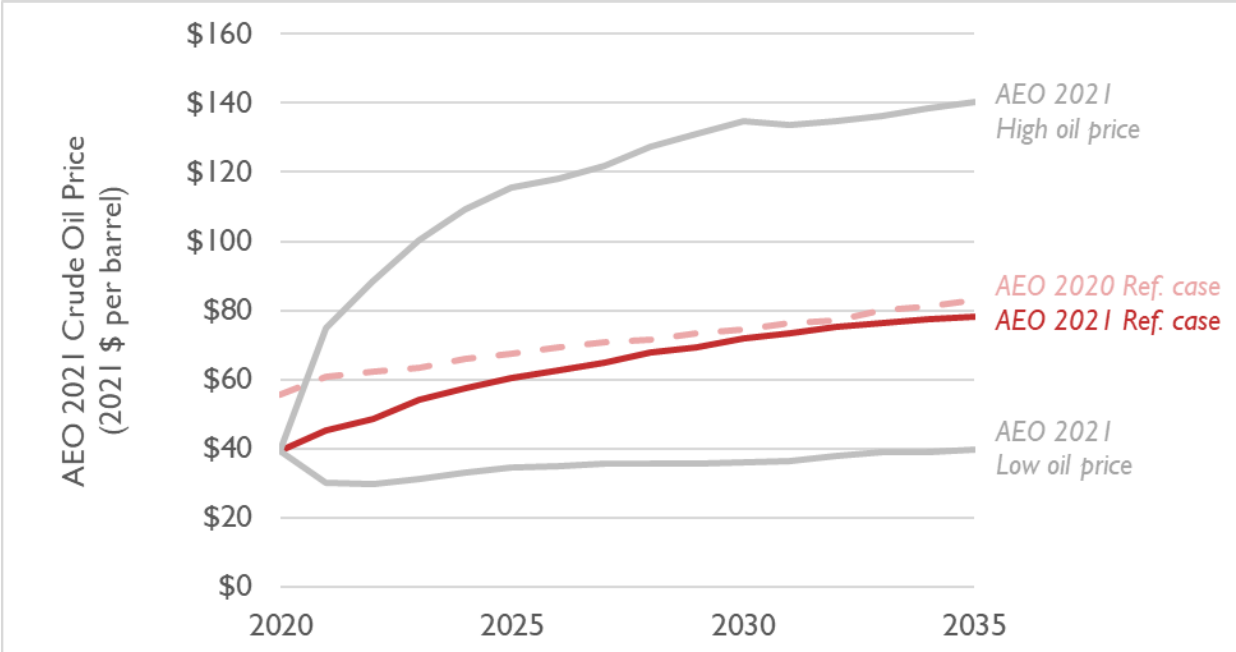


Source: CME Group, https://www.cmegroup.com/market-data/settlements.html?redirect=/market-data/settlements/index.html, Retrieved February 2, 2021.

Figure 10 shows prices for WTI crude oil from a number of scenarios in AEO 2021.[52] Oil prices rise modestly in the Reference case but differ substantially in the High and Low Oil Price scenarios. This represents the uncertainty about future oil prices. The 2020 price of oil in AEO 2021 (about $40 per barrel) is about two-thirds the price projected in AEO 2020 but increases up to similar levels by 2030.

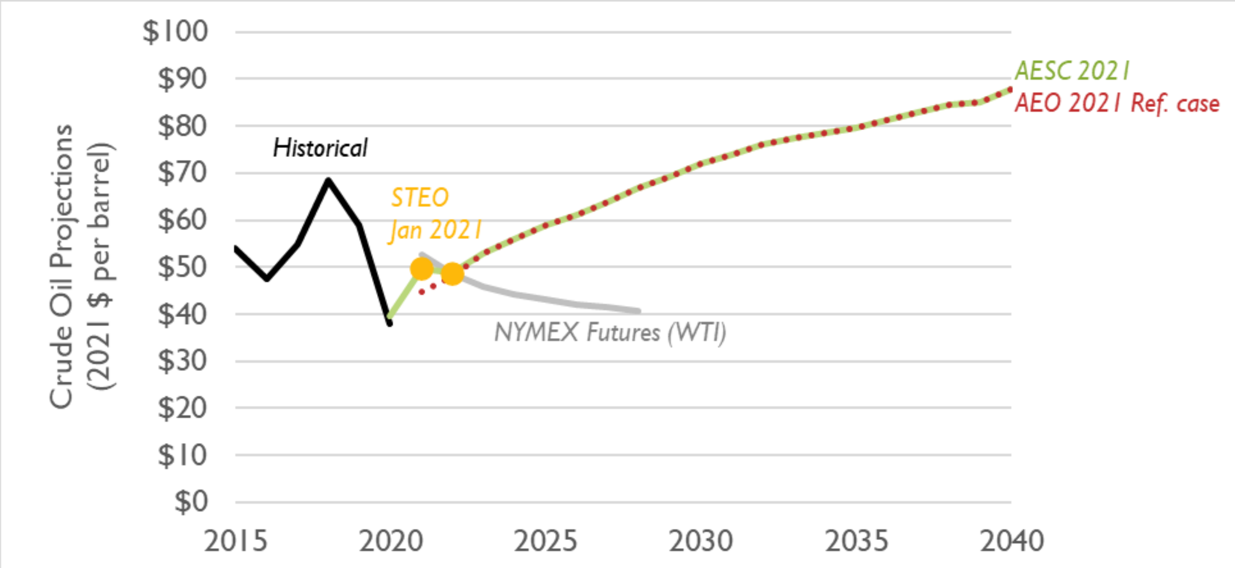
[52] AEO 2020 does not present WTI crude oil prices. Price shown for AEO 2020 is for Brent.

Figure 10. Oil prices projected in various AEO 2021 scenarios



The current short-term forecasts and futures markets do not indicate much increase in crude oil prices over the next several years. However, AEO projections are based on fundamental resource base analyses, and thus it is reasonable to expect higher future oil prices in the medium to long term. For AESC 2021, we use STEO for the near term (2021) and AEO 2021 for the medium and long terms (2022 and all subsequent years) (see Figure 11). The annual real rate of price increase is about 2 percent per year. This forecast is not meant to predict the actual price in any given year, but rather to represent a mid-point average of fluctuating prices.

Figure 11. Crude oil prices, historical, forecast, and AESC 2021



3.3. Forecast of fuel prices

For AESC 2021, starting prices for fuel prices for electric generation and other end-uses are based on historical prices for the various fuels and sectors from SEDS (see Table 15). SEDS represents a comprehensive compilation of the actual prices and consumption. For the electric sector, we verify this with the EIA database of fuel costs for electric generation. Investigation of recent wood prices found delivered wood pellets to be in the range of $18 per MMBtu.[53] Prices for cord wood and wood chips at the residential level are not readily available and vary widely both in cost and heat value.

Data in EIA's SEDS database is provided at the state level. We looked at nine years (2010–2018) of historical data to determine if there are significant variations between the New England states. No consistent and significant state variations are apparent, and except for propane, prices in New England closely resemble national average prices.

[53] New Hampshire Office of Strategic Initiatives. "Fuel Prices," accessed August 31, 2020. Available at: https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm.

Table 15. SEDS New England fuel prices in 2018 by end-use sector in 2018 (2021 $ per MMBtu)

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	20.8	20.2	19.0	24.8	16.6
Kerosene	25.6	25.6	16.0	-	-
LPG (Propane)	36.8	19.0	20.2	19.8	-
Residual fuel oil	-	11.6	13.9	-	7.9
Motor Gasoline	-	24.4	24.4	24.4	-
Wood	17.9	-	-	-	-
Wood & Waste	-	22.4	22.4	-	-

AEO 2021 and other EIA documents do not generally make a distinction between state-level prices for specific grades of fuel oil. Instead, they simply report on high-level categories of Distillate Fuel Oil and Residual Fuel Oil. However, the grade mix between sectors does vary and is reflected to some degree in the prices for those sectors.

In terms of the AESC grade categories, we use 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. Definitions of the EIA fuel oil categories can be found on the EIA website.[54] This is the same mapping applied in the 2018 AESC Study.

AEO 2021 does not provide a forecast of New England regional prices for biofuel B5 and B20 blends, 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., soybeans). 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 GHG emissions per MMBtu of fuel consumed,[55] more efficient operation of furnaces, and less reliance on imported crude oil. Their disadvantages include somewhat lower heat contents, equipment effects, 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.[56, 57] 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 $0.90 per gallon, or an implied 7 cents per gallon for

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

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

[56] ASTM International. “ASTM Sets the Standard for Biodiesel.” Jan 2009. Available at: http://www.astm.org/SNEWS/JF_2009/nelson_jf09.html.

[57] “Below the rack” refers to blending at the refinery, before fuel is sold to wholesalers.

the B5 blend. However, the current price for B20 is $0.25 per gallon below diesel ($2.36 vs. $2.61).[58] B20 prices have been below diesel prices by similar levels since 2018. We thus project that B20 prices will be 10 percent below diesel prices in the future, and that B5 prices will have neither a discount nor a premium.

The SEDS data show no differences in residential wood prices between the New England states. As the starting basis for wood prices, AESC 2021 uses recent data from New Hampshire.[59] Actual wood prices and wood quality can vary widely, and we recommend that anyone interested in this issue carry out an independent investigation of local wood prices. In previous AESC studies, we linked the future wood fuel price changes to that of distillate oil and we do so again here.

Because recent oil prices have changed so much since the 2018 SEDS data, we adjusted those prices to represent the changes in oil prices since then. The AESC 2021 starting prices are shown in the following table.

Table 16. New England fuel prices in 2021 by end-use sector (2021 $ per MMBtu)

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	19.1	20.9	20.0	20.0	18.5
Kerosene	23.6	26.4	16.8		
LPG (Propane)	33.9	19.7	21.2	15.9	
Residual fuel oil	-	12.0	14.6		8.8
Motor Gasoline	-	25.3	25.6	19.7	
Wood	17.9				
Wood & Waste	-	23.2	23.6		

Prices in future years start with the base year prices as indicated above and then increase following the trajectory for the oil price forecast, as shown in Figure 11. They then follow that same relative trajectory and match the AEO 2021 New England price projections and trends in 2022 and future years. The AESC 2021 starting prices are based on 2018 SEDS historical data and actual 2020 prices, but the changes over the analysis period are based on the AEO projections.[60]

Since fuel oil prices do not show meaningful variations by month or season, we have not developed monthly or seasonal price variations for petroleum products. Storage for petroleum products is relatively inexpensive and this also tends to smooth out variations in costs relative to market prices. For these reasons, our forecast does not address volatility in the prices of these fuels.

58 U.S. Department of Energy Alternative Fuels Data Center, April 2020 prices. https://www.afdc.energy.gov/fuels/prices.html.

59 New Hampshire Office of Strategic Initiative, "Fuel Prices." Available at https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm. Accessed August 31, 2020.

60 In cases where there are noticeable differences between the SEDS and the AEO prices we have relied on the SEDS prices, as these represent actual reported costs.

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 2021. The consumption of these fuels is not expected to increase significantly over the study period. Moreover, the supply systems are flexible and diverse, and they are not subject to the capacity- or time-based constraints associated with electricity and natural gas. Thus, we believe 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. Consistent with prior AESC studies, we model the full cost of those fuels as avoidable.

3.5. Greenhouse gas and criteria pollutant emissions

Table 17 provides carbon dioxide (CO_2) emission rates for the various fuels analyzed in this chapter. This table defines the CO_2 emission rate for wood fuels as zero. This essentially a placeholder value, as there are differing views about the GHG impacts of wood fuels. Additional information on emissions rates can be found in Appendix G: *Marginal Emission Rates and Non-embedded Environmental Cost Detail*.

Table 17. CO_2 emission rates for non-electric fuels (lb per MMBtu)

Fuel	CO_2 Emission Rate
Distillate fuel oil	161
B5 Biofuel	153
B20 Biofuel	129
Kerosene	159
LPG	139
RFO	173
Transportation Diesel	161
Gasoline	157
Wood	zero
Wood & Waste	zero

Note: 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. Version February 2016.
Sources: Emission rates for petroleum products from EIA https://www.eia.gov/environment/emissions/co2_vol_mass.php.

Combustion of these fuels also produces sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions. Most of the available emission data is quite old and the impacts are very small. However, for reference we provide the emission rates from AESC 2018 (see Table 18). 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.[61] By contrast, 1 percent sulfur oil—historically in wide use in New England—contains 10,000 ppm of sulfur. The shift to ULSD reduces the SO_2 emissions by a factor of over 600. Distillate oil at 15 ppm sulfur is equivalent to 0.0016 lb SO_2 per MMBtu, which rounds to the 0.002 lb SO_2 per MMBtu, shown in Table 18. Heavier oils will likely have higher sulfur content and the emission rates should be adjusted accordingly based on their actual characteristics.

Table 18. SO_2 and NO_X emission factors (lb per MMBtu)

Emission Rates of Significant Pollutants from Fuel Oil Sector and Fuel	SO_2	NO_X	*Notes*
#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	0.152	0.129	*(b)*
Wood—Residential heating	0.020	0.341	*(c)*

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.

The table below provides emission assumptions for gasoline and diesel used in transportation. Note that criteria pollutants from the transportation sector can vary substantially based on vehicle type and age. These numbers are based on national averages for vehicles on the road in 2018 and may change as new vehicle emission standards are implemented in the future and older vehicles are retired.

Table 19. Transportation fuel emission factors (lb per MMBtu)

Fuel	NO_x	HC	CO	PM2.5 (Exhaust)	PM2.5 (Brake and Tire)
Gasoline	0.124	0.137	1.620	0.003	0.001
Diesel	0.717	0.077	0.239	0.026	0.002

Notes: NO_X = nitrogen oxides; HC = hydrocarbons; CO = carbon monoxide; PM2.5 = particulate matter with diameter <= 2.5 micrometers. Gasoline includes light-duty vehicles, light-duty trucks, and motorcycles. Diesel includes trucks of six tires or more. combination trucks, and buses.
Sources: Derived from the National Transportation Statistics tables of the Bureau of Transportation Statistics of the U.S. Department of Transportation. Available at https://www.bts.gov/product/national-transportation-statistics. See Tables 1-35, 4-43, and 4-6M.

[61] U.S. EIA. April 18, 2012. "Sulfur Content of Heating Oil to be Reduced in Northeastern States." *eia.gov.* Available at https://www.eia.gov/todayinenergy/detail.php?id=5890.

Vehicle emission rates vary at the state level for a variety of factors including vehicle mix and inspection programs (for example, see the data in Table 20).[62] U.S. Department of Transportation does not publish state emission data, but this data may be available from state transportation or environmental agencies.[63]

Table 20. Transportation fuel 2018 emission factors (grams per mile)

Pollutant	Gasoline				Diesel		
	Light-duty vehicles	*Light-duty trucks*	*Heavy-duty vehicles*	*Motor-cycles*	*Light-duty vehicles*	*Light-duty trucks*	*Heavy-duty vehicles*
HC	0.350	0.421	1.160	2.544	0.183	0.324	0.645
CO	3.941	5.655	21.352	13.58	2.663	2.754	1.994
NO_X	0.289	0.478	1.416	0.719	0.153	1.321	5.971
Exhaust $PM_{2.5}$	0.008	0.010	0.030	0.024	0.004	0.045	0.213
Brakewear $PM_{2.5}$	0.003	0.003	0.009	0.001	0.003	0.003	0.013
Tirewear $PM_{2.5}$	0.001	0.001	0.002	0.001	0.001	0.002	0.004

Sources: Derived from the National Transportation Statistics tables of the Bureau of Transportation Statistics of the U.S. Department of Transportation. Available at https://www.bts.gov/product/national-transportation-statistics. Table, 4-43.

[62] In addition, there may be volatile organic compound (VOC) emissions from fuel oil handling and from wood fuel combustion. These emissions are not quantified as part of the AESC 2021 study.

[63] U.S. Environmental Protection Agency's (EPA) MOVES model is one example of such a resource. https://www.epa.gov/moves.

4. COMMON ELECTRIC ASSUMPTIONS

The following section contains input assumptions which are common to the calculations of avoided electric energy, avoided electric capacity, and avoided RPS compliance.

One of the main tasks of the AESC 2021 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. 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 Chapter 0 and Chapter 3, respectively) modeling assumptions in AESC 2021 differ from those used in AESC 2018 in terms of the following:

- Examination of different load trajectories under four counterfactual scenarios
- Lower projections for annual sales (not including impacts associated with building or transportation electrification)
- Inclusion of impacts of transportation electrification in all four counterfactual scenarios
- Updated assumptions on clean energy additions, including substantial updates to new long-term contracting requirements (e.g., for offshore wind and other renewables), modifications to online dates for certain clean energy projects, and updates of other renewable policies including RPS
- Updated assumptions for known and estimated unit retirements as well as unit additions
- Lower projections for compliance prices under RGGI

4.1. AESC 2021 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.[64] 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 (FCA) are held each year,

[64] See ISO New England's *2019 Annual Markets Report* for more information at https://www.iso-ne.com/static-assets/documents/2020/06/a6_2019_annual_markets_report.pdf.

three years in advance of a specified future operating period. ISO New England also manages other ancillary markets, including regulation and reserve markets.

AESC 2021 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
- 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 using the *EnCompass National Database*, created by Horizons Energy. Horizons Energy benchmarked its comprehensive dataset across the 21 North American Electric Reliability Corporation (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. Table 21 shows load and generation areas to be reported on in AESC 2021 and Table 22 details modeled load and generation areas. This is the same modeling topology as that used in AESC 2018. For AESC 2021, we use load-weighted averages to translate modeling zones into reporting zones. 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 23).[65] These weighting percentages are updated with 2019 nodal data that are similar, but not identical to, the weightings used in AESC 2018 (which was based on 2016 nodal data).

Table 21. Reporting zones in AESC 2021

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

Table 22. Modeled load zones in AESC 2021

EnCompass Region	ISO New England sub-area
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

[65] Pnode load factors for 2019 are available on the ISO New England website at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/nodal-load-wgts.

Table 23. Translation between EnCompass modeling zones (vertical) and AESC 2021 reporting zones (horizontal)

		ME	NH	RI	VT	All CT	SW CT	NE CT	All MA	SE MA	NE MA	WC MA
NE Maine Northeast	BHE	15%	-	-	-	-	-	-	-	-	-	-
NE Maine West Central	ME	50%	-	-	-	-	-	-	-	-	-	-
NE Maine Southeast	SME	35%	-	-	-	-	-	-	-	-	-	-
NE New Hampshire	NH	-	82%	-	3%	-	-	-	-	-	-	-
NE Vermont	VT	-	16%	-	91%	-	-	-	-	-	-	-
NE Boston	Boston	-	-	-	-	-	-	-	46%	-	100%	1%
NE Mass. Central	CMA/ NEMA	-	3%	-	-	-	-	-	13%	-	-	46%
NE Mass. West	WMA	-	-	-	6%	1%	-	2%	15%	-	-	53%
NE Mass. Southeast	SEMA	-	-	10%	-	-	-	-	20%	77%	-	-
NE Rhode Island	RI	-	-	90%	-	-	-	-	6%	23%	-	-
NE Connecticut Northeast	CT	-	-	-	-	50%	-	98%	-	-	-	-
NE Connecticut Southwest	SWCT	-	-	-	-	32%	66%	-	-	-	-	-
NE Norwalk Stamford	NOR	-	-	-	-	17%	34%	-	-	-	-	-

Notes: Totals may not add due to rounding.

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.[66]

[66] 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 2021 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 AESC 2021 study uses a spreadsheet model to develop FCM auction prices for power years from June 2021 onwards. We coordinate the major input assumptions regarding the forecasts of peak load and available capacity in each power year 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 12 through FCA 15, 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 FCA 15. See Chapter 5: *Avoided Capacity Costs* for more detail on the methodology.

Modeled market rules

The EnCompass model approximates the market rules 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 O&M 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

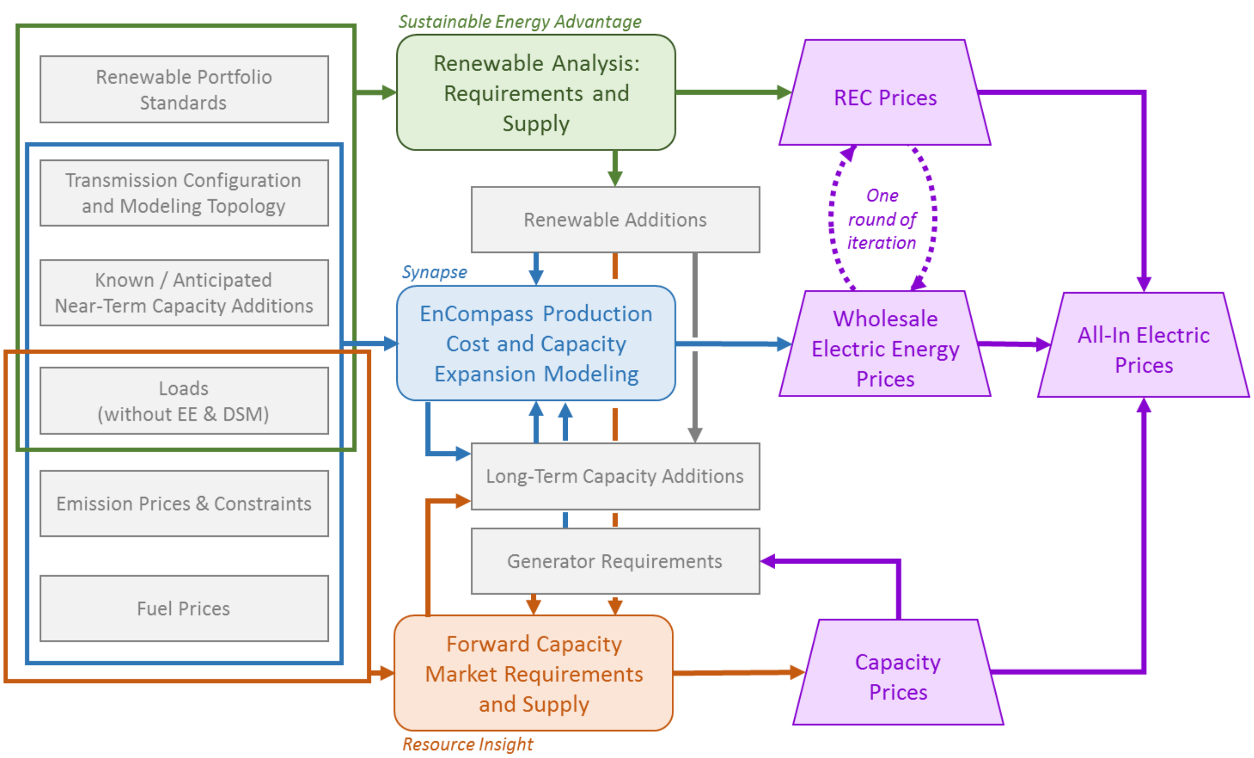
Installed-capacity requirements for the EnCompass model include reserve requirements established by ISO New England on an annual basis. Current estimates of the reserve-margin and installed-capacity requirement (with and without the Hydro Quebec installed-capacity credits) are described in Chapter 5: *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.

Figure 12 highlights the interactions between the models used in AESC 2021.

Figure 12. AESC 2021 modeling schematic



Energy Security Initiative

ISO New England proposed a package of new day-ahead reserve products through its *Energy Security Improvements* (ESI) proposal to address concerns over fuel security in the winter. The proposal utilized call options on energy, which have not been used in other regional transmission organizations, to address what the ISO describes as a "misaligned incentives problem" under the current market rules. The Federal Energy Regulatory Commission (FERC) rejected ISO New England's proposal on October 30, 2020 due to concerns about the impact it would have on energy security as measured by metrics such as reserve shortage hours and loss of load, as well as the costs the proposal would impose on consumers.[67] FERC was particularly concerned that ESI would produce reserves on a one-day-ahead timeframe that would not provide resource owners enough time to procure firm fuel supplies. The New England Power Pool (NEPOOL) offered an alternative version of ESI that adjusted some of the reserve products the ISO would procure and reduced the total quantity of reserve product purchases, particularly in the non-winter months. The NEPOOL alternative was projected to be less costly to consumers but was also rejected by FERC because it did not address FERC's concerns with the timing of the reserve procurement and the expected limited impact on reserve shortage hours.[68] ISO New England is reviewing FERC's decision and will be discussing next steps with stakeholders. As of November 2020, timing for next steps was uncertain. We recommend that any impacts attributed to ESI be incorporated in a future AESC study or study update.

Modeling timescale

In EnCompass, REMO, and the FCM Model, we explicitly model 15 years from 2021 through 2035. In order to develop 30-year levelized avoided costs, AESC 2021 continues the trajectory of each avoided cost component through 2050.[69]

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.[70] We run EnCompass at the resolution of a typical week. This means that EnCompass represents each year from 2021 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 days," and each day of which is represented by a 24-hour chronological dispatch period.

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[67] *ISO New England Inc.*, 173 FERC ¶ 61,106 (2020).

[68] 173 FERC ¶ 61,106.

[69] In all cases, this involves extrapolating values through 2055. See Appendix A: *Usage Instructions* for the methodology used.

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

- 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 8,760-hour resolution for each year between 2021 and 2035.

- Hourly 8,760 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).[71]

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 effect of uncleared capacity for demand response will vary with the number days each summer for which peak load is reduced and the number of years for which the load reduction continues (see Appendix J: for more information).

- 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.[72]

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

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

[72] 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.

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, and with the same computations for demand response.
- 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.

Model calibration

Because one of the main outputs of the AESC 2021 study is the estimation of avoided electric energy costs, it is essential that modeling outputs for wholesale energy prices are in line with actual, recent historical wholesale energy prices. In this analysis, we compare the model's projected regional hourly price forecasts to 2019 prices in the ISO New England's "SMD" dataset.[73] See Section 6.2: *Benchmarking the EnCompass energy model* for more information on the results of the model calibration for energy costs.

Note that because several of the AESC counterfactuals project futures that lack any incremental energy efficiency installed beyond 2020, prices in future years are likely to substantially diverge from recent historical prices.

4.2. Modeling counterfactuals

The *AESC 2021 User Interface* (a separate Excel workbook) includes hourly values in addition to the four traditional energy costing periods (summer on-peak, summer off-peak, winter on-peak, and winter off-peak).[74] These 8,760 avoided cost values may help refine the quantification of traditional DSM programs that have relied upon avoided cost values from previous AESC studies.

New to the AESC 2021 study is the development of four different counterfactual scenarios for our analysis. Table 24 details the DSM components modeled in each of the counterfactuals. Generally speaking, each of the avoided cost streams is the "but for" costs attributed to the counterfactual scenario, so those specific DSM components are excluded in the specified scenario. For purposes of simplification and comparison, Counterfactual #1 is the counterfactual used for the discussion of many

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[73] "SMD" is a legacy acronym referring to "Standard Market Design." Currently, the primary application of this term is in the naming of this dataset. The SMD dataset containing hourly data for 2019 can be found at on the ISO New England website at https://www.iso-ne.com/static-assets/documents/2019/02/2019_smd_hourly.xlsx.

[74] Appendix B: *Detailed Electric Outputs* contains the cost streams associated with the four costing periods consistent with previous AESC studies.

high-level findings and comparisons with previous AESC study results throughout this report. The following two sections on system demand and renewable energy policies describe the assumptions used for each of the DSM components.

Table 24. Modeled counterfactual scenarios in AESC 2021

DSM component included?	**Counterfactual #1** *AESC for EE, ADM and building electrification*	**Counterfactual #2** *AESC for building electrification only*	**Counterfactual #3** *AESC for EE only*	**Counterfactual #4** *AESC for EE and ADM only*
Energy Efficiency (EE)	*No*	Yes	*No*	*No*
Active Demand Management (ADM)	*No*	Yes	Yes	*No*
Building electrification	*No*	*No*	Yes	Yes
Transportation electrification	Yes	Yes	Yes	Yes
Distributed generation	Yes	Yes	Yes	Yes

Notes: A "Yes" indicates that the relevant DSM component is included (e.g., modeled) within that counterfactual. A "No" indicates that the DSM component is not incorporated into the modeling in 2021 or any future year. A "No" only removes the programmatic resources associated with each DSM component (e.g., energy efficiency associated with codes and standards is modeled in all scenarios, as is storage or demand response owned or funded by entities other than program administrators).

4.3. New England system demand

Forecasts of annual peak demand and energy used in each of the AESC 2021 models are in large part based on the 50/50 values published by ISO New England in the 2020 *Forecast Report of Capacity, Energy, Loads and Transmission* (CELT) study.[75] However, our forecast includes modifications and enhancements to this forecast. Specifically, our load forecast covers the following components:

- Econometric forecast: This is a projection of energy consumption (in MWh) and peak demand (in MW) related to traditional electric end-uses, based on data provided in ISO New England's 2020 CELT forecast. It also includes historical energy efficiency installed through 2020, but does not include any energy efficiency installed in 2021 or later years. It also does not include impacts from any of the categories discussed below.

- Energy efficiency: This is a projection of energy efficiency measures for 2021 and later years, for all New England states based on data provided in ISO New England's 2020

[75] 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 high and low ranges of estimates for demand.

CELT forecast. It is used in counterfactuals that estimate avoided costs for measures *other than* energy efficiency.

- Building electrification: This is a projection of the impacts from residential heat pumps, based on data provided in ISO New England's 2020 CELT forecast. It is used in counterfactuals that estimate avoided costs for measures *other than* building electrification.

- Active demand management: This is a projection of the impacts from demand response and behind-the-meter (BTM) energy storage, based on data in ISO New England's FCM and program data reported by states and utilities. It is used in counterfactuals that estimate avoided costs for measures *other than* active demand management.

- Transportation electrification: This is a projection of the impacts from light-, medium-, and heavy-duty electric vehicles, based on data from Bloomberg New Energy Finance's (BNEF) Electric Vehicle Outlook 2020. It is used in all counterfactuals.

- Distributed generation: This is a projection of the impacts from distributed solar, based on the implied quantities resulting from state renewable policy. It is used in all counterfactuals. See Section 4.4: *Renewable energy* for more information on this topic.

Econometric forecast

The following sections focus on the "econometric" forecast for electricity demand. Generally speaking, this forecast includes futures impacts of measures (such as energy efficiency) installed in past years, as well as future impacts of "traditional" electric end-uses (e.g., not transportation electrification or building electrification).

Annual energy demand

In May 2020, ISO New England released its newest electricity demand forecast, CELT 2020.[76] As in the CELT forecasts before it, in CELT 2020 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 with data from 1990 through 2019.

To calculate the econometric component of electricity demand in AESC 2021 (e.g., the component of electricity demand driven by factors like population, gross domestic product, and weather—rather than energy efficiency or electrification).[77] We do not rely on the specific MWh demand quantities articulated

[76] Further information about the CELT forecast can be found at ISO New England's website at https://www.iso-ne.com/system-planning/system-plans-studies/celt, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/ and https://www.iso-ne.com/static-assets/documents/2020/04/modeling_procedure_2020.pdf.

[77] Note that ISO New England's econometric forecast can be impacted by the effects of federal energy efficiency standards and other non-programmatic energy efficiency.

in the 2020 CELT study, as these quantities start with a projected level of 2020 demand that will likely exceed actual 2020 demand in part due to the COVID-19 pandemic.

Instead, we examined monthly actual versus projected system demand through July 2020 (see Figure 13).[78] From January through July, actual regionwide system demand was, on average, 7 percent lower than system demand as projected in CELT 2020. These monthly differences range from a high of 12 percent lower than projected in May to a low of 3 percent *greater* than projected in July. These monthly differences are not solely attributable to the COVID-19 pandemic; instead, differences in projections and observed system demand in January, February, and (at least part of) March are likely mostly due to differences in projected versus actual weather.[79]

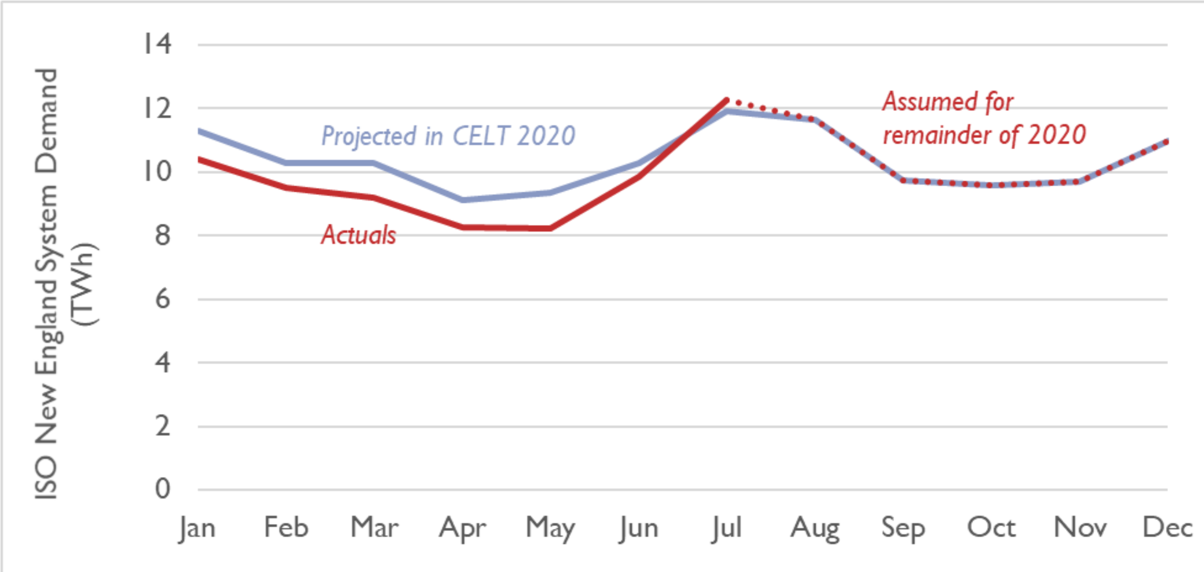
Assuming that system demand returns to projected levels in August through December 2020 (as the June and July data points suggest it may) we find that, for the year as a whole, actual 2020 system demand would be 4 percent lower than projected by CELT 2020. We apply this scaling factor to ISO New England's projection of 2020 Gross Demand (less electrification and incremental energy efficiency) as it is defined in ISO New England's 2020 CELT study to determine a new, adjusted starting point for the AESC 2021 forecast. To create system load values for 2021 through 2029, we apply the compound annual growth rate (CAGR) for 2020 through 2029, as estimated for each of the 13 modeling regions in CELT 2020. To calculate system demands for 2030 through 2035, we apply the CAGR calculated for each region in CELT 2020 for the last five years (2025 through 2029) and compared to AESC 2018 (see Figure 14).[80]

[78] Monthly actual system demand for 2020 is available on ISO New England's website at https://www.iso-ne.com/static-assets/documents/2020/02/2020_smd_monthly.xlsx.

[79] Note that this comparative analysis does not distinguish between shifts in system demand (e.g., commercial versus residential air conditioning).

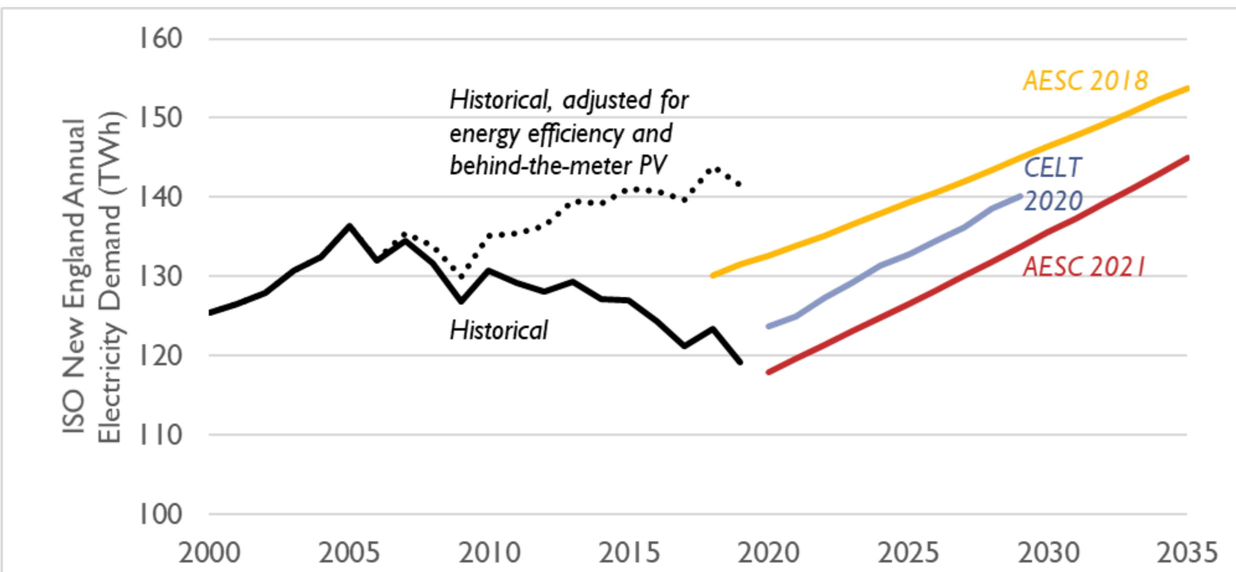
[80] Note that the regionwide CAGR calculated for gross demand in each of the CELT forecasts from CELT 2015 to CELT 2019 have ranged from 0.9 percent to 1.1 percent.

Figure 13. Actual versus projected system demand for 2020, ISO New England



Notes: All trajectories are inclusive of the effects of energy efficiency, BTM solar, and electrification.

Figure 14. Historical and projected annual energy forecasts for all of ISO New England



Notes: In both the "CELT 2020" and "AESC 2021" trajectories, all data points are decreased to reflect the energy efficiency installed in 2020 (see following section on "Programmatic Energy Efficiency"). No other impacts from energy efficiency, active demand management, building electrification, transportation electrification, or distributed solar are included.

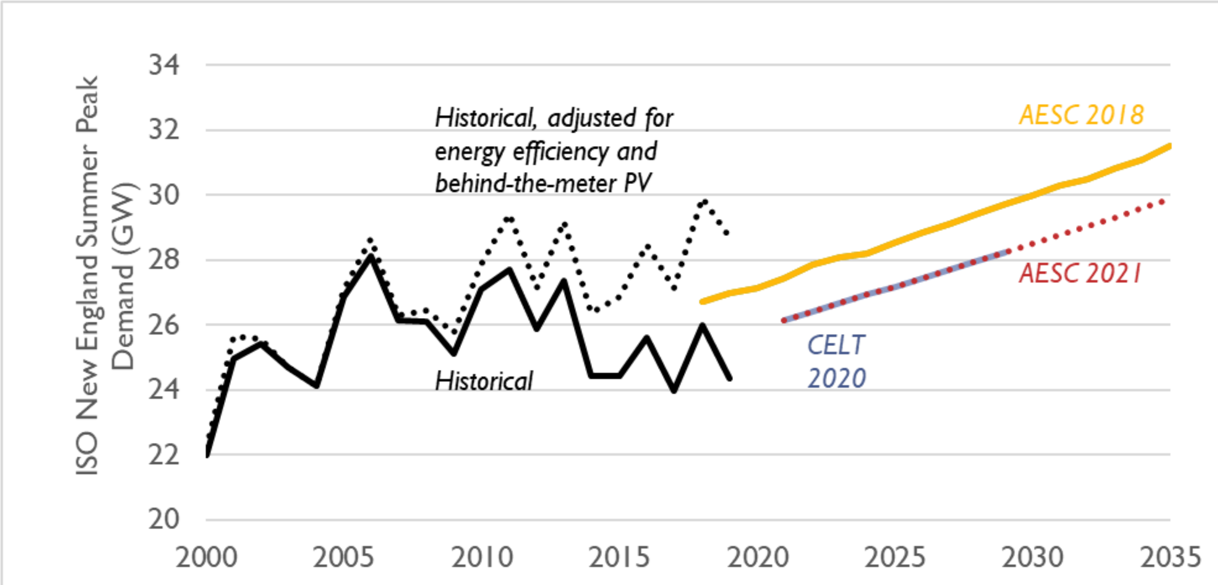
In order to develop hourly system energy demand, we apply hourly load shapes developed for each load zone published by ISO New England in the 2020 CELT study.[81] Note that while it is possible that load shapes may change over time, the scale and shape of these changes are uncertain. As a result, we rely on ISO New England's load shapes for purposes of simplification. Load shapes for other components of system load (e.g., energy efficiency, transportation electrification) are discussed in the *Other System Demand Components* section, below.

Peak demand forecasts and capacity requirements

To calculate peak demand, we compare projected summer peak demand from CELT 2020 with actual historical data. Per CELT 2020, the projected 50/50 net summer peak for ISO New England in 2020 (inclusive of impacts from energy efficiency, distributed solar, building electrification, and transportation electrification) was 25,125 MW. Through July 2020, the actual observed system peak was 25,054 MW (about 0.3 percent lower than projected). Based on the available data, it appears as though the COVID-19 pandemic has not had a substantial impact on summer peak in New England. As a result, we rely on the gross summer peak as specified in CELT 2020 (see Figure 15).

[81] Hourly load shapes developed by ISO New England for the CELT 2020 forecast can be found on the ISO New England website at https://www.iso-ne.com/static-assets/documents/2020/04/hourly_sa_fcst_eei2020.txt.

Figure 15. Historical and projected summer peak demand forecasts for ISO New England

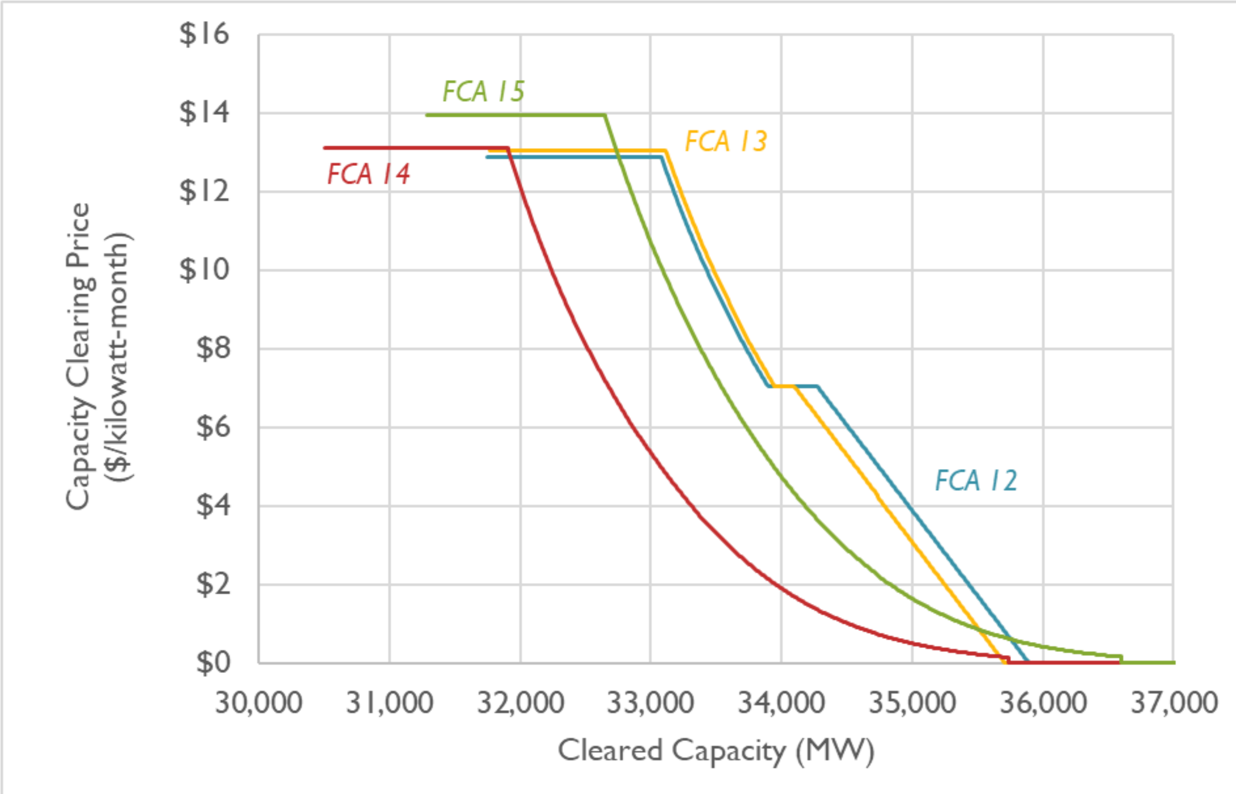


Note: The "AESC 2021" projection shown in this chart differs from the peak demand created in our EnCompass modeling as this value is calculated based on annual data available in ISO New England's CELT forecast, whereas the modeled values are calculated dynamically based on hourly, regional load shapes. For Counterfactual #1, this illustrative projection matches the modeled projection within +/-5 percent in all years.

The 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 three years after that. For example, the peak forecast for the summer of 2021 (released in May 2020) will be used to set the installed-capacity requirement for FCA 15 (held in February 2021) which sets the capacity obligations and prices for the period June 2024 to May 2025.

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 16 shows the demand curve used in FCAs 12 through 15. ISO New England has transitioned from demand curves that partly followed the marginal reliability index (MRI) and were partially linear, with a flat part in between, to all-MRI curves in FCA 14 and 15.

Figure 16. Sloped demand curves, FCAs 11 to 15



Other system demand components

The following sections describe our other modifications to system demand. Some of these components are incorporated in all AESC 2021 counterfactual scenarios, while other components may only be used in a single counterfactual.

Programmatic energy efficiency

Since 2008, ISO New England has sought to compensate for these "embedded energy efficiency" effects by explicitly accounting for "passive demand resources" (PDR).[82] Thus, programmatic energy efficiency is excluded from the main ISO New England econometric forecasts, producing a "gross" forecast for annual energy and peak demand that is higher than it would be without the impact of PDRs. Starting in 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 (PV). ISO New England then subtracts the forecasted quantities of PDRs and distributed PV from its gross forecast to estimate a "net" forecast, a lower number that reflects the actual estimated demand for each modeled year.

[82] Prior to 2008, ISO New England's forecast implicitly contained some level of reductions from efficiency programs because the programs were in effect during the historical period.

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. ISO New England estimates future energy efficiency impacts first based on levels of capacity that have cleared in the FCM, and then on future estimated levels of resource addition and attrition. Like other components of the 2020 CELT forecast, this forecast contains estimates of energy efficiency through 2029.

For an energy efficiency trajectory in AESC 2021, we rely on a modified version of the energy efficiency forecast described in CELT 2020. [83] This modified forecast includes three major differences relative to CELT 2020:

- First, this forecast removes the use of ISO New England's production cost escalator, which causes costs-per-MWh of energy efficiency to be roughly 10 percent larger in 2029 than in 2021. The Study Group requested this escalator be removed in order to develop a forecast that is more consistent with the program administrators' internal energy efficiency plans.
- Second, this forecast assumes that all energy efficiency budgets assumed by ISO New England for 2029 remain constant through 2035. This forecast also assumes that all end-use shares for energy efficiency measures (i.e., how much of a state's energy efficiency budget is dedicated to HVAC, or lighting, or other measures) remains constant from 2029 through 2035.
- Third, this forecast utilizes an energy efficiency forecast for Vermont provided by Vermont Department of Public Service, rather than the ISO New England forecast for energy efficiency in Vermont developed in the above steps.

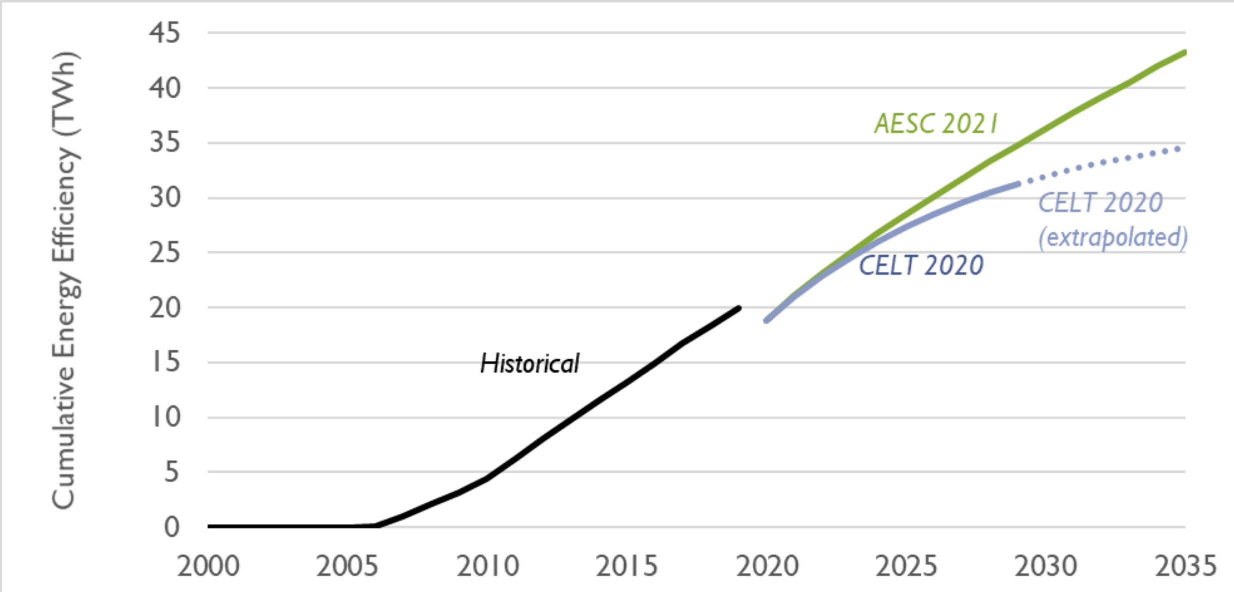
Figure 17 illustrates the difference in this modified forecast relative to the energy efficiency forecast provided in CELT 2020.

Generally speaking, past AESC studies have not considered scenarios that include forward-going levels of energy efficiency. This is the case in AESC 2021 for Counterfactual #1 and Counterfactual #3.[84] However, Counterfactual #2 requires a projection of energy efficiency.

[83] Another alternative considered by the Synapse Team would have extended recent historical levels of incremental savings through 2035. This forecast produced cumulative savings that were 15–20 percent higher than the CELT 2020 forecast through 2025, with greater differences in savings in later years.

[84] Note that, as in AESC 2018 but unlike AESC 2015, we do not decrease demand in future years to reflect energy efficiency for which program administrators are financially committed, but have not yet 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 2021 from evaluating these resources' cost-effectiveness because of double-counting.

Figure 17. Historical and projected cumulative regionwide energy efficiency impacts used in Counterfactual #2



For Counterfactual #2, Synapse uses the same load shape for energy efficiency that is used for the econometric component of the energy forecast. This will effectively reduce the econometric component in every hour by the fraction of modeled energy efficiency (in MWh) relative to the system demand. While in reality, different energy efficiency measures have different load profiles, this simplified approach is meant to approximate the implementation of a portfolio of energy efficiency measures. Peak impacts of energy efficiency, and energy efficiency's contribution to the capacity requirement, will be determined by estimating the peak hour for energy efficiency in each year, based on the annual regionwide energy efficiency amount and annual system demand impact.

Active demand management

For the purposes of AESC 2021, active demand management includes both demand response measures as well as BTM energy storage measures. We modeled both resources as supply-side resources in the EnCompass model. Impacts of both types of resources are applied to peak demand calculations in the relevant counterfactuals.

This component is included in the modeling of Counterfactual #2 and Counterfactual #3, but not Counterfactual #1.

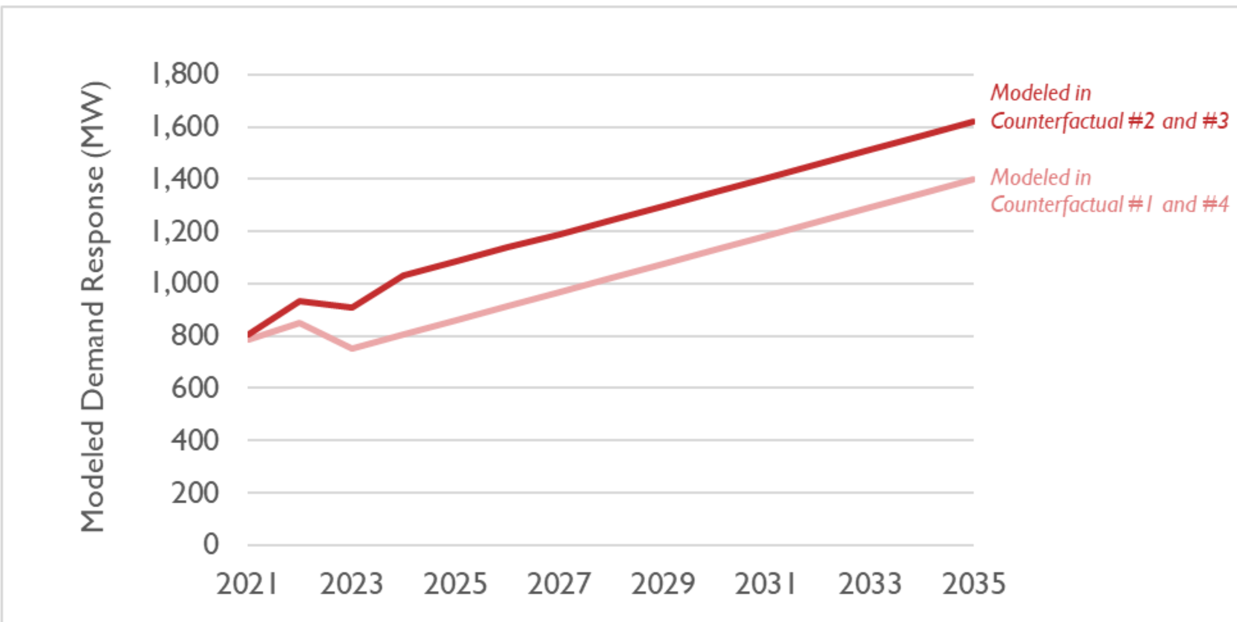
<u>Demand Response</u>

Demand response participates in ISO New England's FCM and serves as a peak demand resource. Demand response participation in the FCM has grown steadily for several years. To forecast demand response impacts in future years, we have extended the trend observed between capacity compliance periods between the summers of 2019 and 2023 linearly through 2035 (see Figure 18). In FCA 14, 592 MW of demand response capacity cleared the market and received a capacity supply obligation. We assume that all demand response that has cleared in the FCM so far is non-programmatic and is modeled in all counterfactuals.

In addition, we assume that under the current draft planning numbers for demand response Massachusetts is planning to install roughly 160 MW of measures capable of demand response in 2020 and perhaps double that quantity by 2024. This is the programmatic quantity assumed to be modeled in Counterfactual #2 and Counterfactual #3.

Based on recent historical behavior in the energy market, we assume that 10 percent of the entire demand response resource dispatches when prices are greater than $30 per MWh (in 2019 dollars) while 90 percent of this resource dispatches when prices exceed $900 per MWh (e.g., a stand-in for rare, very high price events).

Figure 18. Demand response forecast for New England



Energy Storage

There is currently no regional projection of BTM storage for New England. Furthermore, there is no data on existing BTM installations publicly available, although this data may be available to individual utilities. To establish a baseline of existing and projected BTM storage installation in New England, we have assembled data and projections from policy mandates and incentives for BTM storage for every state and New England. We then aggregated these projections to forecast total BTM storage capacity through 2035.

- Connecticut: In Connecticut, Eversource administers the Connected Solutions program which provides residential customers incentives for supplying their own batteries.[85] Under this program, customers can receive incentive payments of up to $225 per average kW used from their demand response resources over a three-hour period in certain seasons. The program supports only three battery vendors, including Sonnen, Generac, and Tesla.

- Maine: In December 2019, the Maine PUC was tasked with considering "bring your own device" (BYOD) programs for BTM energy storage in the state.[86] While there is no official BTM storage target or policy incentive, movement on this topic is forthcoming.

- Massachusetts: The first major incentive for storage is an adder as part of the Solar Massachusetts Renewable Target (SMART) program. As of February 2021, this program had approved about 40 MW of BTM storage in Massachusetts.[87] In April 2020, the state doubled the program target for solar from 16 GW to 32 GW. Though there is no specific target for BTM storage in this expansion; for the purposes of AESC 2021, we assume the capacity for BTM is doubled to reflect this update.

  Second, as in Connecticut, Eversource and National Grid deploy the Connected Solutions program through Mass Save, which provides residential customers an incentive for supplying their own batteries.[88, 89]

  Third, there are other programmatic BTM storage initiatives currently ongoing in Massachusetts, including the Daily Dispatch program and the Cape and Vineyard Electrification Offering (CVEO) program.[90] However, data on expected projections of BTM storage was not available at the time of our analysis.

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85 Eversource. Accessed March 10,2021. *Program Materials for Connected Solutions for Commercial/Industrial Customers*. Available at https://www.eversource.com/content/docs/default-source/save-money-energy/program-materials-demand-response.pdf?sfvrsn=695bd362_0.

86 Maine 127th Legislature. December 2019. "Commissions to Study the Economic, Environmental and Energy Benefits of Energy Storage to the Maine Electricity Industry." Available at: https://legislature.maine.gov/doc/3710.

87 Massachusetts Department of Energy Resources (DOER). "SMART Qualified Units." Accessed February 5, 2021. Available at: https://www.mass.gov/doc/smart-qualified-units-0.

88 MassSave. Last Accessed March 10,2021. "Use Your Battery Storage Device to Make the Grid More Sustainable." *Massave.com.* Available at https://www.masssave.com/saving/residential-rebates/connectedsolutions-batteries.

89 Members of the Study Group provided information on recently installed measures in Massachusetts' Connected Solutions program. For purposes of simplification and to avoid double-counting, we assume that all measures in this program are either also participating as demand response in the FCM or in the SMART program and are already accounted for in either one of the two projections.

Mass Save. February 11, 2020. *Energy Efficiency Program Administrators Quarterly Report*. Available at https://ma-eeac.org/wp-content/uploads/Quarterly-Report-of-the-PAs-2019-Q4-2-11-20-1.pdf.

Mass Save. August 12, 2020. *Massachusetts Energy Efficiency Program Administrators Quarterly Report.* Available at https://ma-eeac.org/wp-content/uploads/Quarterly-Report-of-the-PAs-2020-Q2-Final.pdf.

90 Winter, D. March 16, 2016. *D.P.U. 20-33 – Fitchburg Gas and Electric Company d/b/a Until (Electric Division)*. Keegan Werlin LLP prepared for Department of Public Utilities. Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/11942570.

Finally, the newly launched Clean Peak Standard (CPS) may also serve as an incentive for BTM storage in the state. The CPS went into effect in June 2020. Qualified resources under the CPS include new renewable resources that also meet eligibility under Massachusetts' Class I and Class II RPS program.[91] Existing renewable resources in both programs are eligible, so long as these resources are paired with a new energy storage system. Furthermore, both standalone energy storage systems and demand response resources are eligible to meet the CPS. Modeling published by Massachusetts Department of Energy Resources describes the estimated benefits under the CPS, which are projected to reach over 120,000 metric tons by 2030.[92] Assuming that all of these benefits are provided by BTM storage, and that storage is able to provide a benefit of 60 metric tons per MW, this implies a 2030 capacity of about 2.0 GW.[93] This is substantially larger than the Commonwealth's current storage target of 500 MW in 2025.[94]

Based on recommendations from the AESC Study Group, we assume an exogenous 500 MW of storage in Massachusetts in 2025 and all later years.[95] Of this quantity, we assume that 70 percent is funded through the current energy efficiency programs, due to the size of the incentives offered in that program versus others (e.g., SMART, CPS). This 350 MW is the programmatic portion of storage assumed in Massachusetts. The remaining 150 MW non-programmatic portion is met through other programs, including SMART and CPS.

- <u>New Hampshire</u>: The New Hampshire Public Utilities Commission (PUC) is currently examining whether and how BTM storage can or should be incentivized. In January 2019, the NH PUC approved a BTM pilot project for Liberty Utilities' customers. Liberty partnered with Tesla to install 500 Tesla Powerwall batteries and 500 other private company batteries (totaling 1,000 BTM batteries) to be used for demand response.[96]

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[91] Massachusetts Department of Energy Resources. October 26, 2020. *Clean Peak Energy Resource Eligibility Guide.* Available at https://www.mass.gov/doc/clean-peak-resource-eligibility-guidelines/download.

[92] Massachusetts Department of Energy Resources. August 7, 2019. *The Clean Peak Energy Standard.* Available at https://www.mass.gov/doc/drafts-cps-reg-summary-presentation/download . Slide 39.

[93] Per members of the Study Group, this metric tons per MW value is the avoided emissions value that has been applied for use in discussions regarding CPS.

State of Charge. 2017. *Massachusetts Energy Storage Initiative Study.* Prepared for Massachusetts Department of Energy Resources. Available at https://www.mass.gov/files/2017-07/state-of-charge-report.pdf. P. 95

[94] Massachusetts' energy storage goal is 1,000 MWh of storage by 2025 Per data available from *the* SMART program, the average duration of storage installed to date is 2 hours, which yields a storage target of 500 MW.

Massachusetts Department of Energy Resources. Last accessed March 11, 2021. "ESI Goals & Storage Target." *Massgov.com*. Available at https://www.mass.gov/info-details/esi-goals-storage-target.

[95] We note that the model is "allowed" to build more storage if it is economic to do so in any of the counterfactuals, states, or years. See Section 4.5: *Anticipated non-renewable resource additions and retirements* for more information on the assumptions used for this endogenous storage resource.

[96] Gheorghiu, Iulia. 2019. "Designing Liberty Utilities' New Hampshire residential storage program." *Green Tech Media (GTM)*. Available at: https://www.utilitydive.com/news/designing-liberty-utilities-new-hampshire-residential-storage-program/548940/

This program will put an estimated 5 MW of BTM storage in New Hampshire.[97] The program estimates roughly 100 batteries, equivalent to 500 kW of battery storage, will become operational per year.[98]

- Rhode Island: As in Massachusetts and Connecticut, National Grid administers the Connected Solutions program which provides residential customers incentives for supplying their own batteries.[99]

- Vermont: The main service provider for the state of Vermont, Green Mountain Power (GMP), has partnered with Tesla to pilot a BTM storage program for the state. This program, coupled with a provision that allows customers to "bring your own device" (BYOD), has incentivized between 13 and 14 MW of BTM storage installed in the state in 2019.[100] The program has been expanded and is projected to add up to 5 MW per year for the next 15 years.

The storage forecast from 2019 through 2035 for the entire New England region is shown in Figure 19.

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[97] State of New Hampshire Public Utility Commission. Order No. 26,209. January 2019. Available at: https://www.clf.org/wp-content/uploads/2019/01/26-209.pdf

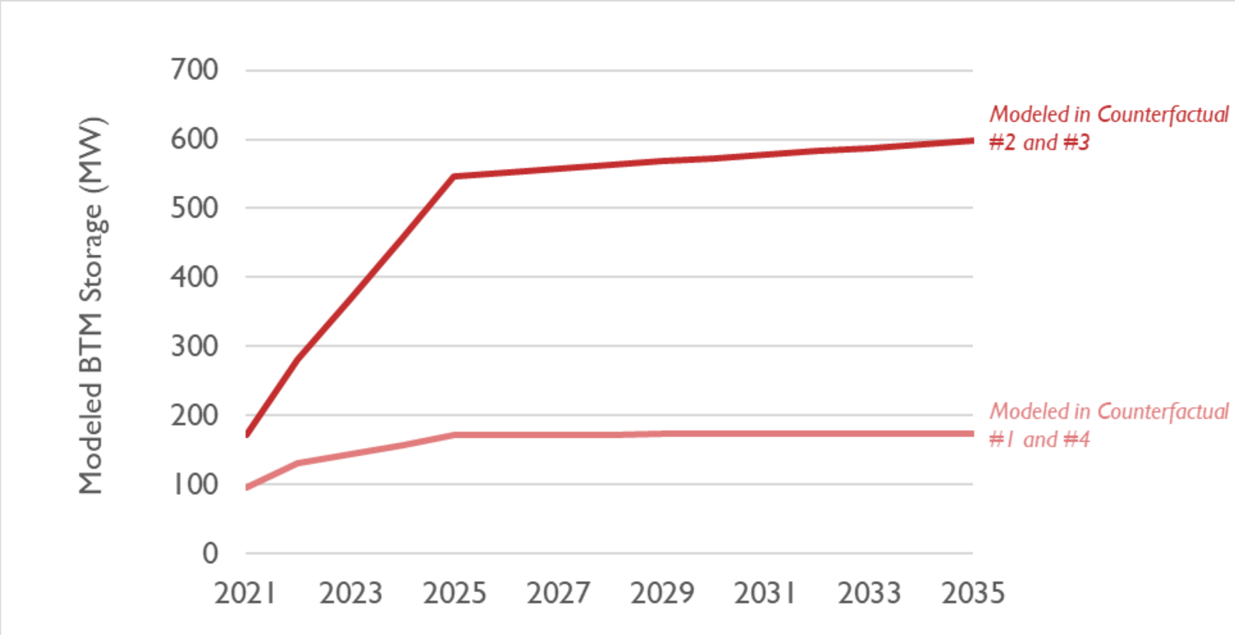
[98] Members of the Study Group provided information on recently installed measures in New Hampshire's C&I Active Demand Response Program. This includes 7.5 MW of existing capacity. However, demand response and BTM storage programs are not differentiated in this document. For purposes of simplification and to avoid double-counting, we assume that all measures in this program are accounted for in the demand response projection described in the section above (see Figure 18).

New Hampshire's Electric and Natural Gas Utilities. January 15, 2020. *New Hampshire Statewide Energy Efficiency Plan 2020 Update.* Prepared for NH Saves. Available at https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2020-01-15_EVERSOURCE_UPDATED_EE_PLAN.PDF.

[99] National Grid. Accessed August 27, 2020. "Use Your Battery Device to Make the Grid More Sustainable." National Grid website. Available at: https://www.nationalgridus.com/RI-Home/ConnectedSolutions/BatteryProgram.

[100] Gheorghiu, Iulia. 2020. "Green Mountain Power expands PYOD and Tesla battery programs as it targets fossil peakers." *Utility Dive.* Available at: https://www.utilitydive.com/news/green-mountain-power-to-roll-out-byod-and-tesla-battery-programs-as-it-targ/578573/.

Figure 19. BTM storage forecast for New England



Our modeling uses the same battery dispatch profile for all BTM storage in New England. Given the predominance of the CPS in this forecast, we assume that storage will dispatch according to the CPS seasonal peak periods: Winter (December 1 through February 28) 4 p.m. to 8 p.m., Spring (March 1 through May 14) 5 p.m. to 9 p.m., Summer (May 15 through September 14) 3 p.m. to 7 p.m. and Fall (September 15 through November 30) 4 p.m. to 8 p.m.[101] Under the CPS, systems may only get CPS credits for discharging within these daily hours of hours per day, so we assume each system is limited to discharging once per day (or 365 cycles per year).

Our BTM storage modeling assumes a round trip efficiency (RTE) of 85 percent for all storage systems as is consistent with field tests of battery storage performance.[102] We calculate MWh from capacity assuming a 2-hour duration.

Given the lack of data on BTM storage projections, it is challenging to determine what portion of the above programs might be deployed as part of an active demand management program managed by one of the AESC 2021 Sponsors, and what portion may be deployed regardless of actions taken by the AESC 2021 Sponsors. Table 25 describes what category each of the above programs appears to fall into. For the purposes of AESC 2021, we assume that only policies marked as "Programmatic" are programmatic; all other policies are modeled in all counterfactuals.

[101] Massachusetts Department of Energy Resources (DOER). August 7, 2019. *The Clean Peak Energy Standard.* Available at https://www.mass.gov/doc/drafts-cps-reg-summary-presentation/download. Slides 15 and 19.

[102] Deline, Chris, et al. July 2019. *Field-Aging Test Bed for Behind-the-Meter PV + Energy Storage*. National Renewable Energy Laboratory (NREL). Available at: https://www.nrel.gov/docs/fy19osti/74003.pdf.

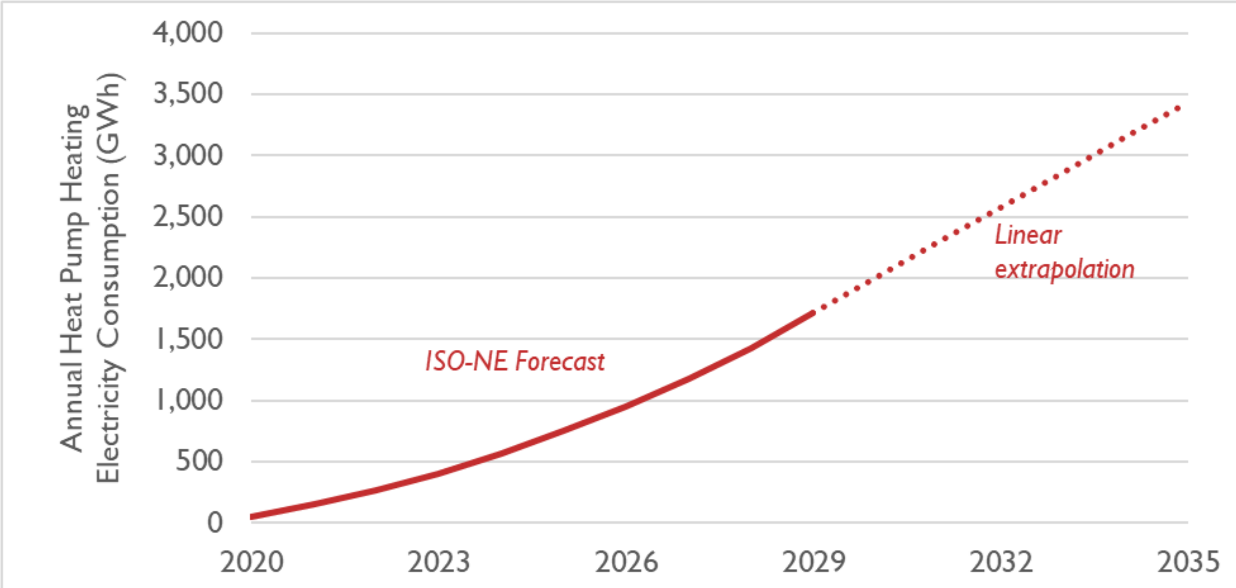
Table 25. Behind-the-meter storage categorization

State	Policy	Categorization
CT	Connected Solutions	**Programmatic**. Program entirely administered by Eversource; no data available
ME	*No known BTM storage policies*	-
MA	SMART program	**Unclear.** Project may overlap with other Massachusetts BTM storage policies. Measures assumed to be counted in the CPS program.
MA	Clean Peak Standard	**Unclear.** Project may overlap with other Massachusetts BTM storage policies.
MA	Connected Solutions	**Programmatic**. Program entirely administered by National Grid but assumed to be counted within the CPS program
MA	Daily Dispatch	**Programmatic**. Program entirely administered by PAs
MA	CVEO	**Programmatic**. Program entirely administered by CLC; no data available
NH	BTM Pilot (Liberty)	**Programmatic**. Program entirely administered by Liberty Utilities
RI	Connected Solutions	**Programmatic**. Program entirely administered by National Grid; no data available
VT	BTM Pilot (GMP)	**Programmatic**. Program entirely administered by Green Mountain Power

Building electrification

The adoption of electric air source heat pumps is projected to be a significant source of load growth over the study period, in certain counterfactuals. ISO New England developed a forecast of residential heat pump load as part of its CELT 2020 report to examine the winter electricity consumption of heat pumps (see Figure 20). ISO New England developed its forecast in collaboration with regional stakeholders who provided information about heat pump programs, incentives, and policy targets across the New England states. Heat pump adoption was modeled at the state level based on specific heat pump incentive programs.

Figure 20. Heat pump wholesale electricity impacts on heating for Counterfactual #3

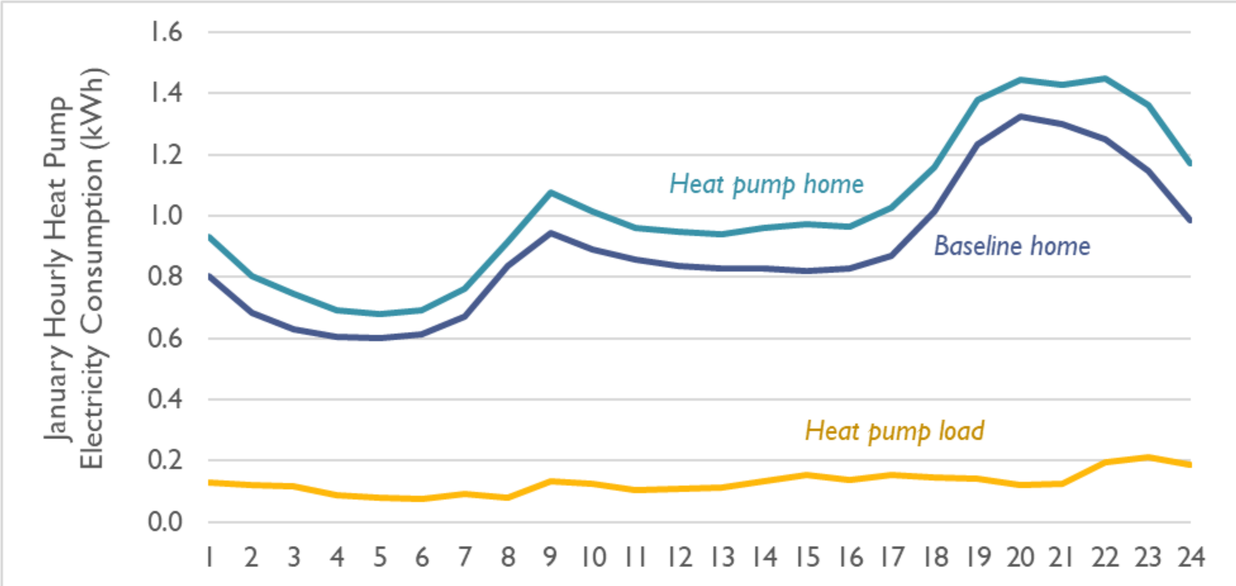


To develop hourly impacts, ISO New England combined its forecast for residential heat pump installations with advanced metering infrastructure load profile data for 18 residential heat pump installations in northeastern Massachusetts. ISO New England noted that this is a small sample size and that it may not be reflective of the entire region.[103] As more heat pumps are installed and additional studies become available, it is likely that this data will be refined. Currently, data availability for load profiles based on recent heat pump installations is limited.

ISO New England presented load shapes for homes with and without heat pumps in the advanced metering infrastructure data it acquired. This dataset included 33 homes with heat pumps and more than 400 homes without heat pumps. We calculated the hourly load profile of a heat pump by subtracting the baseline home load profile from a heat pump home load profile. The January load profiles (used for the winter season) are shown in Figure 21.

[103] ISO New England. 2019. "Draft 2020 Heating Electrification Forecast." *Load Forecast Committee.* Available at: https://www.iso-ne.com/committees/reliability/load-forecast/. Page 3.

Figure 21. Hourly heat pump load profiles for January



As in the CELT 2020 forecast, we assume that summer impacts of residential heat pump adoption will be small. As a result, we do not explicitly adjust summer loads. To inform this decision, we examined several different sources. First, a 2019 evaluation study of Connecticut heat pump installations reports the increased electricity loads resulting from heat pump installations in homes that previously lacked air conditioning, as well as the decreased electricity loads in homes that had central or window air conditioning prior to heat pumps.[104] The Connecticut study concludes (based on a weighted average of cooling systems prevalent in the state and average summer conditions) that heat pump installations summer savings are about 47 kWh per ton.

However, for several reasons, we believe that the expected long-term, New England-wide impact on cooling would be significantly smaller. First, some of the other New England states (particularly Vermont, New Hampshire, and Maine) would be expected to have lower penetrations of existing cooling systems and would therefore see more summer load growth and fewer cooling savings as a result of heat pump adoption. Second, the Connecticut study reports that heat pumps consume 26 percent as much electricity for cooling as they do for heating. Based on cooling and heating degree data for Massachusetts, we expect the long-term ratio of cooling to heating energy consumption to be significantly lower, as data for recent years suggests that the number of cooling degree days is only about 10 percent of the number of heating degree days.[105] This difference suggests that the heat pumps evaluated in the study may not have been sized to meet the full heating loads of the households, and

[104] DNV GL. June 20, 2019. *R1617 Connecticut Residential Ductless Heat Pumps Market Characterization Study – Final Report*. Available at: https://www.energizect.com/sites/default/files/R1617_CT%20Residential%20DHP%20Market%20Characterization%20Study_Final%20Report_6.20.19.pdf.

[105] Mass.gov. Accessed September 15, 2020. "Mass. Home Heating Profile Background." Available at: https://www.mass.gov/service-details/mass-home-heating-profile-background.

that incremental heat pump installations in these households (or future heat pumps installed without backup heating systems) would provide additional heat but not displace any additional cooling. Finally, heat pump energy savings in the summer may be included in the energy efficiency forecast, and thus not including additional savings here avoids potential double-counting. Additional data would improve the precision with which heat pump summer impacts could be quantified, but we believe these impacts are likely to be small and we have not quantified them in AESC 2021.

For the purposes of AESC 2021, all residential heat pump impacts are assumed to be programmatic.[106]

At this time, we do not have information to develop a forecast for other types of building electrification, including commercial or industrial heat pumps or variable refrigerant flow (VRF) systems, or other types of industrial electrification. The Study Group identified several studies that examine pilot programs aimed at these technology types in Massachusetts, Rhode Island, and Vermont; but projections that mirror the trajectories modeled for residential heat pumps, energy efficiency, and transportation electrification (for example) are currently unavailable.[107]

This component is included in the modeling of Counterfactual #1 and Counterfactual #3, but not Counterfactual #2. While some non-program heat pump adoption would be expected even in Counterfactual #2, we do not include any specific heat pump load forecast. ISO New England's general load forecast methodology includes a regression over historical load data that includes some amount of heat pump load. Thus, the general forecast implicitly includes a small amount of heat pump adoption, which is appropriate for a case in which no heat pump programs are implemented.

Transportation electrification

Over the study period of AESC 2021, vehicle electrification is projected to increase demand for electricity. In CELT 2020, ISO New England developed a forecast for electric vehicle (EV) electricity consumption as part of its CELT 2020 report. The CELT forecast uses a projection of the number of EVs sold in New England from AEO 2019. Among projections of EV adoption, AEO 2019 has one of the lowest forecasts, with EV sales projected to largely plateau after a limited increase in the 2020s. In place of this, Synapse has developed its own forecast to reflect the likelihood of continued growth in the EV market in the medium to long term. We use an EV sales forecast from Bloomberg New Energy Finance's (BNEF) *Electric Vehicle Outlook 2020*.[108] The Transportation and Climate Initiative's (TCI) reference case forecast was also considered, but ultimately not chosen due to its high short-term EV sales forecast, which is not

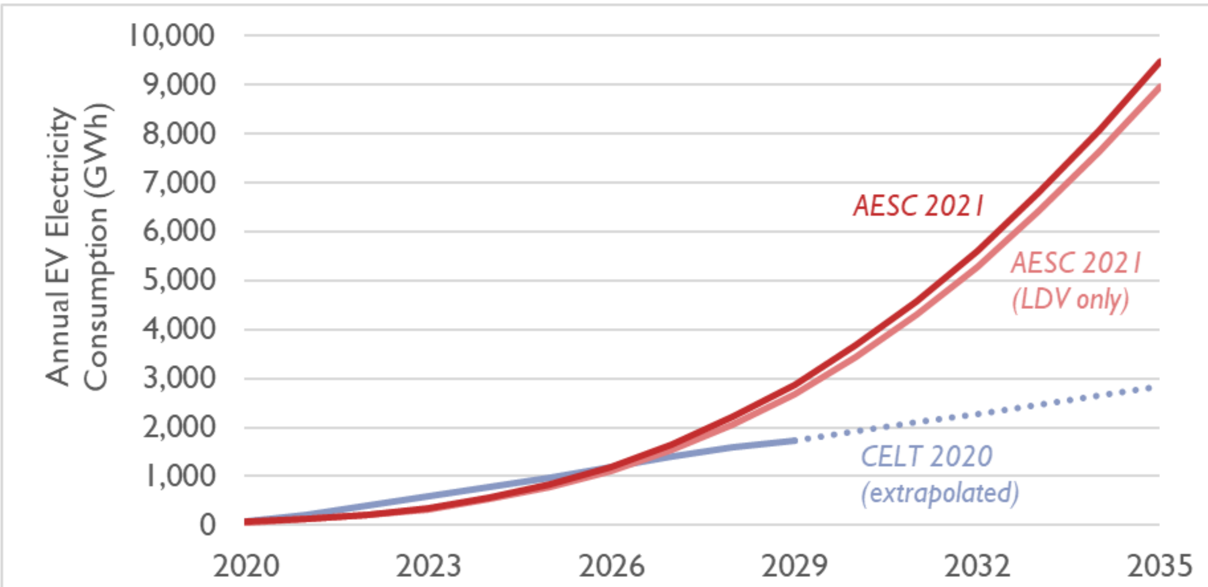
[106] Note that historically, a small amount of heat pump load growth has been implicitly projected in the CELT forecast through ISO New England's regression model.

[107] Synapse also examined deployment of commercial heat pumps in the 2020 edition of the AEO. According to underlying modeling data provided by EIA, commercial heat pumps currently make up less than 0.5 percent of New England's electricity demand; they are not projected to have any change in electricity consumption between 2018 and 2040, under the baseline conditions modeled in the 2020 AEO Reference case.

[108] Bloomberg New Energy Finance. 2020. *Electric Vehicle Outlook 2020*. Available at: https://about.bnef.com/electric-vehicle-outlook/.

in line with the most recent sales data.[109, 110, 111] Both the BNEF and TCI forecasts show similar levels of EV sales in the medium to long term. The Synapse forecast uses the Electric Vehicle Regional Emissions and Demand Impacts (EV-REDI) model to evaluate how long EVs remain on the road, how many miles EVs are driven, and how much electricity they consume.[112] One advantage of this methodology is that it eliminates the need to extrapolate the CELT forecast beyond 2029. We also use BNEF's global forecast for medium- and heavy-duty vehicle electrification to project electrification load associated with medium- and heavy-duty trucks (including buses). The CELT and Synapse load forecasts are shown in Figure 22 and peak demand impacts are shown in Figure 24.

Figure 22. Projected wholesale electricity consumption from EVs in ISO New England for all Counterfactuals



CELT 2020 also includes an hourly EV charging profile based on data acquired from the EV charging station company ChargePoint. This dataset includes a sample of charges located at both residential and commercial locations. ISO New England narrowed the dataset to include a greater fraction of residential charging, reflecting ISO New England's view that most EV charging occurs at homes. The CELT 2020 daily charging profiles are shown in Figure 23. These same EV load profiles are also used in the AESC 2021

109 Transportation and Climate Initiative. August 8, 2019. Reference Case Results Webinar. Available at: https://www.transportationandclimate.org/sites/default/files/20190808%20-%20TCI%20Webinar%20-%20Reference%20Case%20Results.pdf.

110 TCI is a regional collaboration of 12 states and the District of Columbia to improve clean transportation. Participating states include Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. States will choose individually whether to adopt the final proposed policy framework.

111 Note that we have used BNEF's forecast for passenger vehicles to forecast EV adoption for all light-duty vehicles, which includes both passenger vehicles and light commercial vehicles.

112 See Synapse's website at https://synapse-energy.com/tools/electric-vehicle-regional-emissions-and-demand-impacts-tool-ev-redi for more information on the EV-REDI model.

Study for both light-duty vehicles (LDV) and medium- and heavy-duty (MHD) vehicles.[113] The summer peak impact resulting from this EV adoption and load shape is shown in Figure 24.

Figure 23. Seasonal, hourly EV load profiles assumed by ISO New England in CELT 2020

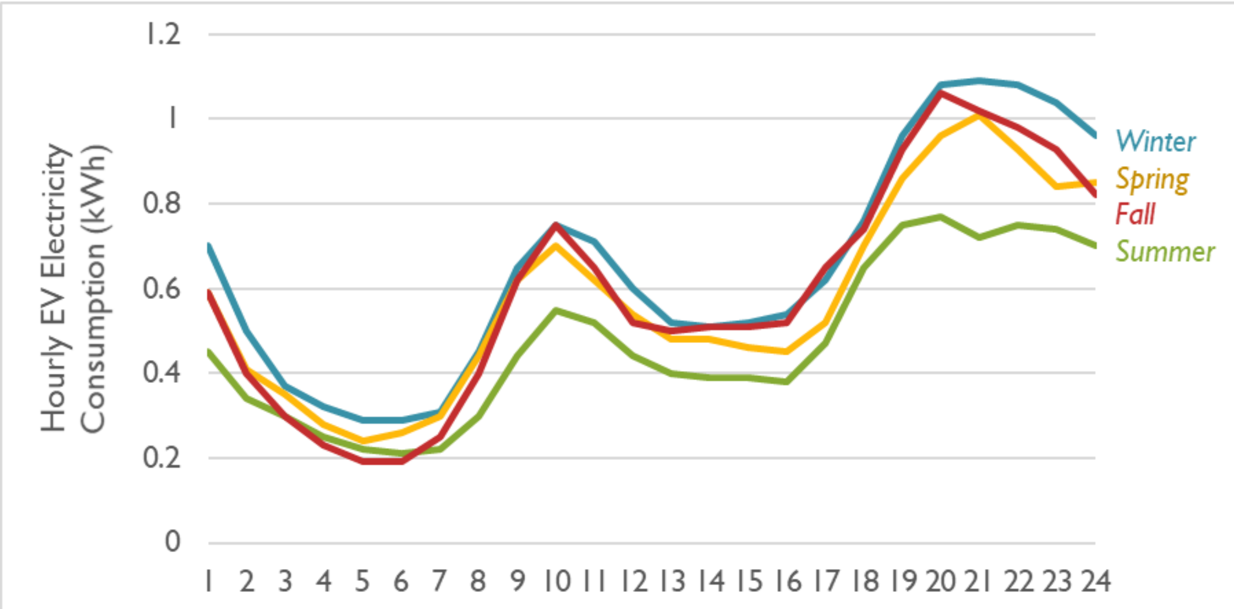
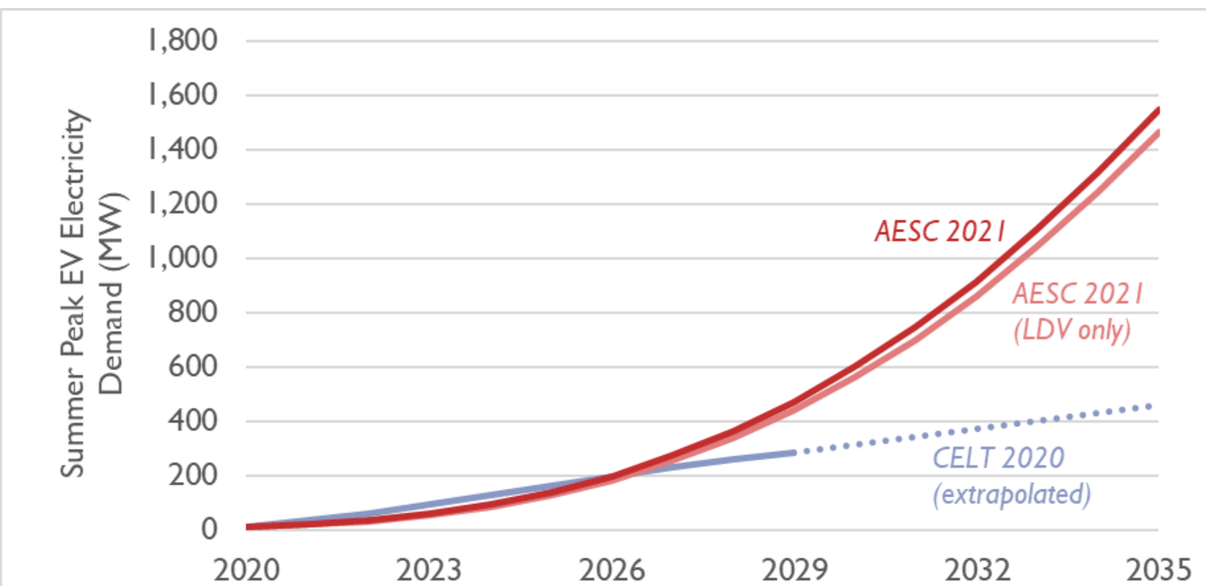


Figure 24. Summer EV wholesale peak demand impacts in ISO New England for all Counterfactuals



113 In reality, MHD vehicles are likely to differ in terms of daily charging profiles. However, given the diversity of MHD end-uses and the early stage of MHD EV adoption, there is little data available for a reasonable alternative. Finally, since most EV charging load modeled in AESC 2021 is associated with LDVs, it is unlikely that a different charging profile would substantially impact avoided costs.

Importantly, the ChargePoint data represents how EV charging has occurred historically. As EV load grows, there will be greater benefits associated with implementing managed charging programs and shifting more charging to off-peak periods. Limited managed charging programs are currently in place in New England. While the ChargePoint data is the best available source for historical charging patterns, it may misrepresent future charging behavior and may overstate peak impacts.

While the COVID-19 pandemic has affected the LDV market during 2020, we do not anticipate significant medium- or long-term impacts to the rate of EV adoption, in line with recent projections from other analyses. For example, an August 2020 EV projection published by Wood Mackenzie suggests that the impact of the COVID-19 pandemic on mid- to long-term EV adoption is likely to be limited.[114] As a result, we have not explicitly adjusted the EV load forecast to account for the COVID-19 pandemic. However, the EV sales forecast described above does have short-term sales projections in agreement with the most recent sales data that has been released during the pandemic.

This component is included in all counterfactuals and does not differentiate between programmatic or non-programmatic components.

Distributed generation

For the purposes of AESC 2021, "distributed generation" is assumed to include only distributed solar. Like active demand management, distributed generation is modeled as a supply-side resource in the EnCompass model. Impacts from distributed generation is applied to peak demand calculations in each counterfactual.

The 2020 CELT forecast contains a projection of BTM solar. This forecast applies material discount factors (35 to 50 percent) to post-policy distributed PV installation to reflect uncertainty associated with future policies and/or market conditions. This approach, which yields lower PV load reductions than what may be realistic, is appropriate for reliable planning and operation of the system. For the purpose of the AESC 2021 study, we used a distributed PV forecast that is more representative of expected solar installation under existing policies and future policies (if applicable) and / or market conditions, based on research and market analysis. For more information on the Synapse Team's methodology for modeling distributed solar, including policies modeled and load profiles, see Section 4.4: *Renewable energy* .

This component is included in all counterfactuals and does not differentiate between programmatic or non-programmatic components.

[114] Chandrasekaran, R. August 26, 2020. "Electric Vehicles Market to Get Back on Track Post-COVID-19." *Wood MacKenzie*. Available at: https://www.woodmac.com/news/opinion/electric-vehicles-market-to-get-back-on-track-post-covid-19/.

Other resources not modeled in AESC 2021

There are other emerging DSM programs (see Table 26) that may be modeled using the 8,760 avoided cost values. These resources are not modeled in any AESC 2021 counterfactuals.

Table 26. Current status of emerging DSM technologies

Technology	Other Components or Considerations
Conservation Voltage Reduction (CVR)	The traditional avoided costs streams may be applied for CVR programs. CVR occurs in front of the 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 (VVO)	The traditional avoided costs streams may be applied for VVO programs. VVO occurs in front of the 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.

Energy losses

Electric systems incur energy losses when delivering power from power plants to customer's sites through T&D wires. T&D losses are developed in AESC 2021 for two main reasons:

- First, the development of certain categories of load forecast components requires the conversion between retail electricity consumption and wholesale electricity impacts. In this case, T&D losses are inputs into the avoided costs.
- Second, readers of AESC 2021 may wish to apply a T&D loss factor to convert the wholesale avoided costs calculated in AESC into retail avoided costs. In this case, T&D loss factors are applied to modeling outputs.

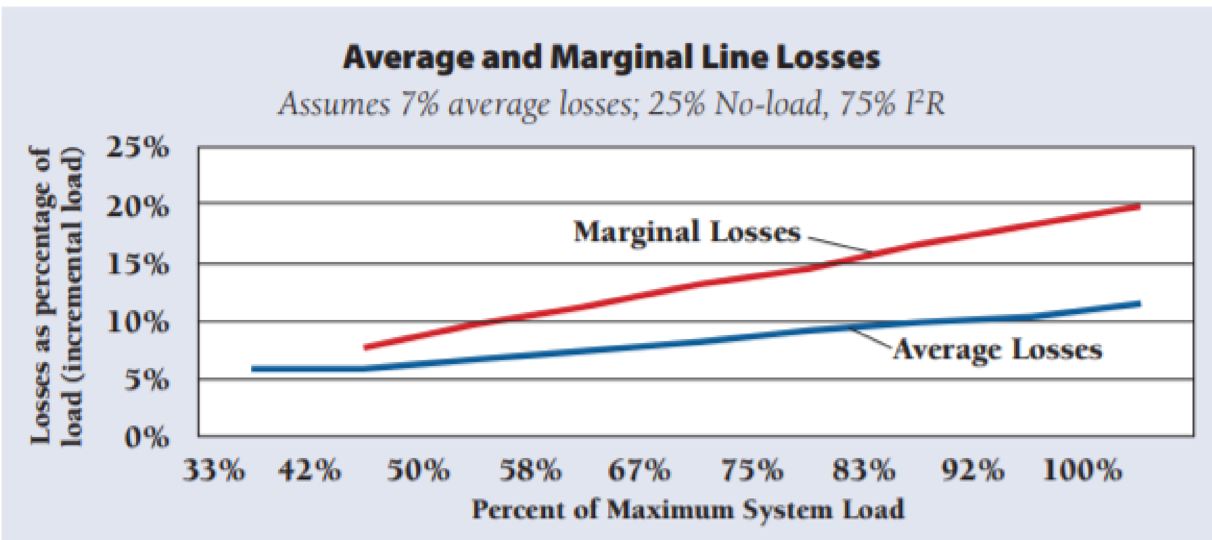
The following section is primarily concerned with the development of the T&D losses under the first category, as it is our understanding that each program administrator calculates and applies (or uses a T&D loss factor based on state precedent). However, readers may wish to review the following section to help inform their selection of loss factors.

Marginal loss factors

The amount of energy loss is affected by a number of factors including resistance in wires, system utilization rates, and weather conditions. Energy losses are generally higher when loads are higher and significantly higher during peak periods because resistive losses in wires increase with the square of the load (loss power = I^2R). This means that line losses for incremental loads ("marginal losses") that would be avoided by DSM programs are likely higher than average line losses. On the other hand, a certain amount of loss, ranging from 20 percent to 30 percent of the entire loss, are "no-load losses" that do not increase with the square of the current, unlike resistive losses. These losses incur to energize the system (i.e., create a voltage available to serve a load).[115] This means that the influence of resistive losses is greater at higher load levels because the impact of the no-load losses is fixed and relatively smaller at higher load levels.

A 2011 Regulatory Assistant Project (RAP) paper, "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements," discusses in detail line loss factors. This paper presents an example of line loss factors and demonstrates how marginal and average losses vary at different system load levels as shown in Figure 25. This figure shows that the increases in marginal losses are greater than the increases in average losses as the system load levels increase. For example, when the system is loaded at 50 percent of the capacity, average and marginal losses are approximately 6 percent and 8 percent respectively, and when the load is near its capacity, average and marginal losses are approximately 12 percent and 20 percent respectively.

Figure 25. Average and marginal line loss factors from Lazar and Baldwin (2011)



Source: Reproduced from Figure 4 in "Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements." (2011) Regulatory Assistance Project (RAP). Available at https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

In order to accurately estimate annual average marginal losses, we need to know detailed load data and system utilization rates for each hour of a year. However, details on system utilization rates are not readily available for ISO New England. The RAP paper suggests a rule of thumb value that marginal losses are about 1.5 times average losses. Thus, we use a factor of 1.5 to convert annual average line losses to marginal line losses. This value is also the value recommended by some stakeholders including one local utility in New Jersey and recently adopted by New Jersey Board of Public Utilities for

[115] RAP. 2011. Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements. Available at http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-eeandlinelosses-2011-08-17.pdf.

establishing the New Jersey Cost Test.[116] In AESC 2021, we apply a marginal loss factor to any incremental load added in a given year; all other portions of the load (i.e., the quantity that is less than or equal to the total load in the previous year) utilize an average loss factor. We use an average loss factor of 6 percent and a marginal loss factor of 9 percent (calculated by multiplying 6 percent by 1.5).[117]

For estimating marginal losses associated with capacity, we would need to know the system utilization factor at peak hours, or in other words, the degree to which the T&D system is stressed. While the utilization rates at the peak hours are by definition higher than the average rate for an entire year, detailed data for system utilization rates for the entire ISO New England grid for peak hours is not readily available. Thus, we rely on a larger factor than used for annual energy. Based on the data in Figure 25, factors for marginal losses over average losses range from 1.4 at a 50 percent system utilization factor to 2.6 at a 92 percent system utilization factor. Based on this range, we rely on a simple factor of 2.0. For the purposes of calculating the wholesale impact of load components (see above), we apply a marginal loss factor of 16 percent (calculated by multiplying 8 percent by a factor of 2.0) and an average loss factor of 8 percent to any existing demand (e.g., the quantity of demand in a year that is equal to or less than the previous year's demand).[118]

For more on applying energy losses to wholesale avoided costs, see Appendix B: *Detailed Electric Outputs*.

4.4. Renewable energy assumptions

See Chapter 7: *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* for more information on the assumptions used for renewable energy in AESC 2021's energy and capacity modeling. We describe additional assumptions on offshore wind interconnections below.

Offshore wind interconnection

The REMO Model provides information on projected offshore wind capacity and generation but does not specify where these facilities interconnect with New England's electric grid. We assume that all offshore wind that is built in southern New England is built in the U.S. Bureau of Ocean Energy Management's designated lease zones (see Figure 26). However, there is ongoing discussion on where these offshore wind facilities will interconnect. Options include locations on or near Cape Cod; New London or further west in Connecticut; Quonset, RI; Brayton Point, MA; or in the Greater Boston region.

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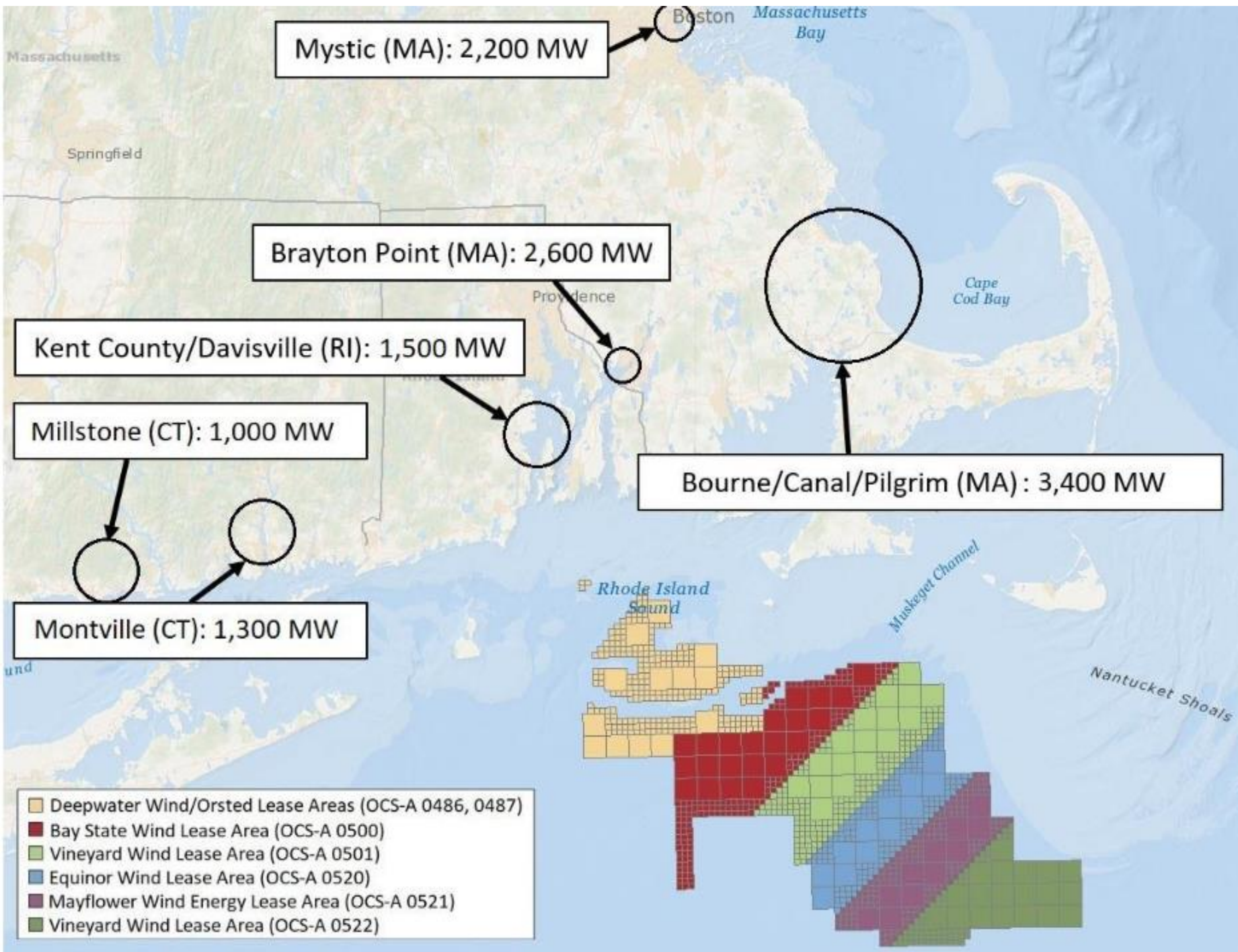
[116] New Jersey Board of Public Utilities. 2020. Order Adopting the First New Jersey Cost Test. Docket No. QO19010040 and QO20060389.

[117] Note that 6 percent is the average T&D loss factor assumed by ISO New England for long-term energy forecast. ISO New England. November 18, 2019. *Update on the 2020 Transportation Electrification Forecast.* Available at https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf.

[118] See ISO New England Market Rules, Section III.13.1.4.1.1.6.(a).

In order to minimize price anomalies, we distribute the offshore wind interconnection points throughout southern New England.[119] Although there is uncertainty about which interconnection points will be used, to what degree, and when, we rely on a simplified "cycling" methodology to allocate the offshore wind throughout various modeling zones. Using 800 MW blocks, we change the interconnection point of offshore wind projects as they are built, moving from Southeast Massachusetts, to Rhode Island, to Connecticut Northeast, to Boston, and back through again. By 2035, this produces interconnected quantities that are largely consistent with those described in two separate recent modeling studies by Anbaric and NESCOE.[120]

Figure 26. Bureau of Ocean Energy Management (BOEM) lease zones in southern New England and potential interconnection points



Source: Figure reproduced from https://www.iso-ne.com/static-assets/documents/2020/03/a8_anbaric_2019_economic_study_prelim_results_marpac.pdf, *slide 9.*

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[119] Through exploratory analysis in AESC 2021, we discovered that interconnecting all the offshore wind builds in the Southeast Massachusetts modeling zone produced very low energy prices in that zone and Rhode Island.

[120] ISO New England. "Anbaric 2019 Economic Study – Offshore Wind Results." March 18, 2020. Available at https://www.iso-ne.com/static-assets/documents/2020/03/a8_anbaric_2019_economic_study_prelim_results_marpac.pdf. Page 51.

4.5. 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. 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 expected to occur during the analysis period.[121]

Nuclear units

There are two remaining nuclear plants in New England: Seabrook (located in New Hampshire) and Millstone (located in Connecticut). Seabrook has one unit, and Millstone has two (see Table 27). None of the three units have announced a retirement date within the AESC 2021 analysis period. In the recent past, the Nuclear Regulatory Commission (NRC) relicensed Pilgrim 1 (previously located in Massachusetts and retired in May 2019), Millstone 2, and Millstone 3—along with many other reactors outside New England—without denying a single extension.[122] 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 all three nuclear units continue to operate throughout the entire modeling period.[123]

Table 27. Nuclear unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	Current License Expiration Date
Seabrook 1	NH	1,242.0	None	March 2050
Millstone 2	CT	909.9	None	July 2035
Millstone 3	CT	1,253.0	None	November 2045

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

Coal units

As of August 2020, there are three coal units operating in New England, spread across two power plants (see Table 28). Other recently retired plants include Brayton Point (retired June 2017), Mount Tom (retired June 2014), Salem Harbor (retired June 2014), and Schiller (retired July 2020).

[121] 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.

[122] NEI. Last accessed March 10.2021. "Nuclear Energy in the U.S." *Nei.org*. Available at https://www.nei.org/resources/statistics.

[123] These assumptions are consistent with those assumed by ISO New England in its 2019 Regional System Plan (see https://www.iso-ne.com/static-assets/documents/2019/10/rsp19_final.docx, page 152), with the addition of an assumed license extension for Seabrook 1.

Of the remaining units, Bridgeport Station 3 has already announced a retirement date. The Merrimack units have undergone substantial environmental retrofits in recent years. In this analysis, we make the below assumptions for these units' future operation.

Merrimack

The Merrimack power plant consists of two coal-fired units, and two 19-MW gas-fired combustion turbines. The two coal units at Merrimack were built in 1960 and 1968, making the units 52 and 60 years old, respectively, as of 2020. Both Merrimack coal units feature a wet fluidized gas desulphurization (FGD) system to control for SO_2, a selective catalytic reduction (SCR) system to control for NO_X, and an electrostatic precipitator (ESP) to control for particulate matter. Merrimack 1 operated at a capacity factor of 7 percent in 2019 and 2 percent in the first six months of 2020; Merrimack 2 operated at 8 percent and 3 percent in those same periods. All four Merrimack units have capacity commitments through FCA-14 (i.e., through May 31, 2024). Consistent with AESC 2018, we assume that both Merrimack 1 and Merrimack 2 retire on January 1, 2025, and that the other two (gas-fired) Merrimack units are operational throughout the analysis period.

Table 28. Coal unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	Modeled Retirement Date
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

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

Natural gas and oil units

Throughout the study period, we assume over 40 MW of new capacity additions from natural gas or oil resources. Table 29 lists the units added exogenously during the study period. Data on capacities and online dates are from EIA's Form 860 and the FCM. These resources are assumed to be primarily natural gas-fired.

Table 29. Incremental natural gas and oil additions

Unit	State	Capacity (MW)	Modeled Online Date	Unit Type
MIT Central Utilities/Cogen Plant GT200	MA	21.7	Feb 2021	Combustion Turbine
MIT Central Utilities/Cogen Plant GT300	MA	21.7	Feb 2021	Combustion Turbine
Killingly	CT	632	Oct 2023	Combined Cycle

In addition, there are a number of major natural gas- and oil-fired units which are assumed to retire during the study period (see Table 30). 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 30. Major natural gas and oil retirements

Unit	State	Capacity (MW)	Announced / Modeled Retirement Date	Unit Type	Notes
Mystic Generating Station 7	MA	617.0	June 2021	Steam Turbine	-
Mystic Generating Station GT1	MA	14.2	June 2021	Combustion Turbine	-
Mystic Generating Station GT81	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station GT82	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station GT93	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station GT94	MA	278.6	June 2024	Combined Cycle	-
Mystic Generating Station ST85	MA	315.0	June 2024	Combined Cycle	-
Mystic Generating Station ST96	MA	315.0	June 2024	Combined Cycle	-
Cleary Flood 8	MA	28.3	June 2023	Steam Turbine	-
Pawtucket Power Associates GEN1	MA	41.8	June 2022	Combined Cycle	-
Pawtucket Power Associates GEN2	MA	27.0	June 2022	Combined Cycle	-
Mass Inst Tech Cntrl Utilities/Cogen Plt CTG1	MA	21.2	Feb 2021	Combustion Turbine	-
Cape Gas Turbine GT4	MA	17.5	June 2022	Combustion Turbine	No FCA oblig. in Jun 2022
Cape Gas Turbine GT5	MA	17.5	June 2022	Combustion Turbine	No FCA oblig. in Jun 2022
William F Wyman Hybrid (Yarmouth) 1	ME	50.0	June 2020	Steam Turbine	No FCA oblig. in Jun 2020
William F Wyman Hybrid (Yarmouth) 2	ME	50.0	June 2020	Steam Turbine	No FCA oblig. in Jun 2020
William F Wyman Hybrid (Yarmouth) 3	ME	113.6	June 2022	Steam Turbine	No FCA oblig. in Jun 2022
William F Wyman Hybrid (Yarmouth) 4	ME	632.4	June 2022	Steam Turbine	No FCA oblig. in Jun 2022
Middletown 2	CT	113.6	June 2022	Steam Turbine	No FCA oblig. in Jun 2022
Middletown 4	CT	414.9	June 2023	Steam Turbine	No FCA oblig. in Jun 2023

Unit	State	Capacity (MW)	Announced / Modeled Retirement Date	Unit Type	Notes
Middletown 10	CT	18.5	June 2023	Steam Turbine	No FCA oblig. in Jun 2023
Essential Power Massachusetts LLC (West Springfield) 3	MA	113.6	June 2023	Steam Turbine	No FCA oblig. in Jun 2023
Maine Independence Station GEN1	ME	177.8	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Maine Independence Station GEN2	ME	177.8	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Maine Independence Station GEN3	ME	194.6	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Capitol District Energy Center (CDECCA) GTG	CT	39.8	June 2023	Combined Cycle	No FCA oblig. in Jun 2023
Capitol District Energy Center (CDECCA) STG	CT	30.7	June 2023	Combined Cycle	No FCA oblig. in Jun 2023

We note that after the modeling phase of this project had concluded, ISO New England posted detailed data on resource additions and retirements identified through FCA 15.[124] Large, notable additions include a 60 MW capacity addition at Ocean State Power in RI, 150 MW of new battery storage at Cranberry Point Battery Energy Storage in MA, 250 MW of new battery storage at Medway Grid in MA, 175 MW of new battery storage at Resource Cross Town in ME, and 20 MW of new battery storage at Great Lakes Millinocket in ME. Large notable addition include a 95 MW retirement at West Springfield 3 in MA. We expect that the inclusion of these changes would likely have limited impacts on projections of avoided energy costs, avoided capacity costs, and other avoided cost categories. We note that there are numerous uncertainties in any projection of the future as new resources are announced and others are retired and that future modeling efforts should endeavor to include the impacts of these resource changes.

Other resources

Note that our analysis also includes several 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.

[124] ISO New England. Last Accessed March 10, 2021. *FCA Obligations.* Available at https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx.

Other resources (e.g., biomass, wind) may have specific retirement dates.[125] These retirements and additions are accounted for in Section 4.4: *Renewable energy* .

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 31 if it is determined there is a peak demand need. These parameters are similar, but not identical, to the parameters assumed in the 2018 AESC Study. 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.[126]

Table 31. Characteristics of generic conventional resources assumed in the EnCompass model

		Natural gas-fired combined cycle	Natural gas-fired combustion turbine
Maximum size	*MW*	702	237
Minimum size	*MW*	225	120
Heat rate	*Btu/kWh*	7,408	9,800
Variable O&M costs	*2021 $/MWh*	3.80	3.84
Fixed O&M costs	*2021 $/kW-yr*	11.93	19.16
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.

In addition to the exogenous storage builds described above, EnCompass can build out two- and four-hour duration storage resources if it determines it is optimal to do so. For these additional storage resources, we rely on capital expenditure data from the National Renewable Energy Laboratory's (NREL) 2020 Annual Technology Baseline (ATB).[127] NREL's 2020 ATB assumes that two-hour duration storage resources have capital expenditures of $963 per kW in 2018 before declining to $607 per kW in 2030 and thereafter increasing slightly to $647 per kW in 2040 (all values in nominal dollars). It assumes that four-hour duration storage resources have capital expenditures of $1,633 per kW in 2018 before declining to $1,029 per kW in 2030 and thereafter increasing slightly to $1,098 per kW in 2040 (all values in nominal dollars).

In general, the model builds new storage resources to meet reserve margin requirements as peak demand increases. As the model optimizes to meet a region's reserve margin requirement, it often finds

[125] These retirements include Pinetree Power (MA) in June 2022.

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

[127] National Renewable Energy Laboratory. Last accessed March 10, 2021. "Battery Storage." *Atb.nrel.gov.* Available at https://atb.nrel.gov/electricity/2020/index.php?t=st.

that storage resources are the most cost-effective resource available. In AESC 2021, we use a five-year optimization horizon, wherein the EnCompass model looks over the next five years to evaluate reliability requirements and costs in order to retire or build capacity as necessary.[128]

4.6. Transmission, imports, and exports

This section describes the existing, under construction, and planned intra-regional transmission modeled in the AESC 2021 study. It also describes our assumptions on new transmission between New England and other adjacent balancing authorities, and how we model imports over these inter-regional transmission lines in the analysis.

Intra-regional transmission

The interface limits used in the AESC 2021 study reflect both the existing system and the ongoing transmission upgrades discussed in ISO New England's Regional System Plan.[129] The transmission paths that link each of the 13 modeled regions in New England are based on transmission limits published by ISO New England (see Table 32).[130]

[128] Earlier AESC studies typically used one-year optimization horizons, largely because of computing power limitations. We have selected a five-year optimization horizon because this is roughly the horizon used to conceptualize and build large power plant projects (the FCM has a three-year horizon, but projects are conceptualized and qualified in the market before each auction at least one year and possibly more). When comparing resulting avoided costs in AESC 2021 with earlier studies, the most likely impact of this change in optimization horizon is to reduce "noise." In other words, this change is unlikely to cause avoided costs to be lower or higher but is more likely to reduce the year-on-year variation in costs.

[129] Regional System Plan documents can be found on ISO New England's website at https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

[130] 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). In response to this, we model a new 600 MW transmission line between Maine West Central and Massachusetts Central beginning in 2023. The transmission line is intended to help limit issues of curtailment in Massachusetts.

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	3,000	
	NE New Hampshire - NE Vermont			
	NE Rhode Island - NE Connecticut Northeast			
NE North-South	NE New Hampshire - NE Boston	2,725	2,725	
	NE New Hampshire - NE Massachusetts Central			
	NE Vermont - NE Massachusetts West			
	Hydro Quebec - NE Massachusetts Central			
NE SEMA/RI	NE Massachusetts Southeast - NE Boston	1,800	3,400	
	NE Rhode Island - NE Boston			
	NE Rhode Island - NE Connecticut Northeast			
	NE Rhode Island - NE Massachusetts Central			
NE Southeast	NE New Hampshire - NE Boston	5,150		
	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	2,800		
	NE Connecticut Northeast - NE Connecticut Southwest			
NE Connecticut	NE Connecticut Northeast - NY K Long Island	3,400	3,400	
	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	-1,400 to 1,875
	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
Quebec	Hydro Quebec - NE Vermont	2,000	2,000	
	Hydro Quebec – NE Massachusetts Central	217	100	
Cross Sound	NE Connecticut Northeast - NY K Long Island	variable	variable	-177 to 333

Inter-regional transmission

In addition, we model 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 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. Imports 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 (see Table 33).

Table 33. Single pathway transmission limits with regions adjoining ISO New England

Zone A	Zone B	A to B Capacity (MW)	B to A Capacity (MW)
NE Connecticut Northeast	NY G Hudson Valley	600	600
NE Connecticut Northeast	NY K Long Island	330	330
NE Maine Northeast	NE Maine West Central	1,325	
NE Maine Northeast	New Brunswick	1,000	1,000
NE Maine Southeast	NE Maine West Central		1,500
NE Maine Southeast	NE New Hampshire	1,900	
NE Massachusetts Central	Hydro Quebec	217	217
NE Massachusetts West	NY F Capital	700	700
NE Norwalk Stamford	NY K Long Island	100	100
NE Vermont	Hydro Quebec	2,000	2,000

In addition, we model an incremental 1,200 MW transmission line from Québec to southeast Maine, per the topology of the New England Clean Energy Connect (NECEC) project.[131] This line is modeled as providing 9.45 TWh per year. This transmission line represents compliance with Massachusetts' 2017 Act to Promote Energy Diversity, and the associated long-term contracts signed per that legislation. Under Massachusetts Chapter 188 Section 83D, any contracts selected from the 83D solicitation process must be executed by no later than December 31, 2022. Per the latest data available, we assume that this line will instead be energized on July 1, 2023. Because this cost is assumed to be unavoidable to Massachusetts ratepayers, we do not develop or incorporate a price for this resource at this time.

4.7. Operating unit characteristics

Under the production cost modeling framework, EnCompass represents the detailed operations of individual generating units. This representation includes detail on following operational characteristics for dispatch data:

- Unit type (steam-cycle, combined-cycle, simple-cycle, cogeneration, etc.)

[131] See the New England Clean Energy Connect website at https://www.necleanenergyconnect.org/ for more information.

- Fuel type (including dual-fuel capabilities, startup fuel usage, and fuel delivery point or basin of origin)
- Heat rate values and curve
- Seasonal capacity ratings (maximum and minimum)
- Variable operation and maintenance costs
- Commitment bid adders and multipliers
- Forced outage rates and planned outage rates and schedules
- Minimum up and down times, including maximum hours for warm and hot start scenarios
- Quick start, regulation, and spinning reserves capabilities
- Startup costs
- Ramp rates
- Emission rates (SO_2, NO_X, and CO_2) with options for fixed, linear, quadratic, cubic, and quartic rates
- Seasonal and/or hourly capacity factor profiles for hydro, wind, and solar resources
- Acceptable curtailment levels for hydro, wind, and solar resources
- Storage charge and discharge rates (in MW), maximum energy-stored levels (in MWh), and payback rates for pumped hydropower and battery storage

Unit operational restraints (for example, minimum up times and ramp rates) are used to simulate unit commitment for hourly, chronological model runs. During unit operations, units incur costs based on fuel usage, variable O&M costs, and emission costs. Operational units also receive revenue based on their provision of grid services, including energy, regulation, and reserve services. Every model run produces an estimate of each unit's profitability given a dispatch pattern optimized to produce the lowest overall electric system costs for the region.

O&M costs for existing conventional generation are based on unit-specific data contained in EnCompass. Capital, operating, and maintenance costs and heat rate for new conventional generation are based on data from the 2017 AEO.

4.8. Embedded emissions regulations

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

The Regional Greenhouse Gas Initiative

All six New England states are founding members of RGGI. Under the current program design, the six states (along with New York, Maryland, Delaware, and New Jersey) conduct four auctions in each year in which CO_2 allowances are sold to emitters and other entities.

In August 2017, the RGGI states announced a set of proposed program changes for Years 2021 through 2030.[132] Under this extended program design, the RGGI states will continue to reduce CO_2 emissions through 2030, eventually achieving a CO_2 emissions level 30 percent below 2020 levels. This new program design has 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). Together, these triggers effectively act as a floor and ceiling on RGGI prices.[133]

In addition, in recent years, the RGGI region has begun to expand. The first new state to join RGGI was New Jersey in January 2020 (rejoining the program after leaving it in 2012).[134] Later in 2020, Virginia finalized its rulemaking to join RGGI, effective January 1, 2021.[135] Finally, Pennsylvania is also developing a draft regulatory proposal to join RGGI (with the state slated to on January 1, 2023), though this rulemaking remains ongoing.[136]

Starting in April 2020, Pennsylvania Department of Environmental Protection tasked ICF International with developing RGGI price projections under a base case and a case where Pennsylvania joins the 11-state RGGI region. ICF International is the same firm that typically creates RGGI price forecasts on behalf of RGGI, Inc. This includes the RGGI price modeling generated in the 2016 RGGI Program Design, which served as the basis for RGGI prices in the 2018 AESC Study.[137]

Figure 27 displays the recent prices for RGGI allowances from auctions in 2010 through 2020. The figure includes a trajectory through 2030 where Pennsylvania does not join RGGI, plus a trajectory where

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[132] The official announcement ca be found on the RGGI website at http://rggi.org/docs/ProgramReview/2017/08-23-17/Announcement_Proposed_Program_Changes.pdf.

[133] Regional Greenhouse Gas Initiative. December 19, 2017. “RGGi 2016 Program Review: Principles to Accompany Model Rule Amendments” *Rggi.org.* Available at rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf.

[134] New Jersey Department of Environmental Protection. Last accessed March 10, 2021. “Regional Greenhouse Gas Initiative.” *state.ny.us.* Available at https://www.state.nj.us/dep/aqes/rggi.html.

[135] Virginia Department of Environmental Quality. Last accessed March 10, 2021. “Carbon Trading.” *Deq.virginia.gov.* Available at https://www.deq.virginia.gov/air/greenhouse-gases/carbon-trading.

[136] Pennsylvania Department of Environmental Protection. Last accessed March 10, 2021. “Regional Greenhouse Gas Initiative.” *Dep.pa.gov.* Available at https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx.

[137] Regional Greenhouse Gas Initiative. Last accessed March 10. 2021. “Program Review.” *Rggi.org.* Available at https://www.rggi.org/program-overview-and-design/program-review.

Pennsylvania does join RGGI. The RGGI price trajectory used in AESC 2018 is also shown, for reference. This figure also shows the prices associated with the emissions containment reserve (ECR) and cost containment reserve (CCR). Although two states (Maine and New Hampshire) do not use the ECR (the floor price), emissions from these two states make up a small fraction of RGGI-wide emissions and are unlikely to have a substantial effect on the price.

Because the RGGI region includes states not modeled in the AESC 2021 study (New York, Delaware, Maryland, New Jersey, Virginia, and Pennsylvania) and is in fact dominated by emissions outside of New England (see Figure 28), we model the effects of RGGI as an exogenous price rather than a strict cap on emissions. Note that neither of the scenarios recently modeled by ICF International displayed in Figure 27 exactly represent the assumptions used for the New England electricity system throughout this report (for example, they do not include any assumptions about transportation electrification, and both assume some amount of energy efficiency persists through 2030). Both of them indicate prices lower than what is implied by the ECR, in at least some years. Prices lower than the ECR are possible in situations where the full ECR (e.g., 10 percent of the allowances sold in any given auction) is withheld and there is still not enough demand at the trigger price for the remaining allowances. If only some of the ECR needs to be withheld, then the price will match the ECR trigger price.

The RGGI price modeled in AESC 2021 follows the ECR price (and follows a trajectory that extends the ECR's 2020 to 2030 CAGR to 2031 to 2035). This trajectory reflects a future in which reductions in the RGGI cap are continued after the current compliance period ends in 2030, and a future in which New England electricity demand is higher than recently modeled by ICF International.

Figure 27. Historical RGGI allowance prices, recently modeled RGGI allowance prices, the prices associated with the cost containment reserve (CCR) and emissions containment reserve (ECR), and RGGI price used in AESC 2021

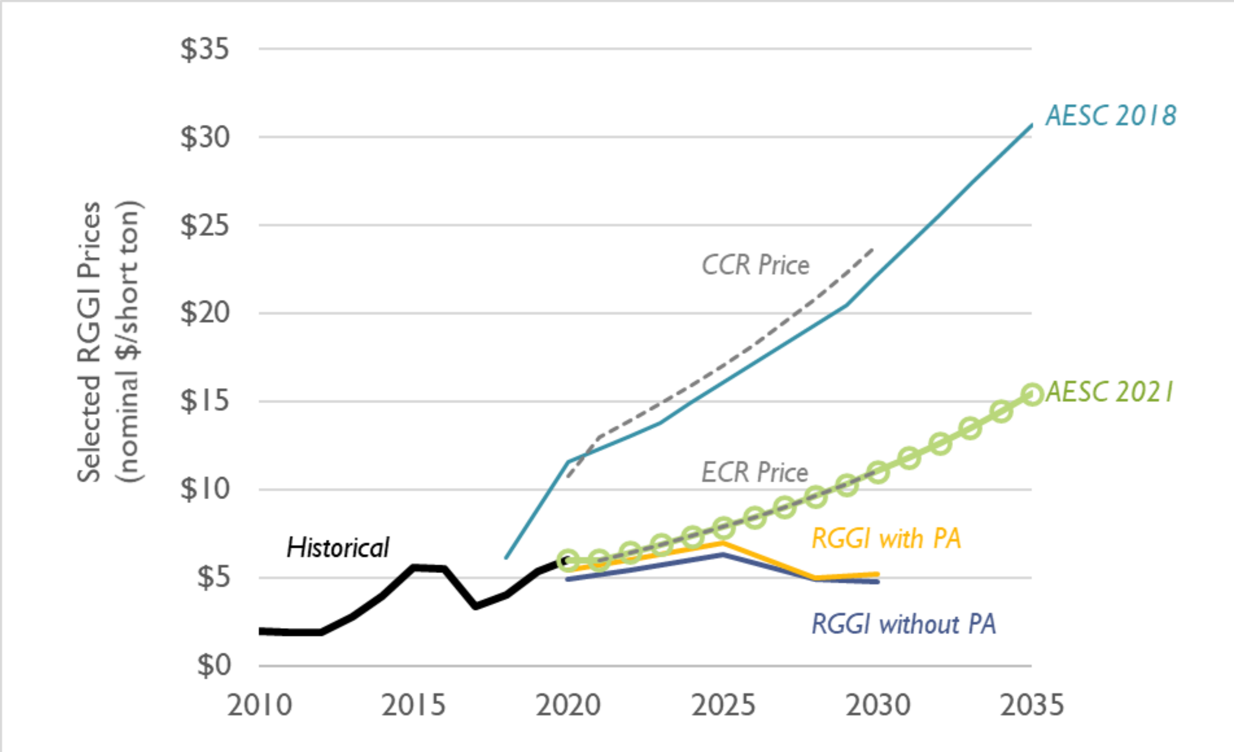
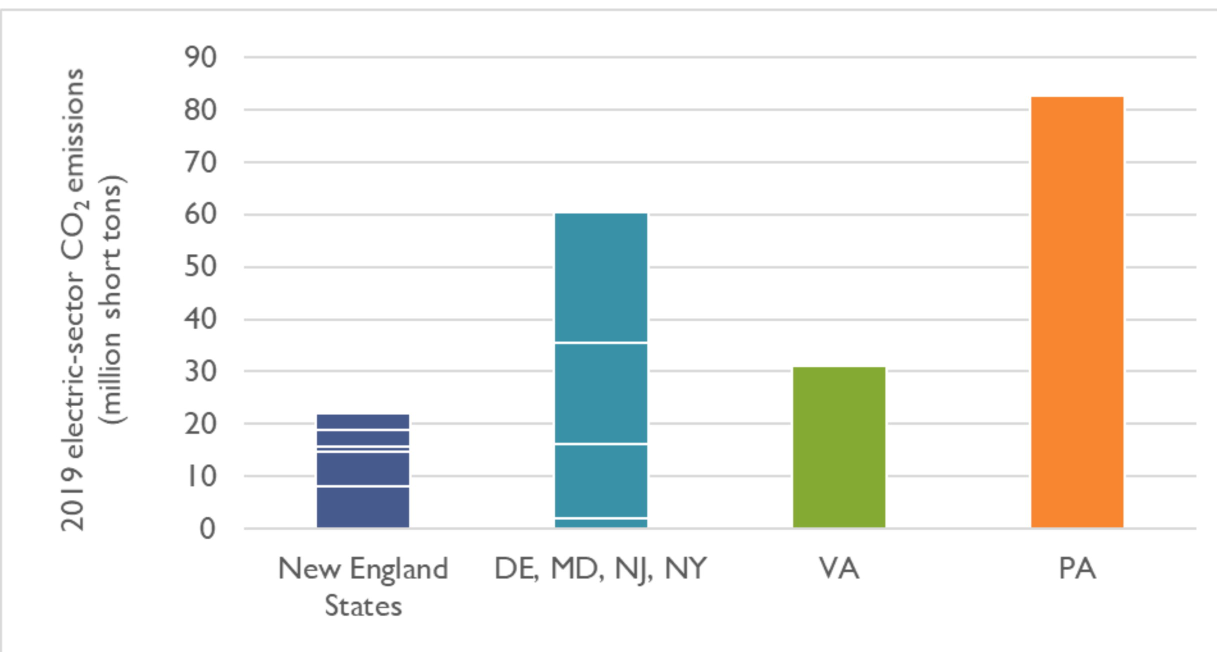


Figure 28. Electric sector CO_2 emissions in existing and proposed RGGI states, 2019



Source: EPA Air Market Programs dataset, available at ampd.epa.gov.

Massachusetts Global Warming Solutions Act and MassDEP regulations

AESC 2021 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: .

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 34 lists the affected power plants under this regulation. In the AESC 2021 study, we model 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.[138] 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 Table 24).[139]

In this analysis, we assume that both new and existing units fall under the same aggregate limit, as was done in the 2018 AESC study. 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 do not model ACPs or banking of CO_2 allowances pursuant to 310 CMR 7.74.

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

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

Figure 29. Analyzed electric sector CO_2 limits under 310 CMR 7.74

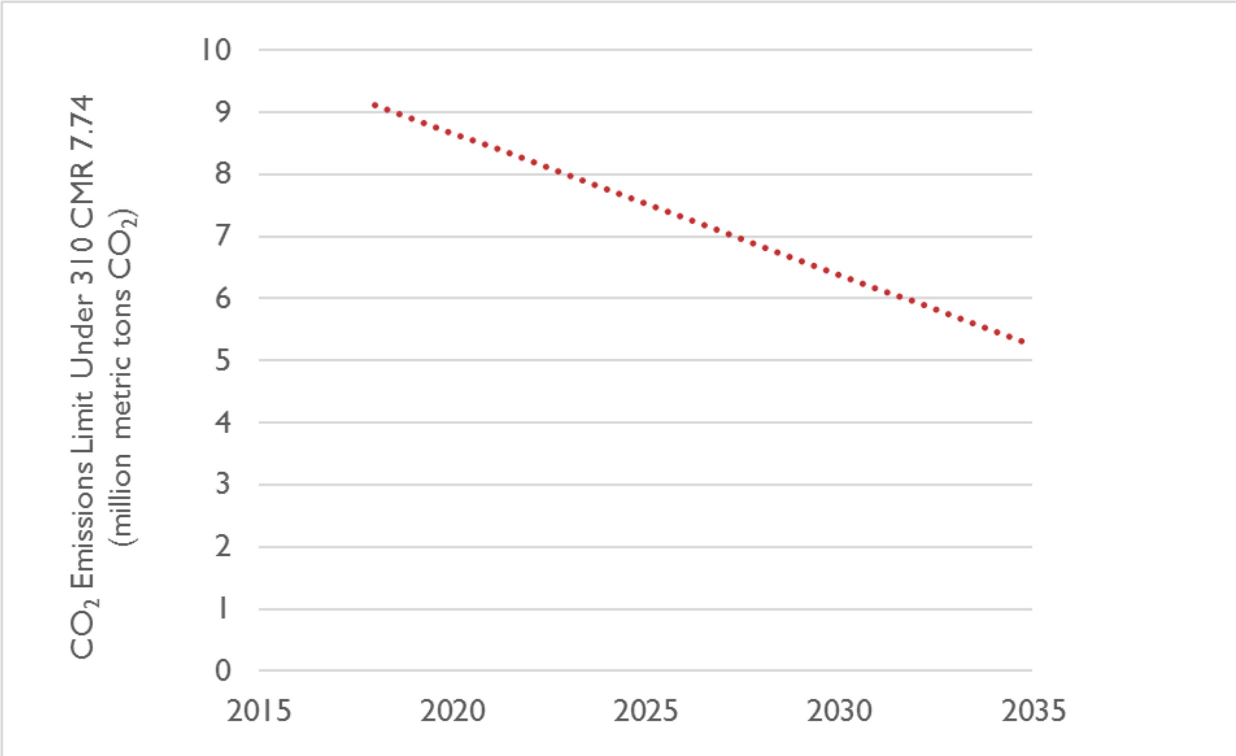


Table 34. List of generating units modeled as subject to 310 CMR 7.74

ORSPL	Facility	Unit Type	Fuel Type	Online Year (if recent)	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

Note: This list includes some units that are modeled as retiring at some point in the study period.

310 CMR 7.75: Clean Energy Standard

This regulation establishes additional tranches of clean energy that are eligible to qualify for Clean Energy Certificates. More information on how we modeled this regulation (along with recent regulations for existing energy that were finalized in 2020) can be found in Section 4.4: *Renewable energy* .

Other environmental regulations

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

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 weighted average allowance prices from the 2020 SO_2 spot auction ($0.02 per short ton) for SO_2 are escalated at the rate of inflation through the study period, where SO_2 allowances are trading at a transaction cost.[140] These assumed prices are lower than the prices assumed in AESC 2018 ($0.52 per short ton, in 2018 dollars).

In AESC 2021 we assume no embedded 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 being modeled in previous AESC studies.

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 electric-sector regulations aimed at requiring that electric-sector emissions remain under a specified cap in some future year. In the AESC 2021 analysis, we do not include any embedded costs of GHG reduction compliance from states other than Massachusetts, and we assume no additional electric-sector regulations to those put forth under 310 CMR 7.74 and 7.75.[141]

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[140] U.S. EPA. Last accessed March 10,2021. "2020 SO_2 Allowance Auction." *EPA.gov*. Available at https://www.epa.gov/airmarkets/2020-so2-allowance-auction#tab-2.

[141] Note that AESC 2021 does not assume that the full costs of the Massachusetts GWSA—or any other states' climate goals—are embedded in the energy prices and CES compliance prices. AESC 2021 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 and similar goals, targets, and requirements, 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 in many cases, not yet established.

Table 35. State-specific GHG emission reduction targets 2050

State	2050 Target	Category	Sources	Interim Targets / Notes
CT	80% below 2001 levels	Statutory Target	Substitute House Bill No. 5600 Public Act 08-98: "An Act Concerning Global Warming Solutions" (Global Warming Solutions Act, or GWSA). See https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm	Senate Bill No. 7 Public Act No. 18-82 An Act Concerning Climate Change Planning and Resiliency. This 2018 Act established an interim goal of 45% below 2001's GHG emissions level by January 1, 2030. Available at https://www.cga.ct.gov/2018/act/pa/pdf/2018PA-00082-R00SB-00007-PA.pdf
ME	80% below 1990 levels by January 1, 2050	Statutory Target	38 MRSA §576-A. Greenhouse gas emissions reductions. See http://www.mainelegislature.org/legis/statutes/38/title38sec576-A.html	The legislation has the following interim goals: (a) Reduce GHG emissions by 45 percent by January 1, 2030 and (b) by January 1, 2040, the gross annual GHG emissions level must, at a minimum, be on an annual trajectory sufficient to achieve the 2050 annual emissions level.
MA	Net zero emission by 2050; gross emissions must be at least 85% below 1990 levels	Statutory Target	2008, Chapter 298 An Act Establishing the Global Warming Solutions Act. See https://malegislature.gov/laws/sessionlaws/acts/2008/chapter298 and https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download	Statutory target set at 80% below 1990 levels by 2050; GWSA requires the Executive Office of Energy and Environmental Affairs to set economy-wide GHG emission reduction goals for 2020, 2030, 2040, and 2050.
NH	80% below 1990 levels	Executive Target	2009 New Hampshire Climate Action Plan. See https://www.des.nh.gov/organization/divisions/air/tsb/tps/climate/action_plan/documents/nhcap_final.pdf	n/a
RI	80% below 1990 levels	Statutory Target	TITLE 42, State Affairs and Government, Chapter 42-6.2 Resilient Rhode Island Act of 2014 – Climate Change Coordinating Council, Section 42-6.2-2. See http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/42-6.2-2.HTM	Interim targets below 1990 levels include: (a) 10 percent below 1990 levels by 2020 and (b) 45 percent below 1990 levels by 2035;
VT	75% below 1990 levels	Statutory Target	Title 10 V.S.A. § 578 Conservation And Development Chapter 023: Air Pollution Control. See https://legislature.vermont.gov/statutes/section/10/023/00578	Interim targets below 1990 levels include: (a) 25 percent by January 1, 2012 and 50 percent by January 1, 2028.

Note: "Category" uses definitions from https://www.c2es.org/document/greenhouse-gas-emissions-targets/.

Federal CO_2 policies

In August 2018, the U.S. Environmental Protection Agency (EPA) announced a successor policy to the Clean Power Plan in the form of the Affordable Clean Energy (ACE) rule.[142] In January 2021, the D.C. Circuit vacated the ACE Rule and remanded it to EPA.[143] While other plans for federal action on CO_2 have been discussed in recent years, there are currently no regulations or policies in federal rulemaking. AESC 2021 models no other federal CO_2 policies.

[142] Synapse has written a short summary of an earlier ACE proposal at https://www.synapse-energy.com/about-us/blog/ace-whats-cards-emissions-reductions-0.

U.S. EPA. Last accessed March 11, 2021. "Affordable Clean Energy Rule." Epa.gov. Available at https://www.epa.gov/stationary-sources-air-pollution/affordable-clean-energy-rule.

[143] United States Court of Appeals USCA Case #19-1140. October 8, 2020. *American lung Association and American Public Health Association V. Environmental Protection Agency and Andrew Wheeler, Administrator, Respondents.* Available at https://statepowerproject.files.wordpress.com/2021/01/american-lung-assn-v.-epa-dc-cir.-no.-19-1140-per-curiam-decision.pdf.

5. AVOIDED CAPACITY COSTS

AESC 2021 develops avoided capacity prices for annual commitment periods starting in June 2021. The avoided capacity costs are driven by actual and forecasted clearing prices in ISO New England's FCM. The AESC 2021 forecast prices are based on observations made in recent auctions as well as expected future changes in demand, supply, and market rules. These prices are applied differently for cleared measures (i.e., measures that participate in the capacity market) and uncleared measures (i.e., measures that do not participate in the capacity market).[144]

We find that in Counterfactual #1, capacity prices range from $2.80 per kW-month to $4.34 per kW-month in 2021 dollars. Market-clearing prices in the out-years are principally determined by future changes in supply (including additions of battery storage, solar, wind, and occasionally new natural gas-fired power plants; as well as and retirements of thermal generation) and future changes in demand. Small year-on-year variations are due to changes in load, new resources coming online, and other resources retiring.

Compared to AESC 2018, capacity prices in AESC 2021 are about half as large on a 15-year levelized basis. In general, Counterfactual #2 has lower capacity prices due to a lower projection of load, while prices in Counterfactual #1, Counterfactual #3, and Counterfactual #4 are relatively similar due to similar projections of annual loads. Small year-on-year observed differences are due to changes in load, new resources coming online, and other resources retiring.

5.1. Wholesale electric capacity market inputs and cleared capacity calculations

The following section provides a description of the analysis used to develop avoided capacity prices from the FCM auctions, as well as key input assumptions.

Description of Forward Capacity Market analysis

AESC 2021 develops avoided capacity prices from the FCM auction prices for power-years from June 2020 onward, using the actual results in auctions for delivery years 2021/22 through 2024/25 (FCAs 12 through 15) and extrapolating the historical results for the rest of the analysis period. The major assumptions used to simulate the future operation of the FCM include*:*

- ISO New England will continue to operate the FCM in a manner similar to recent years, including using a similarly shaped demand curve.

[144] "Uncleared resources" includes resources that qualify for the FCM but do not receive an obligation, as well as resources that simply do not participate in the market at all. They can also be thought of as "non-market" resources.

- Resources generally continue to bid FCM capacity in a manner similar to their bidding in FCA 9 through FCA 15. 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 build-out of the transmission system and additions of capacity in southern New England, as well as restrictions on the shifting of resources among zones in the *Competitive Auctions with Sponsored Resources* (CASPR) program, will minimize the risk of separation of capacity prices among the internal ISO capacity zones. The location of future potential zonal price spikes is difficult to assess; since the start of the FCM, ISO New England has observed or anticipated capacity-price separation for Maine, Connecticut, NEMA, northern New England (Vermont and New Hampshire), SEMA, SEMA-RI, and southeastern New England (NEMA, SEMA and Rhode Island). The transmission and ISO New England have made great efforts to eliminate binding capacity constraints between zones and have been successful since FCA 10.[145] We observed relatively minimal price separation in FCA 15, but we do assume no price separation in future years. Although it is possible that prices separation could occur in some future years, there is much uncertainty in terms of when this separation could occur, where it could occur, what level of price spread occurs, and how long the effect lasts. Thus, for purposes of simplicity, we assume a single regional clearing price in all modeled years.

- Retirements and additions of resources will change the amount of capacity in the low-price section of the supply curve, but the shape of the demand curve around the market-clearing point will remain similar to the shape of the supply curve in FCA 15.

- Due to retirements and load growth, FCM prices in the out-years are likely to be determined by the price of new resources, net of energy profits and operating-reserve revenues. Those new resources may be combustion turbines, combined-cycle units, or battery storage.

- The capacity price is set in the primary FCA based on the bids of existing resources, new unsubsidized resources, subsidized resources that could clear without the subsidy, and imports. New state-mandated resources, such as purchases of Canadian hydro power and offshore wind, are assumed to continue to participate in a substitution auction under the CASPR program, in which they can contract to take over the capacity supply obligation (CSO) of a generation resource that clears in the primary FCA and elects to permanently retire, giving up its transmission rights.[146] Once a sponsored resource has cleared in the CASPR market, it is then considered an existing resource and is able to participate in the primary auction. The existence of the CASPR market should encourage uneconomic generators (including a large amount of fossil steam capacity) to bid low to

[145] The abrupt non-price retirement of the entire Brayton Point station and Vermont Yankee in FCA 8 resulted in insufficient competition in the entire ISO in FCA 8 and in SEMA/RI in FCA 9.

[146] The retiring resource may pay the sponsored resource to take over the obligation (at a price less than the FCA clearing price) or the sponsored resource may pay the retiring resource for the right to become an existing resource in future FCAs.

clear the FCA, with the intent of offloading their CSOs to sponsored resources.[147] Once they are recognized as existing resources, sponsored resources are likely to bid largely as price-takers, since they will not want to shut down. A detailed discussion of the CASPR market is found below in subsection titled *ISO New England's Competitive Auctions with Sponsored Resources initiative*.

- For purposes of simplification, we assume that all resources are paid a single-year price, rather than a multi-year price. The option to elect a multi-year price will no longer be allowed beginning in FCA 16.[148]

AESC 2021 incorporates these assumptions to estimate FCM prices for power years from June 2025 onward.

Input assumptions to FCM analysis

The analysis of future capacity prices utilizes the results of the four most recent forward capacity auctions (FCA 12 through FCA 15), which are among the only ISO New England FCAs to clear at bid prices, rather than an administrative limit.[149] Table 36 shows the Rest of Pool (ROP) results for each round of each auctions. As the price falls in each round, the ISO 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.

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[147] ISO New England requires that an existing capacity resource which seeks to participate in the substitution auction offer a Test Price that indicates its estimate of a price at which it would not earn enough revenues to cover its going-forward costs. This document is reviewed by ISO New England's Internal Market Monitor. It is not yet apparent that this mechanism will preclude many existing resources from clearing.

[148] U.S. Federal Energy Regulatory Commission. December 2, 2020. *Order on Paper Hearing 173 FERC ¶ 61,198.* Available at https://www.iso-ne.com/static-assets/documents/2020/12/el20-54-000_12-2-20_order_new_entrant_rules.pdf.

[149] FCA 9 and FCA 10 also cleared at bid prices.

Table 36. FCA price results by round (rest-of-pool results only)

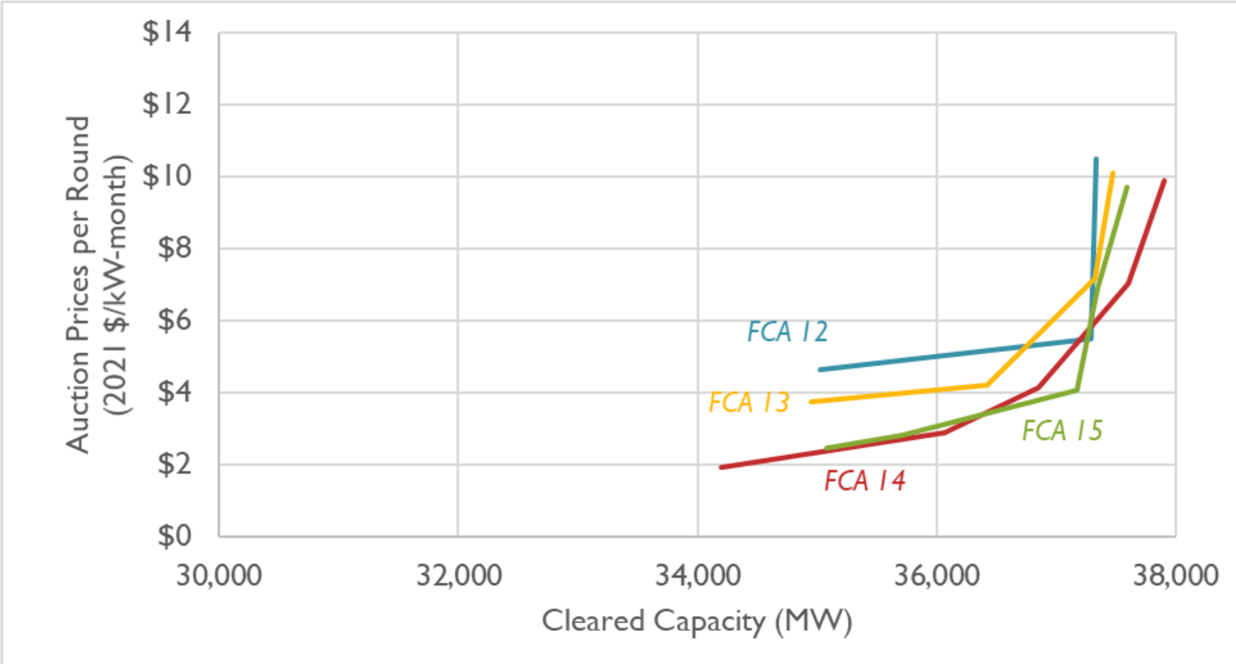
			CONE	Net CONE	Round 1	2	3	4	5
FCA 12	Price	*2021 $/kW-month*	$11.35	$8.04	$10.50	$8.00	$5.50	$4.63	
	Demand	*MW*			33,362	33,732	34,626	35,030	
	Excess	*MW*			3,972	3,589	2,669	0	
	Supply	*MW*			37,334	37,321	37,295	35,030	
FCA 13	Price	*2021 $/kW-month*	$11.07	$8.00	$10.30	$7.30	$4.30	$3.80	
	Demand	*MW*			33,437	33,897	34,724	34,954	
	Excess	*MW*			4,039	3,431	1,696	0	
	Supply	*MW*			37,476	37,328	36,421	34,954	
FCA 14	Price	*2021 $/kW-month*	$11.03	$7.87	$10.30	$7.30	$4.30	$3.00	$2.00
	Demand	*MW*			32,204	32,631	33,237	33,591	34,194
	Excess	*MW*			5,704	4,973	3,612	2,480	0
	Supply	*MW*			37,908	37,604	36,849	36,071	34,194
FCA 15	Price	*2021 $/kW-month*	$11.26	$8.20	$9.71	$6.88	$4.05	$2.83	$2.46
	Demand	*MW*			33,049	33,493	34,102	34,464	35,081
	Excess	*MW*			4,547	3,857	3,078	1,246	0
	Supply	*MW*			37,596	37,350	37,179	35,710	35,081

Notes: All prices have been converted to 2021 dollars.
Sources: See https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx and https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf.

Historical supply curves

Figure 30 shows the price results of the auction rounds, as a function of the supply available at that price. These are effectively the supply curves for capacity in each of these auctions. Each year, the market has been able to provide more capacity at a given price, or provide a given capacity at a lower price. The price curves for the last four auctions are relatively closely clustered and guide the AESC 2021 projection for future pricing. For future years, we move the FCA 15 supply curve right or left to reflect changes in capacity additions and retirements under each counterfactual.

Figure 30. FCA price results by round (effective supply curves)



Note: All prices have been converted into 2021 dollars.

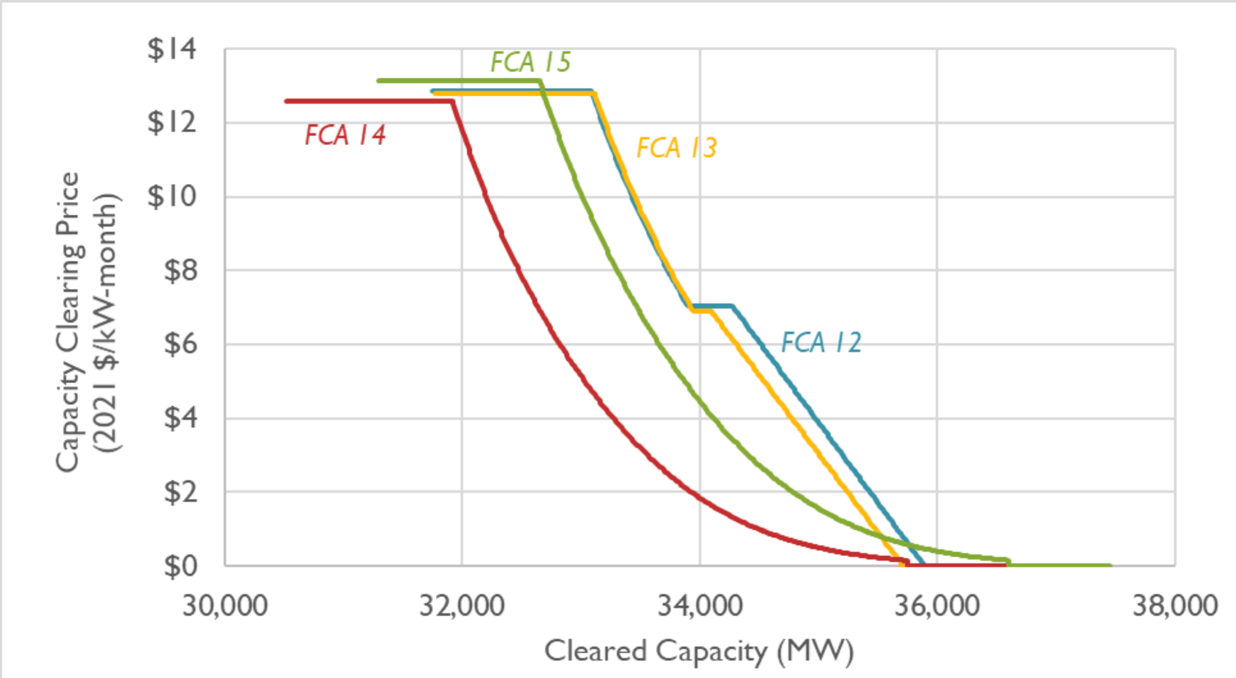
Historical demand curves

ISO New England has used the administrative demand curve for several years to provide greater stability in capacity prices and acquire additional resources when prices are low. Starting with FCA 14, the demand curve has been a smooth curve, shaped to mimic the change in loss-of-load expectation. The demand curve is scaled so that the capacity price equals ISO New England's estimate of cost of new entry (CONE) at the net installed capacity requirement (Net ICR).

Figure 31 shows the FCA 12 and FCA 13 demand curves, the last two auctions featuring a stepped demand curves, and the two more recent auctions that have used fully smoothed demand curves. Note that the curve for FCA 14 moved considerably lower relative to FCA 13, while the curve for FCA 15 moved back up.

To model FCA 16 and future years, we rely on the demand curve for FCA 15, shifted according to projected changes in demand in each counterfactual.

Figure 31. Recent FCA demand curves



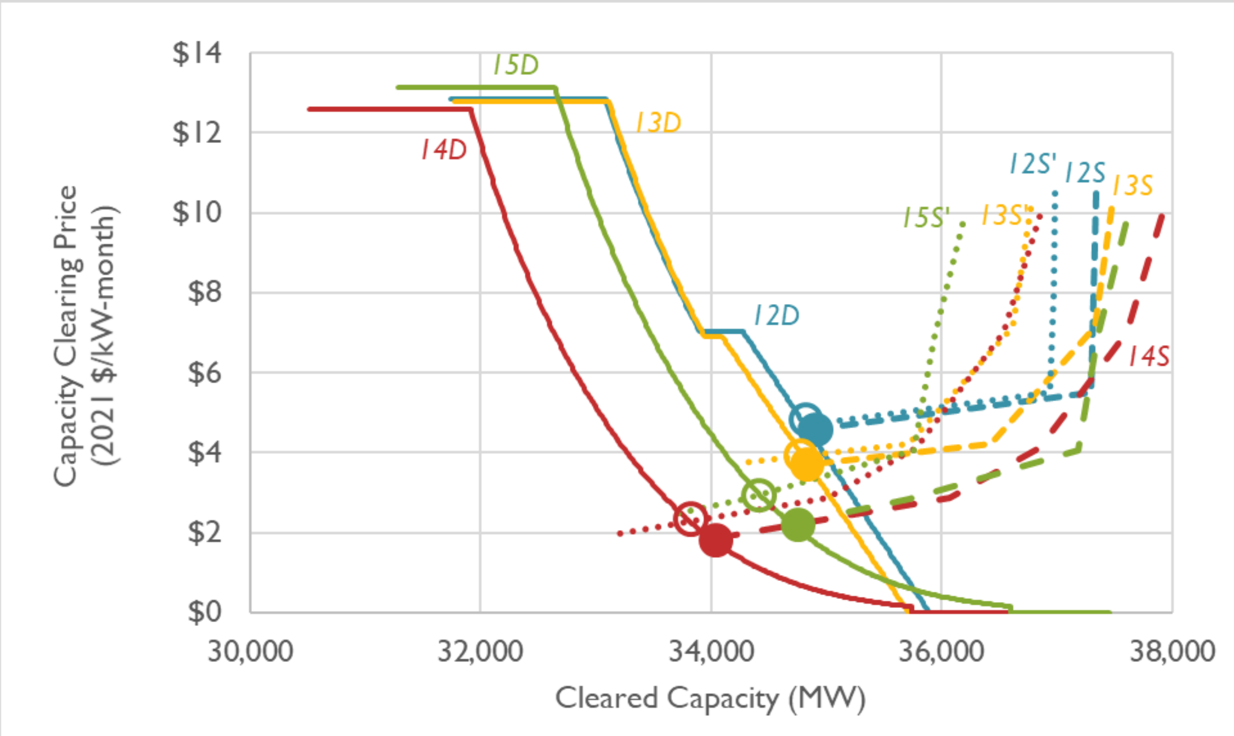
Note: All prices have been converted into 2021 dollars.

Historical capacity price results

Figure 32 shows the result of matching the demand and supply curves for FCA 12 through FCA 15. The figure shows each FCA represented by a distinct color. The figure then is further differentiated with:

- A solid line representing the demand curve for each FCA
- A dashed line representing the supply curve for each FCA
- A dotted line for the supply curve for Counterfactual #1 that excludes the post-2020 energy efficiency for each FCA
- A solid circle that shows the actual market clearing price for each auction
- An empty circle that indicates what the clearing price would have been if not for energy efficiency that was installed in 2021 and later years

Figure 32. Market clearing capacity prices for FCA 12 through FCA 15



Notes: Solid lines marked "D" are demand curves, dashed lines marked "S" are actual supply curves, and dotted lines marked "S'" are supply curves absent post-2020 energy efficiency. Solid circles denote the clearing price under actual conditions while empty circles denote what the clearing price would have been but for post-2020 energy efficiency. Only results for rest-of-pool are shown.

The exact clearing price in each auction depends on the size of the marginal unit, since ISO New England accepts entire units rather than individual megawatts. Hence, the actual FCA supply curve does not quite intersect with the demand curve, especially for FCA 12 and FCA 14; these clearing prices must have been set by large units. Table 37 summarizes the clearing prices for the actual and hypothetical "without post-2020 EE" cases described in Figure 32.

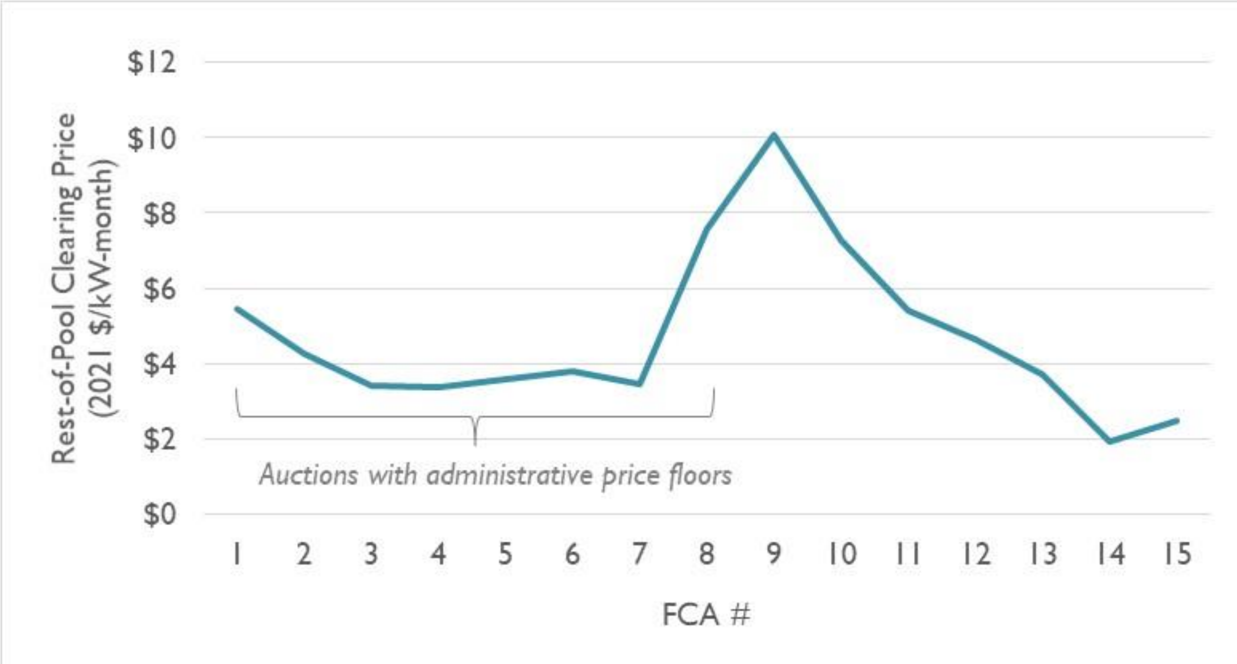
Table 37. Capacity prices for recent and pending FCAs (2021 $ per kW-month)

Commitment Period (June to May)	**FCA**	**Actual Clearing Price** *2021 $*	**Actual Clearing Price Without post-2020 EE** *2021 $*
2021/2022	12	$4.63	$4.77
2022/2023	13	$3.73	$3.96
2023/2024	14	$1.92	$2.47
2024/2025	15	$2.46	$3.29

Note: Rest-of-pool prices only.

As a point of reference, Figure 33 illustrates the actual clearing prices since the start of the FCM. The average rest-of-pool clearing prices over the four most recent auctions is $3.19 kW-month.

Figure 33. Forward capacity auction clearing prices for all past auctions (rest-of-pool prices only)



Note: All prices have been converted into 2021 dollars.

Projecting future capacity prices

For each subsequent auction after FCA 15, we estimate both the demand curve and the supply curve, using the steps described above. The demand curve shifts to the right as the forecasted peak increases. The supply curve shifts left or right, depending on the extent of resource retirements and additions.[150] The intersection of these two curves indicates the capacity price.

Table 38 depicts the estimated peak demand under each counterfactual in the future years where prices are simulated (as opposed to 2021 through 2024, where capacity prices are based on actual observations). We calculated peak demand based on the aggregate hourly peak load from the drivers described in Section 4.3: *New England system demand*. Peak demand for Counterfactuals #1, #3, and #4 are relatively similar due to the similarity of their underlying assumptions. Peak demand for Counterfactual #2 is substantially lower, as this counterfactual incorporates incremental energy efficiency after 2020.

[150] The supply curve will also change with the economics of continued operation of resources, the operators' bidding strategies, the availability of imports, ISO New England's rules for resource eligibility, and other factors. We have not estimated those changes, which will be driven by factors that are difficult to forecast.

Table 38. Projected cumulative change in demand (GW), relative to FCA 15

		Counterfactual #1	Counterfactual #2	Counterfactual #3	Counterfactual #4
FCA 16	2025	0.5	0.1	0.5	0.5
FCA 17	2026	0.8	0.1	0.8	0.8
FCA 18	2027	1.2	0.2	1.2	1.2
FCA 19	2028	1.6	0.2	1.6	1.6
FCA 20	2029	2.1	0.4	2.1	2.1
FCA 21	2030	2.5	0.5	2.5	2.5
FCA 22	2031	2.9	0.6	2.9	2.9
FCA 23	2032	3.3	0.8	3.3	3.3
FCA 24	2033	3.9	1.0	3.9	3.9
FCA 25	2034	4.4	1.3	4.4	4.4
FCA 26	2035	4.9	1.5	4.9	4.9

Table 39 depicts the available supply under each counterfactual in the future years where prices are simulated (as opposed to 2021–2024, where capacity prices are based on actual observations). Projected supply is based on the impacts from the drivers described in Chapter 4. *Common Electric Assumptions*, Chapter 7. *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies*, and the dynamics of the CASPR auction described below in the subsection titled *ISO New England's Competitive Auctions with Sponsored Resources initiative*. The supply depicted here is the net cumulative supply relative to FCA 15, after accounting for conventional plant retirements and additions, as well as CASPR-eligible plant additions.

Projected supply for Counterfactuals #1, #3, and #4 are relatively similar due to the similarity of their underlying assumptions. Projected supply for Counterfactual #2 is substantially lower, as this Counterfactual incorporates incremental energy efficiency after 2020. See Chapter 6. *Avoided Energy Costs* for more discussion on these results.

Table 39. Projected cumulative change in supply (GW), relative to FCA 15

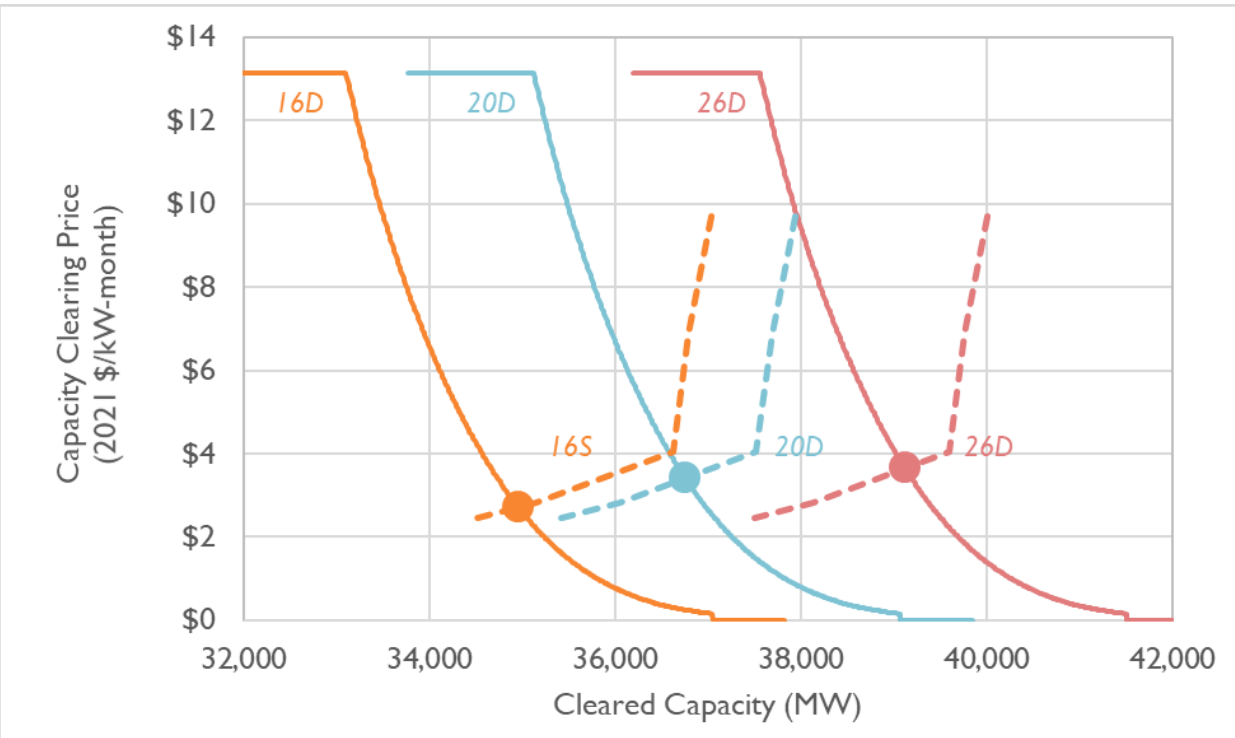
		Counterfactual #1	Counterfactual #2	Counterfactual #3	Counterfactual #4
FCA 16	2025	-0.6	-0.9	-0.3	-0.3
FCA 17	2026	-0.5	-0.8	-0.2	-0.2
FCA 18	2027	-0.4	-1.8	-1.0	-0.9
FCA 19	2028	-0.4	-1.7	-0.9	-0.9
FCA 20	2029	-0.3	-1.7	-0.9	-0.8
FCA 21	2030	0.3	-2.1	-0.5	-0.4
FCA 22	2031	0.4	-2.1	0.2	0.3
FCA 23	2032	0.4	-2.0	0.3	0.3
FCA 24	2033	1.1	-2.0	0.9	1.0
FCA 25	2034	1.1	-1.9	1.0	1.0
FCA 26	2035	2.4	-1.3	2.3	2.3

As described above, our simplified capacity market model does not estimate geographic price separation in any years after FCA 15. We observed relatively minimal price separation in FCA 15, but we do assume no price separation in future years. Although it is possible that prices separation could occur in some future years, there is much uncertainty in terms of when this separation could occur, where it could occur, what level of price spread occurs, and how long the effect lasts. Thus, for purposes of simplicity, we assume a single regional clearing price in all modeled years.

Results

As described above, for each year and each counterfactual, MW differences in demand (relative to FCA 15) are added to or subtracted from the FCA 15 demand curve to create a new future demand curve. A similar operation is performed for the FCA 15 supply curve using the changes in supply. Figure 34 illustrates the resulting market clearing prices in Counterfactual #1 for a selection of years. In this counterfactual, capacity prices in FCA 16 and later range from $2.72 per kW-month to $4.67 per kW-month in 2021 dollars. The market-clearing prices in the out-years are principally determined by whether the balance of the qualified and cleared capacity additions, primarily from battery storage and offshore wind, and retirements of thermal generation (fossil steam, combustion turbines, some older combined-cycle units, and some biomass), and how the resulting supply compares to the change in demand.

Figure 34. Forecast of selected FCA prices in Counterfactual #1 (2021 $ per kW-month) in rest-of-pool region



Notes: Solid lines marked "D" are demand curves while dotted lines marked "S" are supply curves. Empty circles denote estimated clearing prices. Several supply curves are not marked on this figure, but lie in between 16S and 26S. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

These capacity prices, projected for 2025 and later years, are then appended to actual capacity prices for 2021–2024 (in the case of Counterfactual #2) and capacity price projections for these same years but for the impact of post-2020 energy efficiency (in the case of Counterfactuals #1, #3, and #4). Table 40 and Figure 35 compare the complete capacity price projections for each counterfactual. In general, Counterfactual #2 has lower capacity prices due to a lower projection of load, while Counterfactual #1, Counterfactual #3, and Counterfactual #4 are relatively similar due to similar projections of annual loads. Small year-on-year differences are due to changes in load, new resources coming online, and other resources retiring. These are the avoided capacity costs used for cleared resources.

Compared to AESC 2018, the AESC 2021 capacity prices are about half as large on a 15-year levelized basis. Prices tend to be lower and remain low because the amount of demand and supply resources modeled in future years is expected to produce clearing prices that occur in a relatively low and shallow part of both the supply and demand curves.[151]

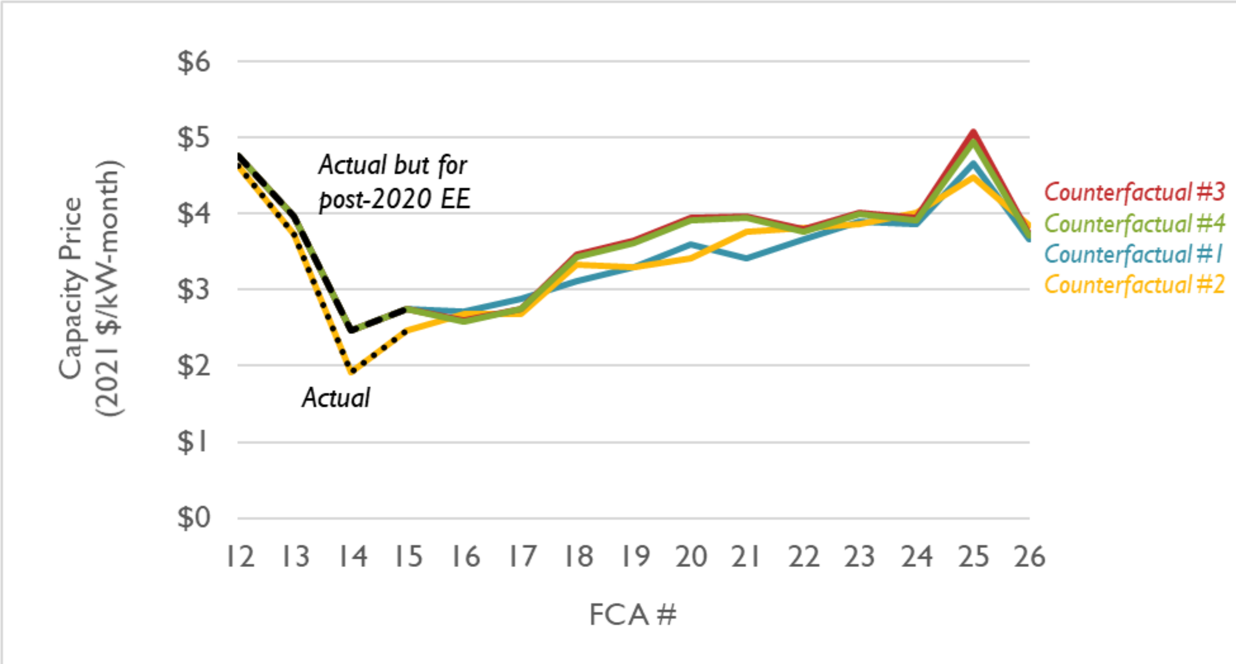
Table 40. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	Actual	Actual but for post-2020 EE	AESC 2021 Counter-factual #1	AESC 2021 Counter-factual #2	AESC 2021 Counter-factual #3	AESC 2021 Counter-factual #4	AESC 2018
2021/2022	12	$4.63	$4.77	$4.77	$4.63	$4.77	$4.77	$4.99
2022/2023	13	$3.73	$3.96	$3.96	$3.73	$3.96	$3.96	$5.10
2023/2024	14	$1.92	$2.47	$2.47	$1.92	$2.47	$2.47	$5.21
2024/2025	15	$2.46	$2.75	$2.75	$2.46	$2.75	$2.75	$5.50
2025/2026	16			$2.72	$2.69	$2.59	$2.59	$5.95
2026/2027	17			$2.88	$2.69	$2.75	$2.75	$6.46
2027/2028	18			$3.11	$3.33	$3.46	$3.43	$6.95
2028/2029	19			$3.30	$3.30	$3.65	$3.62	$7.45
2029/2030	20			$3.59	$3.41	$3.94	$3.92	$7.95
2030/2031	21			$3.42	$3.77	$3.97	$3.94	$6.95
2031/2032	22			$3.67	$3.81	$3.79	$3.77	$7.45
2032/2033	23			$3.90	$3.86	$4.02	$3.99	$7.95
2033/2034	24			$3.86	$4.02	$3.95	$3.92	$6.95
2034/2035	25			$4.67	$4.47	$5.09	$4.95	$7.45
2035/2036	26			$3.66	$3.86	$3.73	$3.71	$7.95
15-year levelized cost				**$3.51**	**$3.45**	**$3.65**	**$3.63**	**$6.63**
Percent difference				**-47%**	**-48%**	**-45%**	**-45%**	

Notes: Levelization periods are 2021/2022 to 2035/2036 for AESC 2021 2018/2019 to 2032/2033 for AESC 2018. Real discount rate is 0.81 percent for AESC 2021 and 1.34 percent for AESC 2018. Values for "Actual" and "Actual but for post-2020 EE" are calculated based on rest-of-pool. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

[151] The shapes of both of these curves are determined by data published by ISO New England, either directly through a publication by ISO New England (in the case of the FCA 15 demand curve) or indirectly via auction results (in the case of the FCA 15 supply curve).

Figure 35. Comparison of capacity prices in AESC 2021 across different counterfactuals



Note: Values for "Actual" and "Actual but for post-2020 EE" are shown based on rest-of-pool. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

5.2. Uncleared capacity calculations

Any load reduction that clears provides avoided capacity costs in the year that the resource participates in the capacity auction. For example, if a program administrator has bid 1 MW into FCA 15 and expects to deliver that 1 MW starting in the summer of 2024 (the beginning of the FCA 15 commitment period), that benefit will receive the full avoided capacity cost benefit starting in 2024. Likewise, if this measure is re-bid into each subsequent auction for the duration of its life, it will receive an avoided capacity cost equal to the market clearing price for all future years.

But not all resources are bid into the FCA. 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 some (or only a portion) of the anticipated capacity into the FCA.[152]

This remaining capacity is known as "uncleared" capacity. Unlike cleared capacity, the benefit associated with this resource is not simply the capacity price multiplied by the resource's capacity. Instead,

[152] As long as it is "qualified" to participate in auctions (per ISO New England's definition and rules), the uncleared portion of the resource may be later bid into monthly annual reconciliation auctions (MRA), annual reconciliation auctions (ARA), as well as for the FCAs for later commitment periods. In general, ARA prices are lower than FCA prices; for the ARAs completed for the commitment periods ending in 2018 to 2021, the first ARA averaged about 76 percent of the FCA price, the second ARA averaged 37 percent, and the third ARA averaged 31 percent.

uncleared capacity utilizes a “phase-in” and “phase-out” schedule that approximates how the impacts of these resources are indirectly captured in the development of inputs to ISO New England’s FCM.

Phase-in

Each year, ISO New England generates a demand forecast using a complex regression analysis of load, weather, and a time trend over 15 years of historical summer (primarily July and August) daily peak loads. As load reductions from uncleared efficiency programs appear in the model’s data, forecasts of capacity requirements (i.e., load) are reduced.[153] Because each annual capacity auction is performed three years in advance of a commitment period, and because there is a lag in terms of when changes to load appear in the load forecast used for a capacity auction, we assume that benefits from uncleared capacity do not start until 5 years after their installation date. Table 41 describes a hypothetical timeline where a measure is installed in 2019, but does not produce an impact on the capacity market for another five years.

Table 41. Illustration of when uncleared capacity begins to have an effect

Year	Event
2019	Measure is installed and begins to reduce load.
2020	ISO New England publishes a load forecast that is partially impacted by the load reductions installed in the previous year.
2021	An annual capacity auction occurs (effective three years from now in 2024). The demand curve in this auction is based on the load forecast made in the previous year.
2022	-
2023	-
2024	The year the prices from the capacity auction take place. The uncleared measure now begins to have an impact.

Phase-out

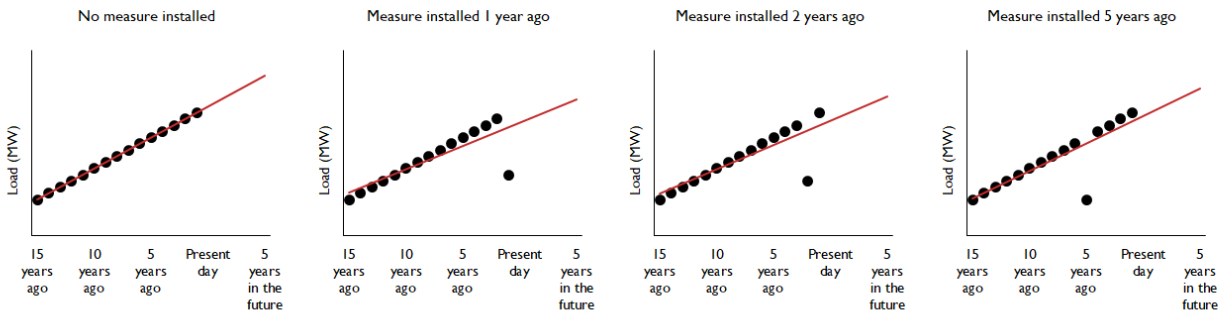
However, once impacts begin (in year N+5), they are discounted to some degree. The phase-in of these impacts is non-linear, depending on the duration of load reductions and when in the 15-year dataset the reductions occur. The following paragraphs illustrate two examples of this phenomenon.

Figure 36 illustrates how a measure with a one-year measure life may impact the load forecast used in the FCM In each panel, the black dots illustrate historical load data, with the right-most dot representing data from the most recent historical year. The red line is a simple best-fit linear regression continuing for several years into the future. The first panel shows a base case with 15 years of data and no reduction in load. The second panel shows the effect of a one-year load reduction on a linear regression when that load reduction occurs in the most recent historical year. The third panel shows an alternate situation, where the one-year load reduction occurred two years in the past. The final panel shows a situation

[153] 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.

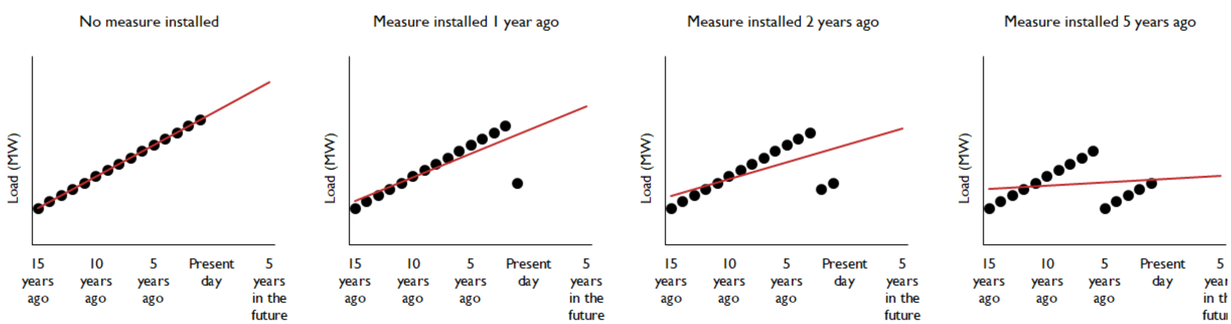
where the one-year load reduction has occurred five years in the past. These examples show that the single-year load reduction has the largest impact on the forecast when it is at the end of the data, in the most recent past year. When the reduction has aged, the impact on the forecast is more modest. This is because the critical point is more towards the center of the 15-year time series rather than on the edge.

Figure 36. Illustrative impacts of a single-year load reduction on the peak forecast



In a second example, Figure 37 depicts the impact of a load reduction with a five-year measure life. This measure is illustrated at having been installed at various times: not at all in the first panel, one year ago in the second panel, two years ago in the third panel, and five years ago in the final panel. The program's effect on the load forecast (the red line) increases with multiple years of operation. The longer a measure is in effect, the flatter the resulting trend line.

Figure 37. Illustrative impacts of a five-year load reduction on the peak forecast



Load forecast effect (LFE) schedule

The above observations lead us to a set of conclusions:

In reality, we would expect the capacity market to respond to the cumulative effect of each program on the load forecast (and hence the demand curve used in the auction). Because of the complexity associated with these forecast reductions, we approximate the incremental phase-in schedule using simplified blocks (see Table 42). We assume that the first year a one-year measure produces an impact on the load forecast, the uncleared capacity benefit is scaled by 30 percent. In the following three years, the benefit is scaled by 20 percent. In the fourth year, the benefit is scaled by 10 percent, and by the fifth year, we assume the benefit is erased completely.

Table 42. LFE schedule for a measure with a one-year lifetime installed in 2021

	Percent of uncleared capacity impact in place
2021	0%
2022	0%
2023	0%
2024	0%
2025	0%
2026	30%
2027	20%
2028	20%
2029	20%
2030	10%
2031	0%
2032	0%
2033	0%
2034	0%
2035	0%

However, because these effects are assumed to be driven by the cumulative impact of a measure, if a measure produces savings for multiple years, it will have a greater and more sustained price effect. Table 43 shows the schedule assumed for measures with lifetimes varying from one to ten years.[154] 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.[155] For example, in 2027, the assumed effect is equal to 50 percent, or the sum of the 2026 impact from a one-year program and the 2027 impact from a one-year program.

[154] See the *AESC 2021 User Interface* for a detailed schedule of uncleared capacity DRIPE effects for measures lasting one through 35 years. We note that AESC 2018 described there being two separate LFE schedules for long-duration and short-duration measures. This is because for measure lives 10 years or greater, the LFE schedule is effectively same for the first 15 years of a measure lifetime (see the last column in Table 43). In the *AESC 2021 User Interface*, we explicitly calculate the uncleared resource effects for 35 different measure lives for the entire study period (2021 through 2055) and thus no longer need to make this simplifying assumption.

[155] 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.

Table 43. LFE schedule for uncleared capacity value for measures with L lifetimes installed in 2021

	L=1	L=2	L=3	L=4	L=5	L=6	L=7	L=8	L=9	L=10
2021	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2022	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2023	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2026	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
2027	20%	50%	50%	50%	50%	50%	50%	50%	50%	50%
2028	20%	40%	70%	70%	70%	70%	70%	70%	70%	70%
2029	20%	40%	60%	90%	90%	90%	90%	90%	90%	90%
2030	10%	30%	50%	70%	100%	100%	100%	100%	100%	100%
2031	0%	10%	30%	50%	70%	100%	100%	100%	100%	100%
2032	0%	0%	10%	30%	50%	70%	100%	100%	100%	100%
2033	0%	0%	0%	10%	30%	50%	70%	100%	100%	100%
2034	0%	0%	0%	0%	10%	30%	50%	70%	100%	100%
2035	0%	0%	0%	0%	0%	10%	30%	50%	70%	100%

Note: Measures installed in subsequent years utilize the same schedule, but shifted by an appropriate number of years (e.g., a measure installed in year 2022 would see effects beginning in year 2027). Note that effects for measures with measure lives of six years or greater continue to phase out after 2035. Because of this, the AESC 2021 User Interface calculates these effects through 2050 for each individual year, rather than extrapolating values.

Reserve margin requirements

Each year ISO New England calculates a net installed capacity requirement (Net ICR) that represents the target amount of capacity to be purchased in the Forward Capacity Auction in order to plan for a system that meets the accepted standard for resource adequacy. While the actual amount of capacity procured depends upon many factors, the percentage by which the Net ICR exceeds the projected system peak is the planning reserve margin. Over the last four auctions, the reserve margin has averaged 14.2 percent (see Table 44). We assume this average value persists from 2025 through 2035 for all counterfactuals. AESC 2021 estimates reserve margins independently of clearing prices. This is because the planning reserve margins are based upon the target amount to be procured, and actual capacity purchased is often much higher as incumbent generation owners are willing to accept very low capacity payments dictated by a downward sloping demand curve.

Table 44. Calculated reserve margins

Summer	FCA #	Calculated reserve margin
2021	12	15%
2022	13	16%
2023	14	13%
2024	15	14%
Average	**-**	**14%**

The reserve margin is particularly relevant to the calculation of uncleared capacity benefits. Uncleared measures are effectively “counted” on the demand side of the capacity auction (i.e., within the load forecast). In contrast, cleared measures are effectively treated the same as conventional power plants (i.e., supply), and through the auction effectively require the purchase of some extra amount of capacity to act as a reserve margin. As a result, we increase the uncleared capacity benefit by a value equal to one plus the reserve margin.

Calculating the benefit from uncleared capacity

Finally, to calculate the benefit from uncleared capacity in any particular year, we calculate the product of:

- The capacity price (e.g., the values in Table 40)
- The effect schedule that matches the measure's lifetime (e.g., the values in Table 43)
- One plus the reserve margin (e.g., the values in Table 44)

Table 45 describes the uncleared capacity benefit in Counterfactual #1. This table describes benefits for measures installed in 2021, with measure lives ranging from one to ten years.

Table 45. Uncleared capacity value for measures with L lifetimes installed in 2021 in Counterfactual #1 in rest-of-pool region

	L=1	L=2	L=3	L=4	L=5	L=6	L=7	L=8	L=9	L=10
2021	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2022	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2023	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2024	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2025	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2026	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67	$11.67
2027	$8.47	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17	$21.17
2028	$9.02	$18.05	$31.58	$31.58	$31.58	$31.58	$31.58	$31.58	$31.58	$31.58
2029	$9.83	$19.66	$29.49	$44.23	$44.23	$44.23	$44.23	$44.23	$44.23	$44.23
2030	$4.68	$14.03	$23.39	$32.74	$46.77	$46.77	$46.77	$46.77	$46.77	$46.77
2031	$0.00	$5.02	$15.07	$25.12	$35.17	$50.24	$50.24	$50.24	$50.24	$50.24
2032	$0.00	$0.00	$5.34	$16.01	$26.69	$37.36	$53.38	$53.38	$53.38	$53.38
2033	$0.00	$0.00	$0.00	$5.28	$15.85	$26.42	$36.98	$52.83	$52.83	$52.83
2034	$0.00	$0.00	$0.00	$0.00	$6.39	$19.17	$31.95	$44.73	$63.90	$63.90
2035	$0.00	$0.00	$0.00	$0.00	$0.00	$5.01	$15.02	$25.03	$35.04	$50.06
15-year levelized	**$2.92**	**$5.96**	**$9.12**	**$12.39**	**$15.74**	**$19.21**	**$22.36**	**$24.82**	**$26.66**	**$27.61**

Note: Note that effects for measures with measure lives of six years or greater continue to phase out after 2035. Because of this, the AESC 2021 User Interface (tab "Appdx J") calculates these effects through 2050 for each individual year, rather than extrapolating values. See the AESC 2021 User Interface for benefits in other counterfactuals, other regions, and benefits for measures with longer lifetimes.

Important caveats for applying uncleared capacity values

Uncleared capacity is different than many other avoided cost categories. Because uncleared capacity describes an effect that fades out over time due to the market's responses to that effect, users should sum avoided costs over the entire study period, regardless of any one measure's lifetime. For example, the avoided costs of a 1 MW measured installed in 2021 would be equal to the sum of the values from

2021 through 2055, regardless of whether that measure had a 1-year measure life or a 30-year measure life.[156]

Uncleared resources affect the load forecast only to the degree that these resources provide load reductions on the hours used in the load forecast regression. Some resources—such as demand response resources—may be active only on one or some of the hours used in the load forecast. As a result, these resources would provide a diminished uncleared capacity benefit. We recommend that program administrators apply a scaling factor to the benefits detailed in Table 45 to account for this effect. See Appendix K: *Scaling Factor for Uncleared Resources* for more information on how this scaling factor is calculated and how it can be applied.

5.3. Other considerations

The following sections provide greater detail on other aspects of the capacity market assessed in AESC 2021.

ISO New England's Competitive Auctions with Sponsored Resources initiative

This section describes ISO New England's CASPR rule and how it is modeled in AESC 2021. This modeling is integral to the calculation of projected capacity supply, described above.

ISO New England has run two capacity auctions using a new method to allow some new resources sponsored by state policy to acquire capacity supply obligations without swamping the FCM. ISO New England's CASPR rule does not allow a new resource to bid into the capacity auctions at a price below its estimated cost, net of expected revenues from the ISO energy, capacity, and ancillary markets, plus revenues from RECs that are available to resources from a broad geographic and technology range. Any additional targeted revenues cannot be used to justify a lower bid price. This may include revenue from Massachusetts's SMART program for distributed solar; 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); or state-mandated contracts for purchases from Canada, offshore wind, or other renewables. As a result of CASPR, sponsored resources will often be unable to bid low enough to clear in the main auction, especially at the low prices observed in recent FCAs.

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 runs 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 $4 per kW-month, a cleared generator might offer to pay up to $3 per kW-month to get out of a capacity supply obligation. The substitution auction may clear at $1 per kW-

[156] We note that this is the same approach used for summing avoided costs for uncleared capacity and uncleared capacity DRIPE, but no other avoided cost categories.

month, in which case the retiring generator will be paid $4–$1 = $3 per 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 then give up its transmission interconnection rights and permanently retire from all ISO markets.[157] 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 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 future market prices indefinitely.

One effect of the CASPR rules will be to create incentives for marginally viable existing generators to bid in the FCA with the intention of selling the capacity supply obligation in the substitution auction. As a result, most existing capacity supply obligations from transmission-connected generators may never retire, since they can be profitably transferred to sponsored resources.

Through FCA 14, sponsored renewables were able to qualify under a temporary exception to the minimum bid limits, known as the Renewable Technology Rule. The exception was removed in FCA 15, after which new sponsored resources with need to acquire capacity obligations in the CASPR secondary auction.

We model CASPR by treating CASPR-eligible resources (such as wind and solar) separately within our capacity model. We first assess the incremental year-on-year firm capacity of these resources, then determine whether or not there is sufficient retiring capacity in that same year. If yes, capacity from these resources is deemed eligible for the main capacity market and is added to the overall calculation of supply.

Other capacity-related avoided costs

In addition to the locational marginal energy prices and capacity prices, ISO New England's 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

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

- 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*.[158] For 2019, ISO New England's estimates of costs to load (a load with 100 percent load factor) for most zones comprised energy (about 70 percent of the total) and capacity costs (about 26 percent) as well as a few percent for all of the NCPC, reserves, and regulation put together. These ratios will change over time, for example, as capacity prices fall.

None of the components listed below 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 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

[158] ISO New England. Last accessed March 11, 2021. "Energy, load, and Demand Reports." *EPA.gov.* Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/mthly-whl-load-cost-rpt.

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 (NYISO, Hydro Québec, 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 FCM.

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 2021 and AESC 2018.[159] On a levelized basis, the 15-year AESC 2021 annual all-hours price for Counterfactual #1 is $41 per MWh, compared to the equivalent value of $51 per MWh from AESC 2018. This represents a reduction of 20 percent. For Counterfactual #2, the 15-year AESC 2021 annual all-hours price is $38 per MWh, representing a reduction of 26 percent relative to the value from AESC 2018. Counterfactual #3 and #4 both feature 15-year AESC 2021 annual all-hours prices of $41 per MWh, a 19 percent reduction relative to AESC 2018.[160] The decrease in energy prices observed in AESC 2021 is primarily due to a lower estimate of wholesale natural gas prices in New England and a lower estimate of RGGI prices.

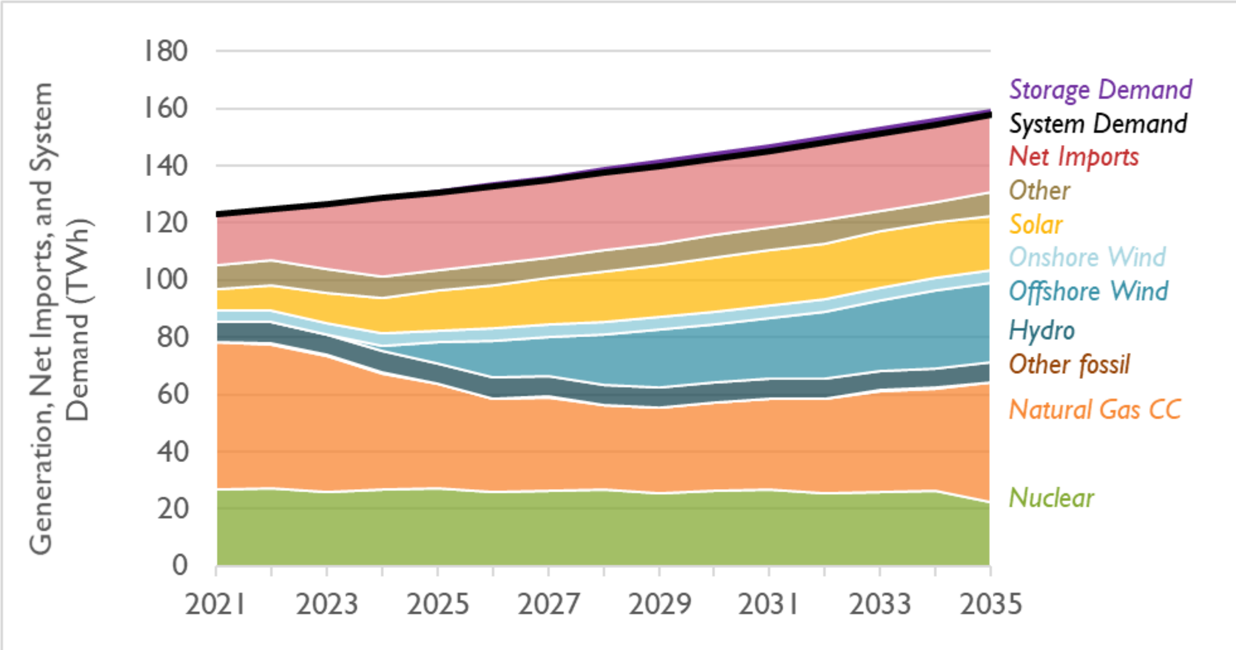
6.1. Forecast of energy and energy prices

Figure 38 presents the projected level of New England electric system energy from 2021 to 2035. These energy levels are estimated by the EnCompass model given the capacities specified in Figure 39, fuel prices, availability factors, heat rates, and other unit attributes. Figure 38 assumes a future in which no new energy efficiency is added in 2021 or later years, and other assumptions are consistent with Counterfactual #1. 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.

[159] This WCMA price is intended to represent the ISO New England Control Area price, which is within this zone.

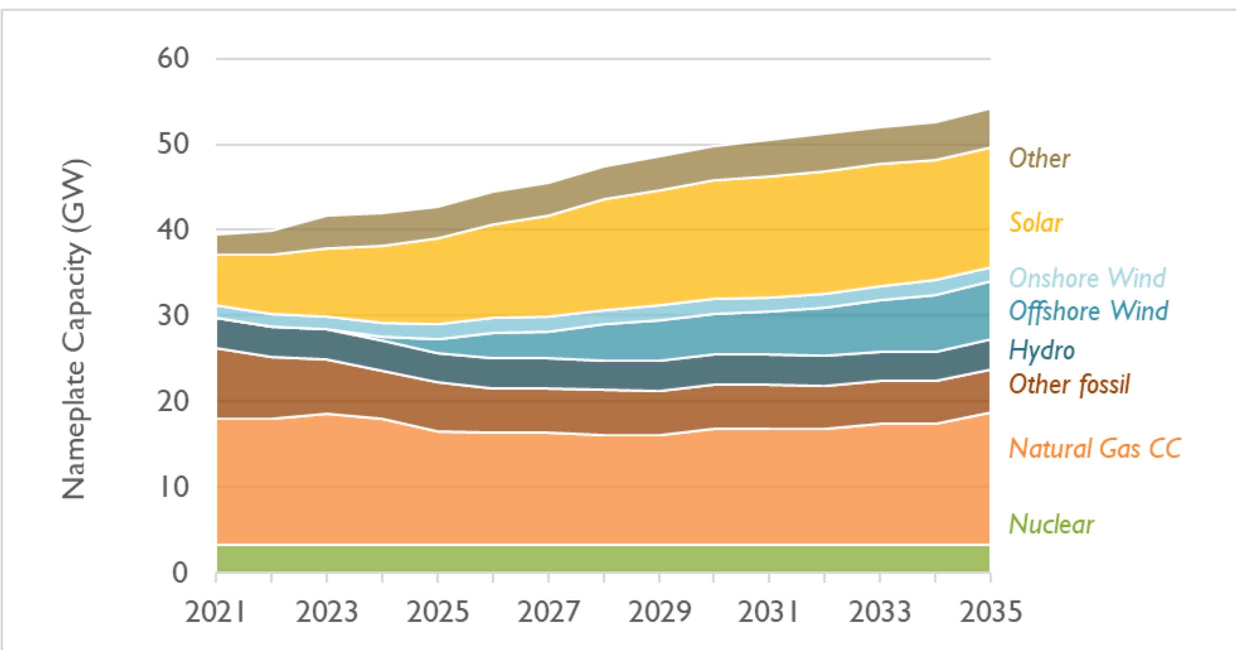
[160] The difference in percentage change relative to Counterfactual #1 is a result of rounding.

Figure 38. AESC 2021 New England-wide generation, imports, and system demand in Counterfactual #1



Notes: "Other Fossil" contains generation from steam turbines (including coal), combustion turbines, fuel cells, and other miscellaneous fossil fuel-fired power plants. "Other" contains generation from energy storage, demand response, municipal solid waste, landfill gas, and other miscellaneous fuel types.

Figure 39. New England-wide capacity modeled in EnCompass in Counterfactual #1



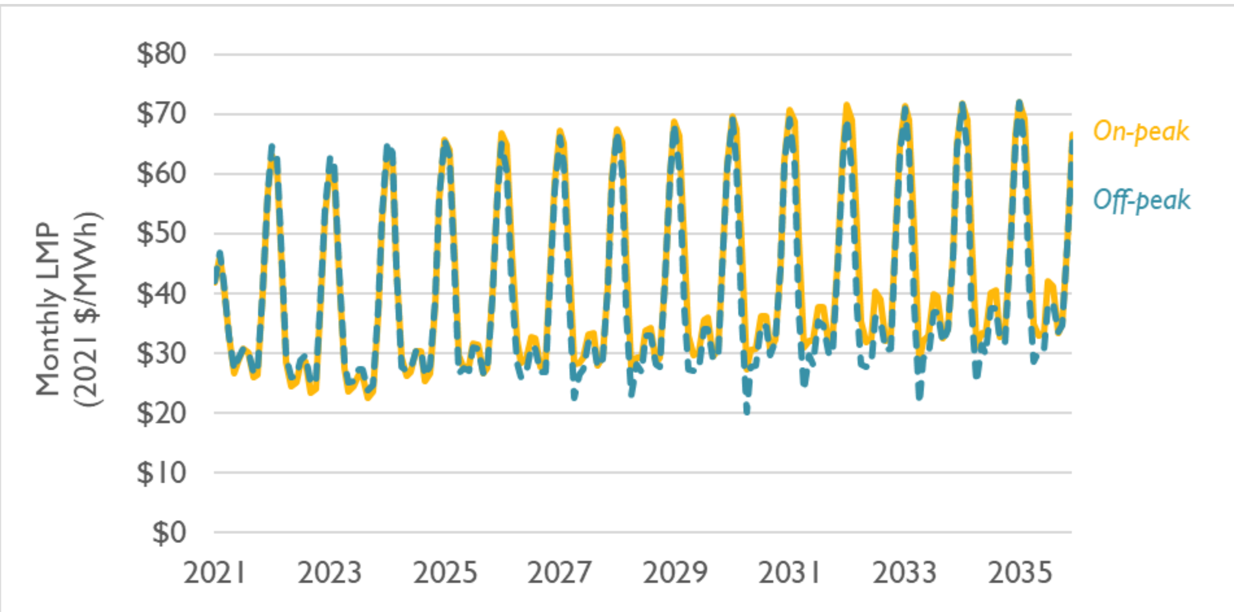
Notes: "Other Fossil" contains capacity associated with steam turbines (including coal), combustion turbines, fuel cells, and other miscellaneous fossil fuel-fired power plants. "Other" contains capacity associated with energy storage, demand response, municipal solid waste, landfill gas, and other miscellaneous fuel types. Capacity is included in the above chart in a given year if a resource is existing on January 1 of that year.

Forecast of wholesale energy prices

In addition to modeling the generation shown in Figure 39, the EnCompass model also produces wholesale energy prices (see Figure 40 and Table 46).[161] 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. 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 from Canada in the early 2020s, large quantities of offshore wind in the mid to late 2020s, a flattening of assumed Henry Hub prices in real-dollar terms through the 2030s, and lower RGGI prices.[162]

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

Figure 40. AESC 2021 wholesale energy price projection for WCMA in Counterfactual #1



Note: As elsewhere in this report, in this figure, on-peak and off-peak are defined according to ISO New England's definitions, and may not match popular conceptions of on-peak or off-peak. See Appendix B: Detailed Electric Outputs for more information on this topic.

161 Note that all summarized energy prices are calculated using a load-weighted average.

162 Note that modeled energy prices described here do not include impacts from ISO New England's proposed Energy Security Initiative (ESI) which was rejected by FERC in October 2020.

Table 46. AESC 2021 wholesale energy price projection for WCMA region in Counterfactual #1 (2021 $ per MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
2021	$36.05	$42.85	$36.72	$31.93	$26.26
2022	$37.61	$45.03	$41.65	$28.79	$25.30
2023	$36.61	$43.18	$42.03	$26.19	$25.06
2024	$39.05	$45.30	$44.19	$29.39	$27.84
2025	$39.56	$45.69	$44.61	$30.23	$28.35
2026	$39.94	$46.69	$44.26	$31.50	$27.97
2027	$40.12	$47.43	$43.35	$32.90	$27.77
2028	$40.49	$45.79	$45.45	$31.62	$30.45
2029	$41.80	$46.95	$47.18	$32.77	$31.46
2030	$41.99	$46.97	$47.04	$33.46	$31.98
2031	$42.86	$47.91	$47.92	$34.52	$32.47
2032	$43.74	$50.30	$47.22	$37.19	$31.48
2033	$44.04	$49.72	$47.97	$36.93	$33.15
2034	$44.73	$49.65	$49.59	$36.57	$34.69
2035	$45.57	$50.49	$50.43	$37.52	$35.35

Comparison to AESC 2018

Table 47 shows a comparison between AESC 2018 and AESC 2021 for the 15-year levelized costs for the WCMA reporting region. Prices are shown for all hours, and for the four periods analyzed in previous AESC studies. On an annual average basis, the Counterfactual #1 15-year levelized prices in the AESC 2021 Study are 20 percent lower than the prices modeled in the AESC 2018 Study, while the Counterfactual #2 15-year levelized prices are 26 percent lower. Counterfactual #3 and #4 both show levelized prices that are 19 percent lower than the prices modeled in the AESC 2018 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 renewable policies in several states), and the addition of a new transmission line from Canada.[163] This decrease is larger than the change in avoided energy costs observed between the AESC 2015 Study and the AESC 2018 Study.

In particular, AESC 2021 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 summer 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. These are the same factors that drove the change in energy prices from AESC 2015 and AESC 2018. Meanwhile, the ratio of winter peak prices to annual average prices are largely unchanged, relative to AESC 2018.

[163] 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.

This is due to largely consistent assumptions on winter gas costs (relative to annual averages) and similar load shapes.

Among the counterfactuals, prices are generally similar due to the relatively flat supply curve for energy in New England. In other words, the region has a large number of relatively new, similar, natural gas-fired combined cycle units that are frequently marginal in any future year, in any future counterfactual. That said, Counterfactual #2 does feature lower prices compared to the other two counterfactuals due to lower system loads and lower peak demand.[164]

Table 47. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2018	$51.17	$58.66	$54.17	$45.22	$38.69
AESC 2021 Counterfactual 1	$40.85	$46.86	$45.20	$32.67	$29.86
AESC 2021 Counterfactual 2	$37.79	$42.98	$41.66	$30.87	$27.95
AESC 2021 Counterfactual 3	$41.34	$47.43	$45.63	$33.28	$29.93
AESC 2021 Counterfactual 4	$41.29	$47.40	$45.62	$33.17	$29.87
% Change: Counterfactual 1	-20%	-20%	-17%	-28%	-23%
% Change: Counterfactual 2	-26%	-27%	-23%	-32%	-28%
% Change: Counterfactual 3	-19%	-19%	-16%	-26%	-23%
% Change: Counterfactual 4	-19%	-19%	-16%	-27%	-23%

Notes: All prices have been converted to 2021 $ per MWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2021. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. AESC 2018 values are from AESC 2018 Chapter 5 and the AESC 2021 User Interface.

Table 48 compares 15-year levelized costs between AESC 2018 and AESC 2021 for each of the six New England states. These values incorporate the relevant costs of RPS compliance, as well as the impact of wholesale risk premiums. Avoided energy costs for each reporting region are detailed in Appendix B: *Detailed Electric Outputs*.

[164] These results are consistent with the "With EE" sensitivity modeled in AESC 2018.

Table 48. Avoided energy costs, AESC 2021 vs. AESC 2018 (15-year levelized costs, 2021 $ per kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	1	Connecticut	$0.059	$0.057	$0.043	$0.040
	2	Massachusetts	$0.062	$0.060	$0.047	$0.044
	3	Maine	$0.057	$0.056	$0.042	$0.039
	4	New Hampshire	$0.058	$0.057	$0.043	$0.040
	5	Rhode Island	$0.065	$0.064	$0.050	$0.047
	6	Vermont	$0.054	$0.053	$0.039	$0.036
AESC 2018	1	Connecticut	$0.063	$0.059	$0.049	$0.043
	2	Massachusetts	$0.062	$0.058	$0.049	$0.043
	3	Maine	$0.058	$0.054	$0.045	$0.039
	4	New Hampshire	$0.063	$0.060	$0.051	$0.044
	5	Rhode Island	$0.061	$0.057	$0.048	$0.042
	6	Vermont	$0.062	$0.058	$0.049	$0.042
Delta	1	Connecticut	-$0.005	-$0.002	-$0.006	-$0.003
	2	Massachusetts	-$0.001	$0.003	-$0.002	$0.001
	3	Maine	$0.000	$0.002	-$0.003	$0.000
	4	New Hampshire	-$0.005	-$0.003	-$0.008	-$0.004
	5	Rhode Island	$0.003	$0.007	$0.002	$0.005
	6	Vermont	-$0.008	-$0.005	-$0.010	-$0.006
Percent Difference	1	Connecticut	-7%	-3%	-12%	-7%
	2	Massachusetts	-1%	5%	-4%	2%
	3	Maine	0%	4%	-6%	1%
	4	New Hampshire	-8%	-5%	-15%	-8%
	5	Rhode Island	6%	12%	5%	12%
	6	Vermont	-13%	-8%	-20%	-14%

Notes: These costs are the sum of wholesale energy costs and wholesale costs of RPS compliance, increased by a wholesale risk premium of 8 percent, except for Vermont, which uses a wholesale risk premium of 11.1 percent. All costs have been converted to 2021 dollars per kWh. Levelization periods are 2018–2032 for AESC 2018 and 2021–2035 for AESC 2018. The real discount rate is 1.34 percent for AESC 2018 and 0.81 percent for AESC 2021. Values do not include losses.

6.2. Benchmarking the EnCompass energy model

The AESC 2021 Study Group required a calibration of the dispatch model used with actual, historical data. To complete this, the Synapse Team developed modeling inputs that reflect our best understanding of electric system market operations in 2019. This included assumptions relating to available generating units, fuel prices, and system demand.

Figure 41 compares actual day-ahead locational marginal prices (LMP) for each New England region reported on by ISO New England against the same prices modeled in EnCompass for 2019.[165] 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 2019 are 3 percent higher than actual historical LMPs. For all regions, modeled 2019 LMPs range from 1 percent higher to 3 percent higher than actual 2019 LMPs.

Figure 41. Comparison of 2019 historical and simulated 2019 locational marginal prices

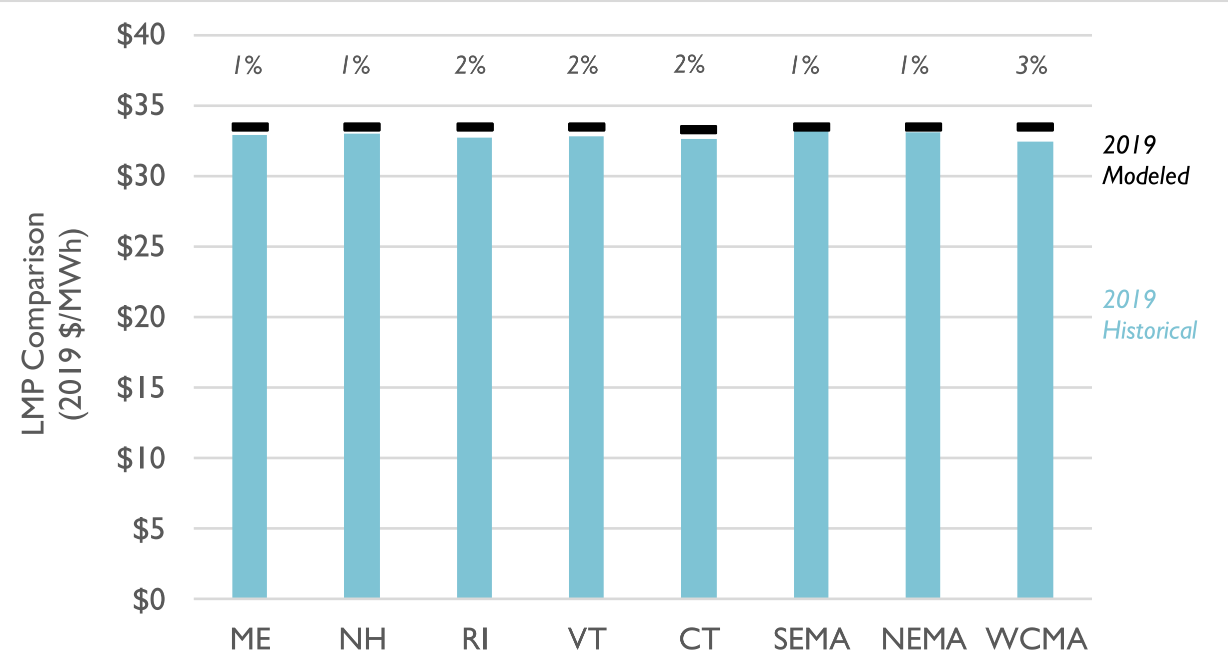


Figure 42 compares the monthly modeled LMPs for 2019 in the WCMA region against actual 2019 LMPs for the same region, and Figure 43 compares hourly modeled New England-wide average LMPs for 2019 against actual hourly 2019 LMPs for New England.[166] Our calibration for 2019 produces differences between modeled results and actual historical prices in line with the differences observed between a calibrated 2016 year from the 2018 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 2019. 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

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[165] Actual LMP data is available from the ISO New England website at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

[166] 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.

model) and the production cost model's 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). These differences may imply that depending on variations in future years, some hourly avoided costs may be underestimated while some others will be overestimated.

Figure 42. Comparison of 2019 historical and simulated 2019 locational marginal prices for the WCMA region (monthly)

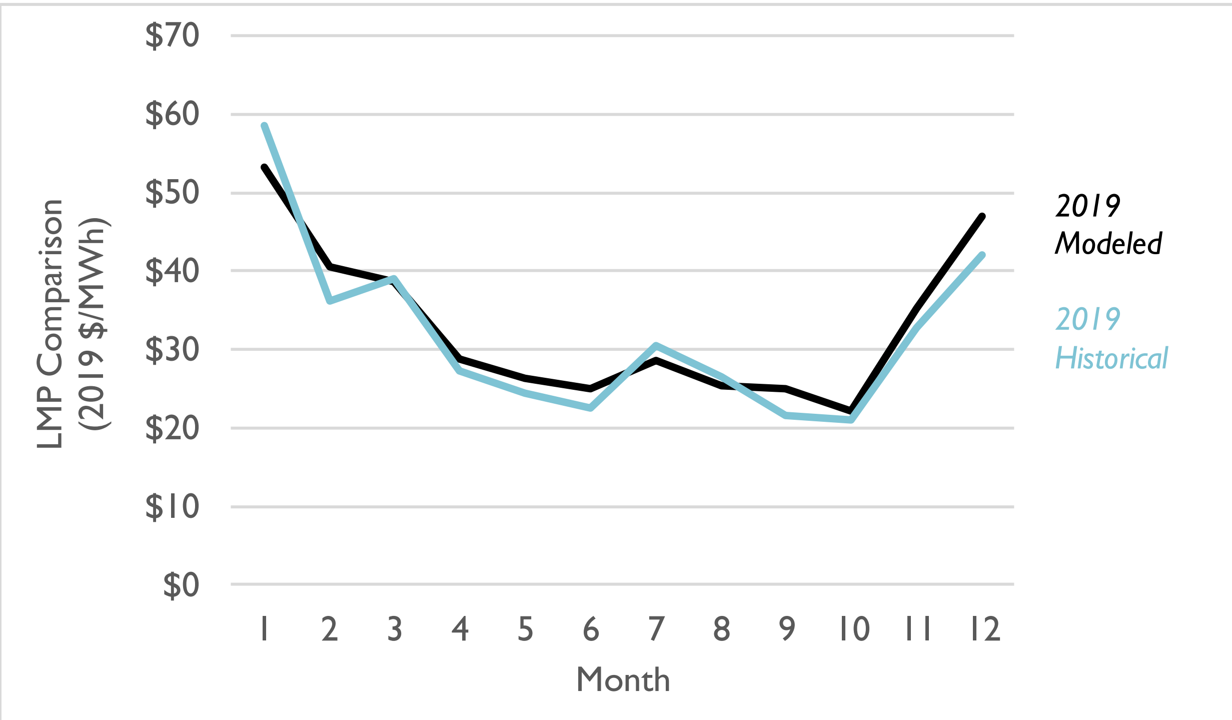
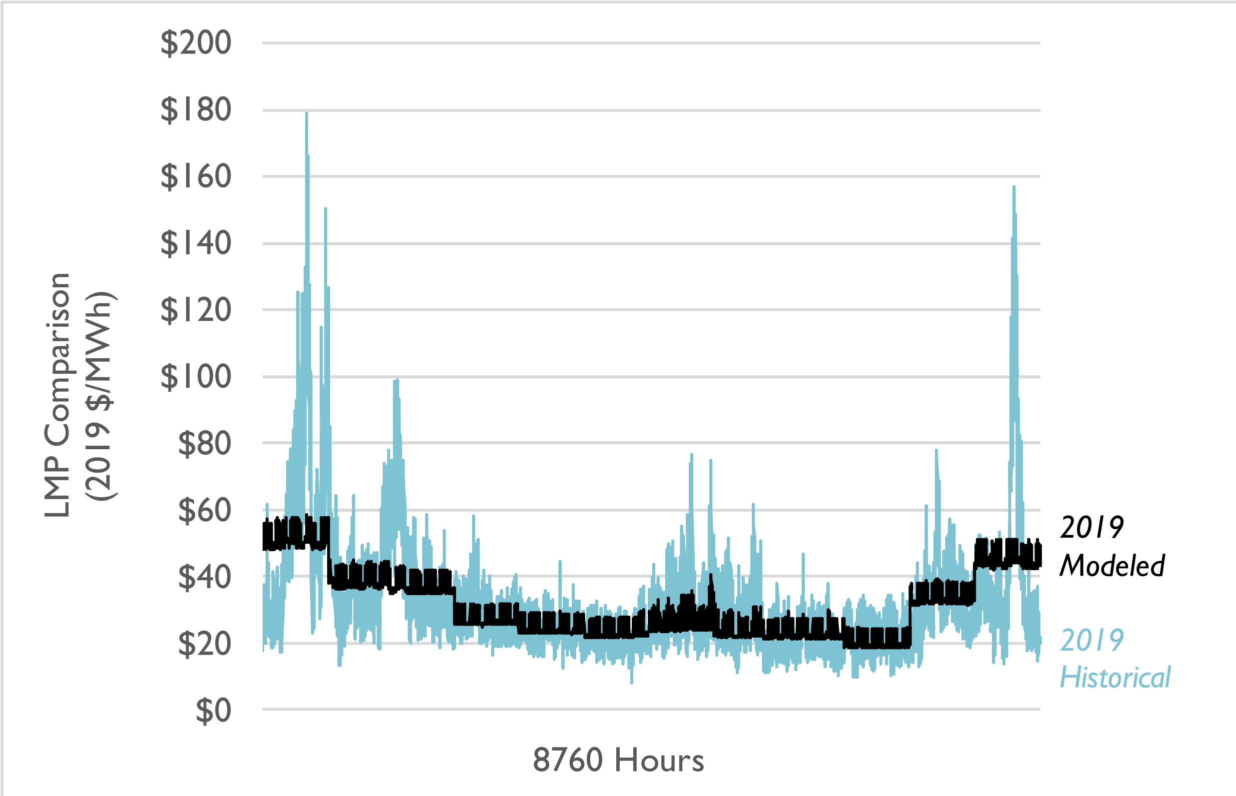


Figure 43. Comparison of 2019 historical and simulated 2019 locational marginal prices for New England (hourly)



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[167] of RPS[168] or Renewable Energy Standards[169] (RES) within each of the six New England states. Table 49, Table 50, Table 51, and Table 52 list the avoided costs of compliance for Counterfactuals #1, #2, #3, and #4, respectively.[170] Generally speaking, avoided costs are lowest in Counterfactual #2. Avoided costs are higher in Counterfactual #1 as a result of increased load and increased demand for RECs. Avoided costs are highest in Counterfactual #3 and #4, which feature the same set of avoided costs and have the highest loads (as they both ignore any energy efficiency added in 2021 or later, but also model additional load from building electrification).

Table 49. Avoided cost of RPS compliance for Counterfactual #1 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$6.59	$6.92	$5.61	$2.66	$14.96	$1.34
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.05	$5.44	$0.03	$2.56
Total	**$7.93**	**$7.37**	**$11.81**	**$8.10**	**$14.99**	**$3.90**

Table 50. Avoided cost of RPS compliance for Counterfactual #2 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$3.43	$3.10	$3.10	$1.31	$5.62	$0.75
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$1.80	$5.11	$0.03	$1.93
Total	**$4.77**	**$3.55**	**$9.04**	**$6.41**	**$5.66**	**$2.67**

Table 51. Avoided cost of RPS compliance for Counterfactual #3 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

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

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

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

[170] All values are levelized over 15 years and include energy losses.

Table 52. Avoided cost of RPS compliance for Counterfactual #4 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

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 avoided cost of RPS compliance is not equal to the REC price, however. Instead, the avoided cost is a function of both 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 53 shows that avoided costs projected in AESC 2021 are generally higher than those projected in AESC 2018. This is primarily due to recent (or anticipated) increases in RPS target obligations combined with expected increases in load due to electrification. Increases in the cost of RPS compliance in states that have not increased RPS targets (e.g., New Hampshire) are due to an increase in REC demand in the New England-wide REC market, of which all six states are participants.

Table 53. Avoided costs in AESC 2018 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$3.00	$0.22	$1.83	$1.61	$2.54	$0.56
MA CES	-	-	$0.48	-	-	-
All Other Classes	$1.00	$0.33	$1.53	$3.65	$0.03	$1.55
Total	**$4.00**	**$0.55**	**$3.84**	**$5.25**	**$2.57**	**$2.12**

Notes: Values have been converted from 2018 dollars to 2021 dollars. All values shown use a 9 percent loss factor, consistent with AESC 2021, rather than the 8 percent loss factor used in AESC 2018.

7.1. Assumptions and methodology

The purpose of this section is to describe the assumptions and methodology for forecasting the avoided cost of RPS and Massachusetts CES and CPS compliance. REC price forecasts are developed for each RPS sub-category and are based on expectations regarding eligible supply, annual demand targets, and—where applicable—the long-term cost of entry of renewable energy additions. These forecasts are converted to an avoided cost of RPS, CES, and CPS compliance on a dollar per MWh basis. Voluntary demands for Class 1 RECs (such as a portion of corporate renewable energy purchases and community choice aggregation) are also taken into account as a factor influencing Class 1 REC prices.

Renewable portfolio standards and clean energy standards

All six New England states have active RPS or RES policies—referred to hereafter as RPS. Each RPS program has multiple classes—referred to as tiers in Vermont—which are used to differentiate these policy mandates by technology, vintage, emissions, and other criteria that reflect state-specific policy objectives. Massachusetts also has a CES, which is met in large part by the MA Class I RPS obligation. It also has a "CES-E" for existing non-emitting resources—specifically nuclear and hydroelectric facilities from New Hampshire, Connecticut, and eastern Canada. Finally, Massachusetts regulations also include an Alternative Energy Portfolio Standard (APS), which applies to combined heat and power, renewable thermal, flywheel storage, fuel cells, and waste-to-energy, and increases by 0.25 percent per year indefinitely. While largely supporting non-renewable resources, APS program targets and avoided cost are nonetheless included in this section because the mandate is avoided by energy efficiency in the same manner as the RPS. Table 54 provides a summary overview of RPS and CES obligations throughout New England. Maine Class IA and MA CES-E are new policy additions since AESC 2018.

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 attained. Massachusetts Class I is the notable exception to this rule; it increases indefinitely—presumably until the sum of all RPS and CES mandates reaches 100 percent. Class II,[171] Class III, Class IV, and other "existing" supply obligations focus on generators that were already in operation prior to the adoption of RPS programs. These policies are intended to maintain the pre-RPS 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 periodic adjustment based either on supply conditions or policymaker discretion. The percentage targets for each class are summarized below in Table 55 and Table 56.

[171] With the exception of NH-II (which is dedicated to "new" solar) and possibly CT-II (which is dedicated to waste-to-energy and is without a vintage requirement).

Table 54. Summary of RPS and CES classes

State	RPS Class or Tier	COD Threshold	Eligibility Notes
Connecticut	Class I	No threshold	Subject to emissions threshold
	Class II	No threshold	Dedicated to WTE; Class I resources also eligible
	Class III	No threshold	Conservation and load management resources
Maine	Class I	Beginning 9/1/2005	Allows refurbished facilities
	Class IA	Beginning 9/1/2005	Does not allow refurbished facilities
	Class II	Before 9/1/2005	Allows hydro up to 100 MW
Massachusetts	Class I	Beginning 1/1/1998	Includes two solar carve-outs
	Class II-Non-WTE	Before 1/1/1998	Includes same biomass standards as Class I
	Class II-WTE	Before 1/1/1998	Dedicated class for waste-to-energy
	APS	Beginning 1/1/2008	Combined heat and power, useful thermal energy
	CES	Beginning 1/1/2011	MA Class I certified resources also eligible
	CES-E	Before 1/1/2011	Nuclear & hydro from NH, CT & eastern Canada
	CPS	No threshold	New MA-1, existing MA-1 w/ storage, DRR
New Hampshire	Class I	Beginning 1/1/2006	Includes a thermal carve-out
	Class II	Beginning 1/1/2006	Solar only
	Class III	Before 1/1/2006	Dedicated to biomass and LFG
	Class IV	Before 1/1/2006	Small hydro only
Rhode Island	New	Beginning 1/1/1998	Fuel standard requirements apply
	Existing	Before 1/1/1998	Fuel standard requirements apply
Vermont	Tier I	No threshold	Class II and RE portion of imports also eligible
	Tier II	Beginning 1/1/2015	Must be in-state and < 5 MW
	Tier III	Beginning 1/1/2015	Class II resources also eligible

Notes: The COD threshold is the date after which a project must have commenced commercial operation in order to be eligible. For the Massachusetts CES, eligible projects must have a COD on or after 1/1/2011; eligible facilities from adjacent control areas must be delivered over transmission energized on or after 1/1/2017. "DRR" are Demand Response Resources; for more information, see https://www.mass.gov/service-details/program-summaries.

In addition to distinguishing between new and existing supply, 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. These classes are also included in Table 54 and their respective targets are summarized in Table 56. For simplicity, this discussion includes these obligations under "RPS and CES requirements," even though some classes include resources that are not renewable.

RPS and CES compliance assumptions

AESC 2021 assumes that each retail 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 are calculated by multiplying obligated load[172] (adjusted for contract exemptions) by the applicable annual class-specific RPS percentage target. The forecast of obligated load is based on the aggregate impact of econometric load, energy efficiency, active demand response, and electrification described in Section 4.3: *New England system demand*. This includes a detailed forecast of BTM generation, which is critical because it both reduces obligated load and generates RECs for RPS compliance.[173] In all states, RPS targets are defined as a percentage of obligated load. Table 55 summarizes RPS targets for new renewable energy additions, while Table 56 summarizes RPS targets for existing resource categories. Beginning in 2025, MA Class I targets are based on legislative proposals expected to pass during the 2020 session. The Massachusetts legislature is also considering a "Greenhouse Gas Emissions Standard" (GGES) for municipal utilities. The GGES is expected to create incremental demand for new renewable capacity beginning 2024. Beginning in 2022, RI "New" targets are assumed to align with Executive Order 20-01 and *The Road to 100% Renewable Electricity by 2030 in Rhode Island* report, which calls for 100 percent renewable electricity by 2030. All other targets reflect current statutes.

[172] Municipal utilities are currently exempted from RPS and CES obligations in all states except Vermont. These exemptions are assumed to remain for the duration of the study period.

[173] Several states have begun to consider whether load offset by BTM generation should be added to the total RPS obligation. These discussions are preliminary, however, and therefore not included in this analysis.

Table 55. Summary of modeled RPS targets for new resource categories

	CT-I	ME-I	ME-IA	MA-I[174]	MA-SREC-I[175]	MA-SREC-II[176]	MA CPS (est.)	MA APS	NH-I[177]	NH-I Thermal	NH-II	RI-New	VT-II
2021	22.5%	10%	5%	18%	1.66%	3.92%	3.0%	5.25%	11.4%	1.8%	0.7%	15.5%	3.4%
2022	24%	10%	8%	20%	TBD	TBD	4.5%	5.50%	12.3%	2.0%	0.7%	24.7%	4.0%
2023	26%	10%	11%	22%	TBD	TBD	6.0%	5.75%	13.2%	2.2%	0.7%	33.8%	4.6%
2024	28%	10%	15%	24%	TBD	TBD	7.5%	6.00%	14.1%	2.2%	0.7%	43%	5.2%
2025	30%	10%	19%	27%	TBD	TBD	9.5%	6.25%	15%	2.2%	0.7%	52.2%	5.8%
2026	32%	10%	23%	30%	TBD	TBD	11.75%	6.50%	15%	2.2%	0.7%	61.3%	6.4%
2027	34%	10%	27%	33%	TBD	TBD	13.75%	6.75%	15%	2.2%	0.7%	70.5%	7.0%
2028	36%	10%	31%	36%	TBD	TBD	15.25%	7.00%	15%	2.2%	0.7%	79.7%	7.6%
2029	38%	10%	35%	39%	TBD	TBD	16.75%	7.25%	15%	2.2%	0.7%	88.8%	8.2%
2030	40%	10%	40%	40%	TBD	TBD	18.25%	7.50%	15%	2.2%	0.7%	98%	8.8%
2031	40%	10%	40%	41%	TBD	TBD	19.75%	7.75%	15%	2.2%	0.7%	98%	9.4%
2032	40%	10%	40%	42%	TBD	TBD	21.25%	8.00%	15%	2.2%	0.7%	98%	10%
2033	40%	10%	40%	43%	TBD	TBD	22.75%	8.25%	15%	2.2%	0.7%	98%	10%
2034	40%	10%	40%	44%	TBD	TBD	24.25%	8.50%	15%	2.2%	0.7%	98%	10%
2035	40%	10%	40%	45%	TBD	TBD	25.75%	8.75%	15%	2.2%	0.7%	98%	10%
2036	40%	10%	40%	46%	TBD	TBD	TBD	9.00%	15%	2.2%	0.7%	98%	10%
2037	40%	10%	40%	47%	TBD	TBD	TBD	9.25%	15%	2.2%	0.7%	98%	10%
2038	40%	10%	40%	48%	TBD	TBD	TBD	9.50%	15%	2.2%	0.7%	98%	10%
2039	40%	10%	40%	49%	TBD	TBD	TBD	9.75%	15%	2.2%	0.7%	98%	10%
2040	40%	10%	40%	50%	TBD	TBD	TBD	10.00%	15%	2.2%	0.7%	98%	10%
2041	40%	10%	40%	51%	TBD	TBD	TBD	10.25%	15%	2.2%	0.7%	98%	10%
2042	40%	10%	40%	52%	TBD	TBD	TBD	10.50%	15%	2.2%	0.7%	98%	10%
2043	40%	10%	40%	53%	TBD	TBD	TBD	10.75%	15%	2.2%	0.7%	98%	10%
2044	40%	10%	40%	54%	TBD	TBD	TBD	11.00%	15%	2.2%	0.7%	98%	10%
2045	40%	10%	40%	55%	TBD	TBD	TBD	11.25%	15%	2.2%	0.7%	98%	10%
2046	40%	10%	40%	56%	TBD	TBD	TBD	11.50%	15%	2.2%	0.7%	98%	10%
2047	40%	10%	40%	57%	TBD	TBD	TBD	11.75%	15%	2.2%	0.7%	98%	10%
2048	40%	10%	40%	58%	TBD	TBD	TBD	12.00%	15%	2.2%	0.7%	98%	10%
2049	40%	10%	40%	59%	TBD	TBD	TBD	12.25%	15%	2.2%	0.7%	98%	10%
2050	40%	10%	40%	60%	TBD	TBD	TBD	12.50%	15%	2.2%	0.7%	98%	10%

Notes: The modeling horizon of AESC 2021 is through 2035; percentage targets are shown through 2050 for reference.

[174] This is the gross MA-I target. The MA-SREC target is carved out of the MA-I target.

[175] Without exemptions for load under contract.

[176] Without exemptions for load under contract.

[177] This is the gross NH-I target. The NH-I Thermal target is carved out of the NH-I target.

Table 56. Summary of RPS targets for other resource categories

	CT-II[(a)]	CT-III	ME-II	MA-II Non-WTE	MA-II WTE	MA CES	MA CES-E[(b)]	NH-III[(c)]	NH-IV	RI-Existing	VT-I[(d)]	VT-III
2021	4%	4%	30%	3.56%	3.5%	22%	20%	8%	1.5%	2%	55.6%	4.67%
2022	4%	4%	30%	3.6%	3.5%	24%	20%	8%	1.5%	2%	55%	5.33%
2023	4%	4%	30%	TBD	3.5%	26%	20%	8%	1.5%	2%	58.4%	6.00%
2024	4%	4%	30%	TBD	3.5%	28%	20%	8%	1.5%	2%	57.8%	6.67%
2025	4%	4%	30%	TBD	3.5%	30%	20%	8%	1.5%	2%	57.2%	7.33%
2026	4%	4%	30%	TBD	3.5%	32%	20%	8%	1.5%	2%	60.6%	8.00%
2027	4%	4%	30%	TBD	3.5%	34%	20%	8%	1.5%	2%	60%	8.67%
2028	4%	4%	30%	TBD	3.5%	36%	20%	8%	1.5%	2%	59.4%	9.33%
2029	4%	4%	30%	TBD	3.5%	38%	20%	8%	1.5%	2%	62.8%	10.0%
2030	4%	4%	30%	TBD	3.5%	40%	20%	8%	1.5%	2%	62.2%	10.67%
2031	4%	4%	30%	TBD	3.5%	42%	20%	8%	1.5%	2%	61.6%	11.33%
2032	4%	4%	30%	TBD	3.5%	44%	20%	8%	1.5%	2%	65%	12.0%
2033	4%	4%	30%	TBD	3.5%	46%	20%	8%	1.5%	2%	65%	12.0%
2034	4%	4%	30%	TBD	3.5%	48%	20%	8%	1.5%	2%	65%	12.0%
2035	4%	4%	30%	TBD	3.5%	50%	20%	8%	1.5%	2%	65%	12.0%
2036	4%	4%	30%	TBD	3.5%	52%	20%	8%	1.5%	2%	65%	12.0%
2037	4%	4%	30%	TBD	3.5%	54%	20%	8%	1.5%	2%	65%	12.0%
2038	4%	4%	30%	TBD	3.5%	56%	20%	8%	1.5%	2%	65%	12.0%
2039	4%	4%	30%	TBD	3.5%	58%	20%	8%	1.5%	2%	65%	12.0%
2040	4%	4%	30%	TBD	3.5%	60%	20%	8%	1.5%	2%	65%	12.0%
2041	4%	4%	30%	TBD	3.5%	62%	20%	8%	1.5%	2%	65%	12.0%
2042	4%	4%	30%	TBD	3.5%	64%	20%	8%	1.5%	2%	65%	12.0%
2043	4%	4%	30%	TBD	3.5%	66%	20%	8%	1.5%	2%	65%	12.0%
2044	4%	4%	30%	TBD	3.5%	68%	20%	8%	1.5%	2%	65%	12.0%
2045	4%	4%	30%	TBD	3.5%	70%	20%	8%	1.5%	2%	65%	12.0%
2046	4%	4%	30%	TBD	3.5%	72%	20%	8%	1.5%	2%	65%	12.0%
2047	4%	4%	30%	TBD	3.5%	74%	20%	8%	1.5%	2%	65%	12.0%
2048	4%	4%	30%	TBD	3.5%	76%	20%	8%	1.5%	2%	65%	12.0%
2049	4%	4%	30%	TBD	3.5%	78%	20%	8%	1.5%	2%	65%	12.0%
2050	4%	4%	30%	TBD	3.5%	80%	20%	8%	1.5%	2%	65%	12.0%

Notes: Except Massachusetts Class I and Rhode Island "New" targets, RPS target assumptions are based on current law. The modeling horizon of AESC 2021 is through 2035; percentage targets are shown through 2050 for reference.
(a) Connecticut Class I supply can be counted toward compliance with Class II requirements
(b) The CES-E target is 20 percent in 2021 and 2022. Beginning in 2023, the CES-E percentage obligation is determined by a formula that is tier to historical production.
(c) The NH PUC has the authority to review and reduce the NH-III RPS target, retroactively, each year.
(d) Vermont Tier I is derived by subtracting the Tier II requirement from the total VT RES goal. Tier II RECs can be counted toward compliance with Tier I requirements.

Alternative compliance payments

Table 57 provides a summary of ACP values for each RPS category. Note that some ACP values stay constant (in nominal terms) throughout the study period, while other values change over time.

Table 57. Summary of Alternative Compliance Payment levels

		2020 Alternative Compliance Payment (nominal $ per MWh)	Notes
CT	Class I	$55.00	$40 beginning 2021. Fixed and flat.
	Class II	$25.00	Fixed and flat.
	Class III	$31.00	Fixed and flat. There is also a $10 floor price.
MA	Class I	$71.57	Adjusted by CPI each year.
	Solar Carve-out I	$384.00	Schedule set by DOER.
	Solar Carve-out II	$316.00	Schedule set by DOER.
	Class II – RE	$29.37	Adjusted by CPI each year.
	Class II – WTE	$11.75	Adjusted by CPI each year.
	APS	$23.50	Adjusted by CPI each year.
	CES	$53.88	75% of Class I ACP in 2020, 50% in 2021 and after
	CES-E	NA	10% of Class I ACP
RI	New	$71.58	Adjusted by CPI each year.
	Existing	$71.58	Adjusted by CPI each year.
ME	Class I	$50.00	Fixed and flat.
	Class II	$50.00	Fixed and flat.
NH	Class I	$57.61	Adjusted by ½ of CPI each year.
	Class I - Thermal	$26.18	Adjusted by ½ of CPI each year.
	Class II	$57.61	Adjusted by ½ of CPI each year.
	Class III	$34.54	Adjusted by CPI each year.
	Class IV	$29.06	Adjusted by CPI each year.
VT	Tier I	$10.71	Adjusted by CPI each year.
	Tier II	$62.74	Adjusted by CPI each year.
	Tier III	$62.74	Adjusted by CPI each year.

Notes: 2021 Alternative Compliance Payments have not yet been released.
The MA RPS regulations are currently under review. AESC 2021 assumes that the proposed Class I ACP of $60 per MWh in 2021, $50 per MWh in 2022, and $40 per MWh in 2023 and thereafter (fixed and flat) will be approved as part of this review. AESC 2021 further assumes that CES ACP and CES-E ACP will continue to be indexed to Class I ACP at the current ratios.
There is no MA CES-E compliance obligation until 2021.
VT Tier II values are estimated based on $60 per MWh in 2018, escalated by CPI thereafter. VT does not appear to publish its ACP rates.

Impacts of the COVID-19 pandemic on Renewable Energy Deployment and Avoided Cost of RPS Compliance

The COVID-19 pandemic has impacted, and will continue to impact, many facets of the renewable energy industry. For large-scale projects in the pipeline, estimates of COVID-induced delays are based on project-specific research and interviews with developers and investors (see Figure 44). For distributed generation projects, the models assume a range of potential delay impacts to near-term projects. The distributed generation delay options are summarized in Table 58, which shows the number of months of delay modeled for projects expected to come on-line each year from 2020 to 2023. Projects with expected commercial operation dates in 2023 or later are not expected to face COVID-induced delays. The *Base Impact* case is used for all counterfactual cases.

Table 58. Range of potential project delays resulting from COVID-19 pandemic

	2020	2021	2022	2023
Low Impact	2 months	1 month	0.5 months	No delay
Base Impact	3 months	1.5 months	0.75 months	No delay
High Impact	5 months	2.5 months	1.25 months	No delay

Figure 44. Potential impacts of the COVID-19 pandemic on renewable energy deployment

Impacts on Project Development Process

- Site access impaired, leading to delays in site control
- Stay-at-home orders, distancing requirements, and resulting limits to on-site activity
- Permitting and construction delays
- Supply chain disruptions
- Most delays translate into increased cost

Impacts on Project Development Pipeline

- Stay-at-home and distancing orders increase costs
- Contracted projects face reduction in available capital
- Little to no appetite for merchant risk
- Schedule delays impair ability to access expiring federal incentives

Impacts on Investment Climate

- Availability of capital depends on developer type and funding source
- Pool of capital expected to contract as a result of general recessive conditions (cash equity) and reduced federal income tax liability (tax equity)
- Lenders (and all investors) challenged to accurately assess risk in this environment
- Offtaker credit risk subject to particular scrutiny
- However, absence of other attractive investments likely to prevent cost of capital from increasing

Impacts on Operating Projects

- Reduced market prices; ISO New England calls for curtailment in export-constrained areas
- Increased O&M costs; exacerbated by supply chain disruptions
- Travel limitations impact O&M crews, resulting in increased unplanned outages
- Limitations on mobility of fuel suppliers (biomass)

7.2. Renewable Energy Certificate (REC) Price Forecasting

This section summarizes REC price forecasting outcomes. Class 1, or "New" markets, are discussed first followed by "Existing" markets. For context, this section also includes a summary of historical REC prices in each market, as represented by broker quotations.

Historical renewable energy certificate prices

We rely upon recent broker quotes, in part, to inform 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, analysts should 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 59 shows annual average historical REC prices for new RPS markets. Table 60 shows historical REC prices for existing RPS markets

Table 59. Annual average historical REC prices, New supply: 2015-2020 (nominal $ per MWh)

		2015	2016	2017	2018	2019	2020
CT	Class I	$44	$22	$12	$8	$35	$41
MA	Class I	$44	$22	$12	$8	$35	$41
	APS	$21	$21	$20	$17	$9	$7
	CES	NA	NA	NA	NA	NA	NA
RI	New	$43	$23	$12	$7	$34	$41
ME	Class I & IA	$18	$22	$8	$3	$2	$3
NH	Class I	$45	$24	$12	$8	$35	$41
	Class II - Solar	$51	$43	$26	$13	$27	$35
VT	Tier II	NA	NA	NA	NA	NA	NA*
	Tier III	NA	NA	NA	NA	NA	NA*

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

Table 60. Annual average historical REC prices, Existing supply: 2015-2020 (nominal $ per MWh)

		2015	2016	2017	2018	2019	2020
CT	Class II	$1	$1	$7	$6	$20	$20
	Class III	$27	$27	$26	$26	$22	$13
MA	Class II – Non-WTE	$27	$26	$26	$26	$23	$20
	Class II – WTE	$6	$6	$6	$6	$10	$11
	CES-E	NA	NA	NA	NA	NA	$2.75
RI	Existing	$1	$1	$1	$1	$1	$1
ME	Class II	$0	$1	$1	$1	$1	$1
NH	Class III	$37	$28	$23	$13	$40	$38
	Class IV	$25	$25	$25	$26	$26	$23
VT	Tier I	NA	NA	NA	NA	NA	NA*

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

Forecasting renewable energy certificate prices for compliance with Class I RPS obligations

The key input to calculating the avoided cost of RPS compliance is REC price. Class I REC prices are forecast using the REMO and Solar Market Study (SMS) models.[178] We describe key methodological steps and assumptions throughout this document. Sustainable Energy Advantage forecasts non-Class I markets with a range of class-specific methodologies, which we describe later in this section.

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

The Class I REC price forecast from 2021 to approximately 2030 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 categories listed in Table 55. These resources may fall into one of the following categories:

a) Certified supply, operating and located in ISO New England

b) Certified supply, operating and imported from adjacent control areas

c) Additional potential imports from adjacent control areas, delivered over existing ties; and

d) Near-term committed renewable resources that (i) are in the interconnection queue; (ii) have been RPS-certified in one or more multiple New England states; (iii) secured financing; or (iv) obtained long-term contracts, either with distribution utilities through competitive solicitations, or through other means.

[178] See Section 4.1: *AESC 2021 modeling framework* for more information.

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

In addition to the resources described above, we forecast the generation from renewable resources that are expected to come on-line as a result of existing state procurement policies and incentive programs, including but not limited to:

Large-scale renewables

- MA Sec. 83C Offshore Wind Procurement: 1,600 MW by 2026 (Vineyard & Mayflower Wind). *Project selections have been made, and timing updated, since AESC 2018.*
- MA Additional Offshore Wind Procurement, DOER Authority: up to 1,600 MW by 2031. *This procurement policy goal is new since AESC 2018.*
- MA Offshore Wind Procurement, Additional 83C Authority: 2,400 MW (to be procured by 12/31/2027) is expected to be approved during the 2021 legislative session.
- MA Sec. 83D Hydro Procurement: Delivery of 9.45 TWh beginning 7/1/2023 (date on which NECEC is assumed to be energized). *Timing and resource assumptions have been updated since AESC 2018.*
- CT & RI Joint Offshore Wind Procurement: 700 MW (Revolution Wind) by 2025. *Project selections have been made, and timing updated, since AESC 2018.*
- CT Offshore Wind Procurement: 804 MW (Park City Wind) by 2026. *Project selections have been made, and timing updated, since AESC 2018.*
- RI Additional Offshore Wind Procurement: 600 MW in 2021 as announced by Governor Raimondo. *This procurement is new since AESC 2018.*
- ME Long-Term Procurement: Approximately 1 TWh by 2025. *This procurement policy goal is new since AESC 2018.* Tranche 1 was completed in 2020. The RFP for Tranche 2 was released in January 2021.

Distributed generation

- Solar Massachusetts Renewable Target (SMART) Program: 3,200 MW by 2031. *Program expanded from 1,600 to 3,200 MW since AESC 2018.*[179]

[179] To model the hourly generation impacts from distributed solar in the SMART program and all other distributed solar programs, we rely on Horizons Energy's National Database for solar load shapes. Horizons Energy developed the load shapes using irradiation patterns from NREL's PVWatts. They were chosen from airport locations that were closest to the market areas included in the National Database.

- Solar Massachusetts Renewable Target (SMART) Program Expansion: A 2,000 MW expansion (assumed to be reached by 2033) is included in legislation assumed to pass during the 2021 session.
- CT Low and Zero Emissions Renewable Energy Certificate (LREC/ZREC) Programs. *Quantity and timing updated since AESC 2018.*
- CT Low- and Zero-Emissions Tariff Programs. *This program is new since AESC 2018.*
- CT Residential Solar Home REC (RSIP/SHREC) and Tariff Programs. *The Residential Tariff Program is new since AESC 2018.*
- RI Renewable Energy Growth Program (including expansions). *Timing updated since AESC 2018.*[180]
- VT Standard Offer. *Timing updated since AESC 2018.*
- ME Distributed Generation Solar Policy: Large-Scale Shared; Commercial & Institutional. *This program is new since AESC 2018.*
- Net metering and virtual new metering, as applicable, in all New England states. *Quantity and timing updated since AESC 2018.*

Given the eligibility interaction between the MA CES and MA Class I RPS markets, REC and Clean Energy Credit (CEC) price forecasts are modeled interdependently. RECs and ACPs used for Massachusetts Class I compliance will be counted toward CES compliance. Incremental CES demand above the Massachusetts Class I RPS will be 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.

Forecasted Class I REC supply is 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 are used to inform the forecast of near-term Class I REC prices.

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 ACP.
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $2/MWh, reflecting transaction and risk management costs.

[180] Here, and throughout this section, "timing" refers to the estimate of when programmatic capacity will come online.

- 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.

Solar Renewable Energy Certificate (SREC) prices are forecasted using a separate set of proprietary models, developed for Sustainable Energy Advantage's *Massachusetts Solar Market Study*.

Long-term cost of entry and renewable energy additions

The long-term Class I REC price forecast (approximately 2030–2050) 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—and the extrapolation thereof. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential that sorts resources from lowest cost of entry to highest cost of entry. The resources in the supply curve model are represented by 1,277 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 resource potential studies commissioned by Sustainable Energy Advantage and is proprietary. The cost components of the supply curve analysis are derived from a combination of public (e.g., NREL's ATB) and confidential sources (e.g., Sustainable Energy Advantage 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, biogas, hydro, landfill gas, and tidal resources.[181] While utility-scale solar is the largest potential resource by MW, land-based wind is the largest source by number of blocks (modeled as 1,031 separate individual land-based wind sites). Modeled wind blocks vary by state, land area, number and size of turbines in each project, wind speed, topography, and distance from transmission.

Resources from the supply curve are 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,[182] 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 O&M costs, generator-lead interconnection costs,[183] transmission network upgrade costs,[184] and wind integration costs. Phase-out

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

[182] For this analysis, we assume 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.

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

[184] It is assumed that 15-33 percent of the transmission costs are socialized and thereby not borne by the generators.

of the Federal Production Tax Credit and phase-down of the Investment Tax Credit are modeled as adopted in the *Further Consolidated Appropriations Act of 2020*.

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 for market entry, or the additional revenue the project would require in order to attract financing, by performing the following operation: we subtracted (a) the nominal levelized value of production consistent with the AESC 2021 projection of wholesale electric energy and capacity prices from (b) nominal levelized cost of marginal resources.[185] The nominal levelized cost of marginal resources is the amount the project needs in revenue on a levelized $/MWh basis, or:

1. The nominal levelized value of production is the amount the project would receive from selling energy and capacity into the wholesale market; and
2. 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 can never be negative.

Resource levelized cost is expected to undergo several changes throughout the analysis period. These changes include impacts resulting from capital cost decline, technological improvements (increasing capacity factors), and need for transmission solutions, as well as the level of federal tax credits.

The levelized commodity revenue over the life of each resource is based on the sum of energy and capacity prices. REC prices and avoided cost of RPS compliance are derived through an iterative approach. Draft REC prices were based on preliminary energy and capacity forecasts, and were then used to inform final energy and capacity prices. These final prices are inputs for the final REC price and

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

avoided RPS compliance cost calculation. See Figure 12 in Section 4.1: *AESC 2021 modeling framework* for more information on this process.

Class 1 or "New" REC price forecasts

Future REC prices in new renewables markets will be driven both by the cost of entry for renewable resources eligible in each state and by the quantity of state-specific supply compared to state-specific demand. RPS eligibility criteria differ by state, and so REC prices are differentiated by state and reflect state-specific expectations with respect to generator certification and LSE-banked compliance. Eligibility criteria also overlap across multiple states, and so the interaction of multi-state supplies and demands and the fungibility of RECs across markets are also considered in this analysis.

For New RPS categories, we assume that in the long run the price of RECs (and therefore the unit cost of RPS compliance) will be determined by the cost of new entry of the marginal renewable energy unit. To estimate the new or incremental REC cost of entry, we constructed a supply curve for incremental New England renewable energy potential based on various resource potential studies. The supply curve sorts the supply resources from the lowest cost of entry to the highest cost of entry.[186] The resources in the supply curve model are represented by 1,390 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.

The supply curve consists of land-based wind, offshore wind, utility-scale solar, biomass,[187] hydro, landfill gas, and tidal resources. The price for each block of the supply curve is estimated for each year. For each generator, we determine the 20-year levelized REC premium for market entry, or additional revenue the project would require to enable financing, by subtracting the nominal, levelized energy and capacity prices from the nominal levelized cost of marginal resources:

- 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 its commodities (energy and capacity) into the wholesale market; and
- The difference between the levelized cost and the levelized value represents the REC premium.

As described above, unless the revenue from REC prices can make up the REC premium, a project is unlikely to be developed. Resource blocks are sorted from low to high REC premium, and the

[186] These assumptions are based on technology assumptions compiled by Sustainable Energy Advantage, LLC from a range of studies and interviews with market participants, as well as in-house geospatial resource potential studies conducted by Sustainable Energy Advantage, LLC. Typical generator sizes, heat rates, availability and emission rates are consistent with technology assumptions used by ISO New England in its scenario planning process. The resulting supply curve is proprietary to Sustainable Energy Advantage, LLC.

[187] Including biogas and biodiesel.

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.

The estimated levelized cost of marginal resources is based on several key assumptions, including projections of capital costs, capital structure, 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 O&M costs, transmission and interconnection costs (as a function of voltage and distance from transmission), and wind integration costs.[188] The analysis assumes the currently planned phase-out of Federal Tax incentives.[189] Capital and operating costs were escalated over time using inflation.

We determined the levelized commodity revenue over the life of each resource based on the sum of energy and capacity prices, both utilizing preliminary AESC 2021 estimates of the FCM price and all-hour zonal LMP.

Resources from the supply curve are 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, are 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) for Counterfactual #1 is summarized in Table 61. REC premium for market entry (2021 $ per MWh). We assume CEC prices for the Massachusetts CES track MA-1 REC prices until CES-eligible hydro comes online (2023). Thereafter, once hydro contracted under MA Sec. 83D is used to fulfill 100 percent of the CES obligation, we assume a price of $0 because the cost of the 83D contracts cannot be avoided.

Even in years when there is market surplus, REC premiums are not necessarily equal to $0 per MWh. This is because we assume a level of banking injections (to hedge against future shortages) that mitigate potential price crashes that could occur even in years with a large surplus.

[188] We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[189] U.S. Office of Energy Efficiency & Renewable Energy. Last accessed March 10, 2021. "Residential and Commercial ITC Factsheets." *Energy.gov.* Available at https://www.energy.gov/eere/solar/downloads/residential-and-commercial-itc-factsheets.

Table 61. REC premium for market entry (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$39.69	$21.64	$21.64	$2.50	$55.01	$29.82	$44.33
2022	$38.61	$40.18	$40.18	$2.45	$40.18	$24.13	$43.44
2023	$30.14	$31.97	$31.97	$2.40	$31.34	$0.00	$42.60
2024	$20.96	$20.96	$20.96	$2.36	$20.96	$0.00	$35.59
2025	$13.68	$15.04	$15.04	$2.31	$13.90	$0.00	$29.30
2026	$13.56	$14.09	$14.09	$2.27	$13.22	$0.00	$29.59
2027	$12.09	$12.14	$12.14	$2.22	$10.17	$0.00	$34.20
2028	$10.29	$10.40	$10.40	$2.18	$8.44	$0.00	$32.22
2029	$9.89	$10.10	$10.10	$2.13	$8.06	$0.00	$30.26
2030	$22.77	$22.90	$22.90	$2.09	$22.84	$0.00	$28.42
2031	$22.02	$22.27	$22.27	$2.05	$22.14	$0.00	$26.60
2032	$21.62	$21.62	$21.62	$2.01	$21.62	$0.00	$18.85
2033	$7.34	$9.14	$9.14	$1.97	$5.27	$0.00	$17.15
2034	$9.45	$11.14	$11.14	$1.93	$7.65	$0.00	$15.52
2035	$12.67	$13.16	$13.16	$1.90	$12.06	$0.00	$13.95
Levelized (2021-2035)	**$19.38**	**$18.73**	**$18.73**	**$2.19**	**$20.05**	**$3.92**	**$29.99**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$4.50	$50.55	$23.80	$52.37	$61.13	$55.01	$31.21
2022	$4.41	$40.18	$23.55	$46.21	$49.42	$40.18	$31.20
2023	$4.32	$36.65	$23.33	$36.04	$47.46	$31.34	$31.21
2024	$4.24	$20.96	$20.58	$24.10	$20.96	$20.96	$20.96
2025	$4.16	$9.09	$18.17	$15.99	$13.50	$13.90	$13.90
2026	$4.08	$7.86	$16.03	$15.20	$15.70	$13.22	$13.22
2027	$4.00	$7.20	$14.14	$11.70	$18.12	$10.17	$10.17
2028	$3.92	$5.80	$12.49	$9.71	$15.80	$8.44	$8.44
2029	$3.84	$5.29	$11.00	$9.27	$15.13	$8.06	$8.06
2030	$3.77	$22.90	$9.72	$26.26	$22.90	$22.84	$22.84
2031	$3.69	$22.27	$8.57	$25.46	$22.27	$22.14	$22.14
2032	$3.62	$21.62	$7.56	$24.87	$21.62	$21.62	$21.62
2033	$3.55	$3.90	$6.67	$6.06	$11.56	$5.27	$5.27
2034	$3.48	$4.97	$5.89	$8.80	$13.44	$7.65	$7.65
2035	$3.41	$6.07	$5.20	$13.87	$15.06	$12.06	$12.06
Levelized (2021-2035)	**$3.95**	**$18.24**	**$14.15**	**$22.26**	**$24.88**	**$20.05**	**$17.65**

The REC premium (REC Price) results are highly dependent upon the forecast of wholesale electric energy market prices, including 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.

Forecasting renewable energy certificate prices for compliance with existing 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 must be tailored to a different set of market characteristics. Table 62 describes how REC prices for non-Class I markets are forecasted.

Table 62. REC price forecasting approaches

RPS Market	REC Price Forecast Approach
CT Class II	REC prices are estimated based on current broker quotes and are assumed to trend toward values which reflect a market in equilibrium over time. With limited eligible supply, REC prices are expected to remain modestly below the ACP.
CT Class III	REC prices are estimated based on current broker quotes and are assumed to remain near the minimum nominal Class III REC price of $10/MWh.
ME Class II	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and reflect an assumption of supply adequacy through the study period.
MA Class II – Non-WTE	In the near term, REC prices are estimated based on current broker quotes. In the long term, REC prices are forecasted as the lesser of the CT Class I REC price and 75 percent of the MA-II-Non-WTE ACP.
MA Class II – WTE	REC prices are estimated based on current broker quotes. With static supply and stable demand targets, REC prices are expected to remain at or near current levels.
MA APS	REC prices are estimated at 90% of the MA APS ACP.
MA CPS	Based on a proprietary model developed by Sustainable Energy Advantage, including preliminary assumptions before market data were available (circa Nov 2020), and derived as an average of six scenarios.
MA CES	CEC prices are the lesser of the MA Class I price and the CES ACP until CES-eligible hydropower is delivered pursuant to MA 83D contracts. Once these deliveries begin, CEC prices are assumed to decrease to $1/MWh. Once 83D deliveries begin, there will be no CEC "market" because supply will dramatically exceed demand and all eligible supply will be controlled by the distribution utilities. Separately, our understanding is that all CECs in excess of CES demand will be retired by the distribution utilities and their associated over-market costs (defined as the contract cost minus energy and capacity revenues collected upon liquidation into the market) will be collected from all distribution customers.
MA CES-E	REC prices are estimated based on current broker quotes and considering the interaction with other "existing" markets.
NH Class II	REC prices are estimated at the lesser of 105% of the MA Class I REC price and 90% of the NH Class II ACP
NH Class III	In the near term, REC prices are estimated based on current broker quotes. In the long term, REC prices are forecasted as 90% of the NH-III ACP, assuming a systemic shortage.
NH Class IV	In the near term, REC prices are estimated based on current broker quotes. In the long term, REC prices are forecasted as the lesser of the CT Class I REC, the MA Class II non-WTE REC price, and 75 percent of the NH Class IV ACP.
RI Existing	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and reflect an assumption of supply adequacy through the study period.
VT Tier I	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and reflect an assumption of supply adequacy through the study period.
VT Tier III	Based on the overlap in eligibility, REC prices are estimated based on the lesser of the VT Tier II REC price and the NH Class I Thermal Carve-out Price.

"Existing" REC price forecasts

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. Table 63 shows our projection of REC prices for existing resource categories. For reference, Table 60 shows annual average historical REC prices for Existing RPS markets.

Table 63. Summary of REC prices for existing resource categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$20.50	$12.00	$0.75	$23.25	$12.00	$3.50	$36.47	$23.24	$1.00	$0.88
2022	$20.09	$11.76	$0.74	$22.46	$13.23	$3.43	$36.03	$22.22	$0.98	$0.86
2023	$20.74	$11.53	$0.72	$22.46	$12.97	$3.36	$36.20	$22.23	$0.96	$0.84
2024	$22.37	$11.30	$0.71	$20.96	$12.72	$3.30	$36.33	$20.96	$0.94	$0.82
2025	$21.95	$11.09	$0.69	$13.68	$12.47	$3.23	$36.46	$13.68	$0.92	$0.81
2026	$21.52	$10.87	$0.91	$13.56	$12.23	$3.17	$36.56	$13.56	$1.13	$1.02
2027	$21.09	$10.66	$1.11	$12.09	$11.99	$3.11	$36.65	$12.09	$1.33	$1.22
2028	$20.69	$10.45	$1.31	$10.29	$11.76	$3.05	$36.75	$10.29	$1.52	$1.42
2029	$20.26	$10.24	$1.49	$9.89	$11.52	$2.99	$36.80	$9.89	$1.71	$1.60
2030	$19.88	$10.04	$1.67	$22.47	$11.30	$2.93	$36.89	$22.24	$1.88	$1.78
2031	$19.48	$9.84	$1.85	$22.02	$11.07	$2.87	$36.94	$22.02	$2.05	$1.95
2032	$19.10	$9.65	$2.01	$21.62	$10.85	$2.81	$37.03	$21.62	$2.21	$2.11
2033	$18.72	$9.46	$2.17	$7.34	$10.64	$2.76	$37.11	$7.34	$2.36	$2.27
2034	$18.36	$9.28	$2.32	$9.45	$10.44	$2.71	$37.21	$9.45	$2.51	$2.42
2035	$18.00	$9.10	$2.46	$12.67	$10.23	$2.65	$37.31	$12.67	$2.65	$2.56
Levelized (2021-2035)	**$20.24**	**$10.54**	**$1.36**	**$16.45**	**$11.74**	**$3.07**	**$36.70**	**$16.40**	**$1.58**	**$1.47**

Notes: Connecticut Class I supply can be counted toward compliance with Class II requirements. Vermont Tier II supply can be counted toward compliance with Tier I requirements.

7.3. Avoided RPS compliance cost per MWh reduction

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 regulation. In other words:

Equation 1. RPS Compliance Costs

$$\frac{\sum_{n} P_{n,i} \times R_{n,i}}{1-l}$$

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 9 percent)

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

Comparing results across counterfactuals

Avoided REC prices, and the resulting avoided cost of RPS compliance, are a function of supply and demand dynamics. These dynamics include both policy evolution (i.e., changes to legislation and regulation over time) and market participant behavior (e.g., LSE decisions related to RPS compliance banking, generator decisions related to operations, etc.). The below results differ across counterfactuals based on the relationship between renewable energy buildouts (largely driven by policy), load (driven by both behavior and energy efficiency and electrification assumptions), and REC price. As such, the avoided cost of RPS compliance may vary between counterfactuals as a result of differences in modeled load even when renewable energy buildouts are the same.

Counterfactual #1 results

Table 64 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 65 and Table 66 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 64. Avoided cost of RPS compliance for Counterfactual #1 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$6.59	$6.92	$5.61	$2.66	$14.96	$1.34
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.05	$5.44	$0.03	$2.56
Total	**$7.93**	**$7.37**	**$11.81**	**$8.10**	**$14.99**	**$3.90**

Table 65. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$9.73	$2.36	$1.18	$0.01	$7.57	$1.30	$1.45
2022	$10.10	$4.38	$3.50	$0.02	$6.38	$1.05	$2.13
2023	$8.54	$3.48	$3.83	$0.03	$5.81	$0.00	$2.79
2024	$6.40	$2.28	$3.43	$0.04	$4.73	$0.00	$2.91
2025	$4.47	$1.64	$3.12	$0.05	$3.65	$0.00	$3.03
2026	$4.73	$1.54	$3.53	$0.06	$4.01	$0.00	$3.79
2027	$4.48	$1.32	$3.57	$0.07	$3.55	$0.00	$5.13
2028	$4.04	$1.13	$3.51	$0.08	$3.31	$0.00	$5.36
2029	$4.09	$1.10	$3.85	$0.08	$3.43	$0.00	$5.52
2030	$9.93	$2.50	$9.98	$0.09	$9.96	$0.00	$5.65
2031	$9.60	$2.43	$9.71	$0.09	$9.89	$0.00	$5.73
2032	$9.43	$2.36	$9.43	$0.09	$9.90	$0.00	$4.37
2033	$3.20	$1.00	$3.98	$0.09	$2.47	$0.00	$4.25
2034	$4.12	$1.21	$4.86	$0.08	$3.67	$0.00	$4.10
2035	$5.52	$1.43	$5.74	$0.08	$5.92	$0.00	$3.91
Levelized (2021-2035)	**$6.59**	**$2.03**	**$4.83**	**$0.06**	**$5.61**	**$0.17**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$6.28	$2.49	$0.40	$10.33	$2.04	$1.59
2022	$0.26	$5.39	$2.64	$0.35	$13.29	$1.75	$1.81
2023	$0.27	$5.27	$2.80	$0.28	$17.50	$1.57	$2.04
2024	$0.28	$3.22	$2.67	$0.18	$9.82	$1.19	$1.52
2025	$0.28	$1.49	$2.53	$0.12	$7.68	$0.88	$1.11
2026	$0.29	$1.29	$2.24	$0.12	$10.50	$0.92	$1.15
2027	$0.29	$1.18	$1.97	$0.09	$13.93	$0.78	$0.96
2028	$0.30	$0.95	$1.74	$0.07	$13.72	$0.70	$0.86
2029	$0.30	$0.86	$1.54	$0.07	$14.65	$0.72	$0.88
2030	$0.31	$3.74	$1.36	$0.20	$24.46	$2.19	$2.66
2031	$0.31	$3.64	$1.20	$0.19	$23.79	$2.27	$2.73
2032	$0.32	$3.54	$1.05	$0.19	$23.10	$2.36	$2.83
2033	$0.32	$0.64	$0.93	$0.05	$12.35	$0.57	$0.69
2034	$0.32	$0.81	$0.82	$0.07	$14.35	$0.83	$1.00
2035	$0.33	$0.99	$0.73	$0.11	$16.09	$1.31	$1.58
Levelized (2021-2035)	**$0.30**	**$2.66**	**$1.80**	**$0.17**	**$14.96**	**$1.34**	**$1.56**

Table 66. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.18	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$3.14	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$3.16	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.82	$0.49	$0.72	$3.17	$0.34	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.54	$0.48	$0.71	$3.18	$0.22	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.53	$0.47	$0.69	$3.19	$0.22	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.47	$0.46	$0.68	$3.20	$0.20	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.40	$0.45	$0.66	$3.20	$0.17	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.39	$0.44	$0.65	$3.21	$0.16	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.88	$0.43	$0.64	$3.22	$0.36	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.86	$0.42	$0.63	$3.22	$0.36	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.85	$0.41	$0.61	$3.23	$0.35	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.29	$0.41	$0.60	$3.24	$0.12	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.37	$0.40	$0.59	$3.25	$0.15	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.50	$0.39	$0.58	$3.25	$0.21	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.64**	**$0.45**	**$0.67**	**$3.20**	**$0.27**	**$0.03**	**$1.00**

Counterfactual #2 results

Table 67 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 68 and Table 69 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 67. Avoided cost of RPS compliance for Counterfactual #2 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$3.43	$3.10	$3.10	$1.31	$5.62	$0.75
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$1.80	$5.11	$0.03	$1.93
Total	**$4.77**	**$3.55**	**$9.04**	**$6.41**	**$5.66**	**$2.67**

Table 68. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$8.95	$0.96	$0.48	$0.01	$5.02	$1.29	$1.45
2022	$5.90	$2.46	$1.97	$0.02	$3.58	$0.98	$2.13
2023	$6.60	$2.54	$2.79	$0.03	$4.32	$0.00	$2.79
2024	$3.94	$1.36	$2.04	$0.04	$3.13	$0.00	$2.91
2025	$3.98	$1.32	$2.51	$0.05	$3.30	$0.00	$3.03
2026	$0.63	$1.09	$2.50	$0.06	$3.04	$0.00	$3.79
2027	$2.92	$0.87	$2.35	$0.07	$2.99	$0.00	$5.13
2028	$2.39	$0.75	$2.33	$0.08	$2.46	$0.00	$5.36
2029	$2.20	$0.63	$2.21	$0.08	$2.29	$0.00	$5.52
2030	$1.92	$0.47	$1.89	$0.09	$2.07	$0.00	$5.65
2031	$1.75	$0.38	$1.53	$0.09	$2.03	$0.00	$5.73
2032	$1.88	$0.37	$1.49	$0.09	$2.30	$0.00	$4.37
2033	$2.23	$0.44	$1.75	$0.09	$2.86	$0.00	$4.25
2034	$2.69	$0.55	$2.19	$0.08	$3.57	$0.00	$4.10
2035	$2.66	$0.61	$2.44	$0.08	$3.37	$0.00	$3.91
Levelized (2021-2035)	**$3.43**	**$1.00**	**$2.03**	**$0.06**	**$3.10**	**$0.16**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$4.54	$2.49	$0.32	$6.17	$1.35	$1.59
2022	$0.26	$3.02	$2.64	$0.20	$6.06	$0.98	$1.31
2023	$0.27	$3.35	$2.80	$0.20	$8.59	$1.17	$1.52
2024	$0.28	$1.12	$2.67	$0.12	$6.13	$0.79	$1.01
2025	$0.28	$1.02	$2.53	$0.11	$7.57	$0.80	$1.01
2026	$0.29	$0.81	$2.24	$0.09	$7.61	$0.70	$0.87
2027	$0.29	$0.61	$1.97	$0.08	$5.58	$0.65	$0.81
2028	$0.30	$0.57	$1.74	$0.06	$4.79	$0.52	$0.64
2029	$0.30	$0.57	$1.54	$0.05	$4.90	$0.48	$0.59
2030	$0.31	$0.54	$1.36	$0.04	$4.21	$0.46	$0.55
2031	$0.31	$0.51	$1.20	$0.04	$3.72	$0.47	$0.56
2032	$0.32	$0.49	$1.05	$0.04	$4.01	$0.55	$0.66
2033	$0.32	$0.55	$0.93	$0.05	$4.43	$0.66	$0.80
2034	$0.32	$0.65	$0.82	$0.07	$4.86	$0.81	$0.97
2035	$0.33	$0.75	$0.73	$0.06	$5.25	$0.75	$0.90
Levelized (2021-2035)	**$0.30**	**$1.31**	**$1.80**	**$0.10**	**$5.62**	**$0.75**	**$0.93**

Table 69. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.13	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$1.97	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$2.03	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.51	$0.49	$0.72	$3.17	$0.21	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.48	$0.48	$0.71	$3.18	$0.20	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.07	$0.47	$0.69	$3.19	$0.03	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.31	$0.46	$0.68	$3.20	$0.13	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.24	$0.45	$0.66	$3.20	$0.10	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.21	$0.44	$0.65	$3.21	$0.09	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.17	$0.43	$0.64	$3.22	$0.07	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.16	$0.42	$0.63	$3.22	$0.07	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.17	$0.41	$0.61	$3.23	$0.07	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.20	$0.41	$0.60	$3.24	$0.08	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.24	$0.40	$0.59	$3.25	$0.10	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.24	$0.39	$0.58	$3.25	$0.10	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.39**	**$0.45**	**$0.67**	**$3.04**	**$0.16**	**$0.03**	**$1.00**

Counterfactual #3 results

Table 70 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 71 and Table 72 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 70. Avoided cost of RPS compliance for Counterfactual #3 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

Table 71. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$9.46	$2.36	$1.18	$0.01	$6.81	$1.30	$1.45
2022	$10.10	$4.38	$3.50	$0.02	$6.38	$1.05	$2.13
2023	$8.56	$3.55	$3.90	$0.03	$5.82	$0.00	$2.79
2024	$7.04	$2.52	$3.77	$0.04	$5.21	$0.00	$2.91
2025	$4.55	$1.68	$3.20	$0.05	$3.67	$0.00	$3.03
2026	$4.67	$1.50	$3.45	$0.06	$4.03	$0.00	$3.79
2027	$4.26	$1.37	$3.70	$0.07	$2.94	$0.00	$5.13
2028	$3.83	$1.25	$3.87	$0.08	$2.70	$0.00	$5.36
2029	$3.86	$1.21	$4.24	$0.08	$2.63	$0.00	$5.52
2030	$9.80	$2.50	$9.98	$0.09	$9.88	$0.00	$5.65
2031	$9.63	$2.43	$9.71	$0.09	$9.91	$0.00	$5.73
2032	$8.85	$2.36	$9.43	$0.09	$9.72	$0.00	$4.37
2033	$7.56	$1.89	$7.56	$0.09	$8.13	$0.00	$4.25
2034	$9.18	$2.30	$9.18	$0.08	$10.10	$0.00	$4.10
2035	$11.33	$2.81	$11.25	$0.08	$12.94	$0.00	$3.91
Levelized (2021-2035)	**$7.50**	**$2.28**	**$5.77**	**$0.06**	**$6.66**	**$0.17**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$5.61	$2.49	$0.40	$9.31	$1.84	$1.59
2022	$0.26	$5.39	$2.64	$0.35	$13.29	$1.75	$1.81
2023	$0.27	$5.37	$2.80	$0.28	$17.53	$1.57	$2.04
2024	$0.28	$3.55	$2.67	$0.20	$10.82	$1.31	$1.68
2025	$0.28	$1.51	$2.53	$0.12	$8.00	$0.88	$1.12
2026	$0.29	$1.32	$2.24	$0.12	$9.98	$0.93	$1.16
2027	$0.29	$1.27	$1.97	$0.07	$14.83	$0.64	$0.79
2028	$0.30	$1.06	$1.74	$0.06	$14.03	$0.57	$0.70
2029	$0.30	$0.97	$1.54	$0.05	$15.66	$0.55	$0.67
2030	$0.31	$3.74	$1.36	$0.20	$24.45	$2.17	$2.64
2031	$0.31	$3.64	$1.20	$0.19	$23.78	$2.27	$2.74
2032	$0.32	$3.54	$1.05	$0.19	$23.10	$2.31	$2.78
2033	$0.32	$2.83	$0.93	$0.15	$18.52	$1.89	$2.27
2034	$0.32	$3.44	$0.82	$0.18	$22.50	$2.30	$2.76
2035	$0.33	$4.21	$0.73	$0.23	$28.36	$2.88	$3.45
Levelized (2021-2035)	**$0.30**	**$3.18**	**$1.80**	**$0.19**	**$16.77**	**$1.58**	**$1.86**

Table 72. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.18	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$3.14	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$3.16	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.88	$0.49	$0.72	$3.17	$0.36	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.55	$0.48	$0.71	$3.18	$0.23	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.53	$0.47	$0.69	$3.19	$0.22	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.45	$0.46	$0.68	$3.20	$0.19	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.38	$0.45	$0.66	$3.20	$0.16	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.37	$0.44	$0.65	$3.21	$0.15	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.88	$0.43	$0.64	$3.22	$0.36	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.87	$0.42	$0.63	$3.22	$0.36	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.80	$0.41	$0.61	$3.23	$0.33	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.68	$0.41	$0.60	$3.24	$0.28	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.83	$0.40	$0.59	$3.25	$0.34	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.88	$0.39	$0.58	$3.25	$0.36	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.72**	**$0.45**	**$0.67**	**$3.20**	**$0.30**	**$0.03**	**$1.00**

Counterfactual #4 results

Table 73 shows the avoided cost of RPS compliance aggregated for all new and other categories. Table 74 and Table 75 provide additional detail, and display the avoided cost of RPS compliance, by year and by category, for both New and Existing RPS programs. All levelized values are 15-year levelized values.

Table 73. Avoided cost of RPS compliance for Counterfactual #3 (2021 $ per MWh)

	CT	ME	MA	NH	RI	VT
Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
MA CES & CPS	-	-	$4.14	-	-	-
All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**

Table 74. Summary of avoided cost of RPS compliance, New RPS categories (2021 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2021	$9.46	$2.36	$1.18	$0.01	$6.81	$1.30	$1.45
2022	$10.10	$4.38	$3.50	$0.02	$6.38	$1.05	$2.13
2023	$8.56	$3.55	$3.90	$0.03	$5.82	$0.00	$2.79
2024	$7.04	$2.52	$3.77	$0.04	$5.21	$0.00	$2.91
2025	$4.55	$1.68	$3.20	$0.05	$3.67	$0.00	$3.03
2026	$4.67	$1.50	$3.45	$0.06	$4.03	$0.00	$3.79
2027	$4.26	$1.37	$3.70	$0.07	$2.94	$0.00	$5.13
2028	$3.83	$1.25	$3.87	$0.08	$2.70	$0.00	$5.36
2029	$3.86	$1.21	$4.24	$0.08	$2.63	$0.00	$5.52
2030	$9.80	$2.50	$9.98	$0.09	$9.88	$0.00	$5.65
2031	$9.63	$2.43	$9.71	$0.09	$9.91	$0.00	$5.73
2032	$8.85	$2.36	$9.43	$0.09	$9.72	$0.00	$4.37
2033	$7.56	$1.89	$7.56	$0.09	$8.13	$0.00	$4.25
2034	$9.18	$2.30	$9.18	$0.08	$10.10	$0.00	$4.10
2035	$11.33	$2.81	$11.25	$0.08	$12.94	$0.00	$3.91
Levelized (2021-2035)	**$7.50**	**$2.28**	**$5.77**	**$0.06**	**$6.66**	**$0.17**	**$3.98**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2021	$0.26	$5.61	$2.49	$0.40	$9.31	$1.84	$1.59
2022	$0.26	$5.39	$2.64	$0.35	$13.29	$1.75	$1.81
2023	$0.27	$5.37	$2.80	$0.28	$17.53	$1.57	$2.04
2024	$0.28	$3.55	$2.67	$0.20	$10.82	$1.31	$1.68
2025	$0.28	$1.51	$2.53	$0.12	$8.00	$0.88	$1.12
2026	$0.29	$1.32	$2.24	$0.12	$9.98	$0.93	$1.16
2027	$0.29	$1.27	$1.97	$0.07	$14.83	$0.64	$0.79
2028	$0.30	$1.06	$1.74	$0.06	$14.03	$0.57	$0.70
2029	$0.30	$0.97	$1.54	$0.05	$15.66	$0.55	$0.67
2030	$0.31	$3.74	$1.36	$0.20	$24.45	$2.17	$2.64
2031	$0.31	$3.64	$1.20	$0.19	$23.78	$2.27	$2.74
2032	$0.32	$3.54	$1.05	$0.19	$23.10	$2.31	$2.78
2033	$0.32	$2.83	$0.93	$0.15	$18.52	$1.89	$2.27
2034	$0.32	$3.44	$0.82	$0.18	$22.50	$2.30	$2.76
2035	$0.33	$4.21	$0.73	$0.23	$28.36	$2.88	$3.45
Levelized (2021-2035)	**$0.30**	**$3.18**	**$1.80**	**$0.19**	**$16.77**	**$1.58**	**$1.86**

Table 75. Summary of avoided cost of RPS compliance, Existing RPS categories (2021 $ per MWh)

	CT-II	CT-III	ME-II	MA-II RE	MA-II WTE	MA CES-E	NH-III	NH-IV	RI-Existing	VT-I
2021	$0.89	$0.52	$0.25	$0.91	$0.46	$0.76	$3.18	$0.38	$0.02	$0.53
2022	$0.88	$0.51	$0.24	$0.88	$0.50	$0.75	$3.14	$0.36	$0.02	$0.51
2023	$0.90	$0.50	$0.24	$0.88	$0.49	$0.73	$3.16	$0.36	$0.02	$0.54
2024	$0.98	$0.49	$0.23	$0.88	$0.49	$0.72	$3.17	$0.36	$0.02	$0.52
2025	$0.96	$0.48	$0.23	$0.55	$0.48	$0.71	$3.18	$0.23	$0.02	$0.50
2026	$0.94	$0.47	$0.30	$0.53	$0.47	$0.69	$3.19	$0.22	$0.02	$0.67
2027	$0.92	$0.46	$0.36	$0.45	$0.46	$0.68	$3.20	$0.19	$0.03	$0.80
2028	$0.90	$0.46	$0.43	$0.38	$0.45	$0.66	$3.20	$0.16	$0.03	$0.92
2029	$0.88	$0.45	$0.49	$0.37	$0.44	$0.65	$3.21	$0.15	$0.04	$1.09
2030	$0.87	$0.44	$0.55	$0.88	$0.43	$0.64	$3.22	$0.36	$0.04	$1.21
2031	$0.85	$0.43	$0.60	$0.87	$0.42	$0.63	$3.22	$0.36	$0.04	$1.31
2032	$0.83	$0.42	$0.66	$0.80	$0.41	$0.61	$3.23	$0.33	$0.05	$1.50
2033	$0.82	$0.41	$0.71	$0.68	$0.41	$0.60	$3.24	$0.28	$0.05	$1.61
2034	$0.80	$0.40	$0.76	$0.83	$0.40	$0.59	$3.25	$0.34	$0.05	$1.71
2035	$0.78	$0.40	$0.81	$0.88	$0.39	$0.58	$3.25	$0.36	$0.06	$1.81
Levelized	**$0.88**	**$0.46**	**$0.45**	**$0.72**	**$0.45**	**$0.67**	**$3.20**	**$0.30**	**$0.03**	**$1.00**

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. Non-embedded costs are (by definition) not included in the AESC 2021 modeling of avoided energy costs. In contrast, costs associated with RGGI, SO_2 regulation programs, and Massachusetts' 310 CMR 7.74 regulation are included in the AESC 2021 modeling of energy prices and thus impact the avoided energy costs in a quantifiable way (see Section 4.8: *Embedded emissions regulations* for a discussion of how these costs are modeled).

For the AESC 2021 Study, we estimate values for some of the principal non-embedded environmental costs. Here we address two such categories: the non-embedded portion of GHG impacts, and the costs of NO_X emissions.

Because different states participating in the AESC study have differing policy contexts, we offer several different options and approaches for calculating the non-embedded GHG cost. AESC 2021 provides these approaches to enable individual states to address specific policy directives regarding GHG impacts. Table 76 and Table 77 compares these four values to values described in AESC 2018.

- A "damage cost" approximated by the social cost of carbon (SCC). There are many different options for a social cost of carbon. The Synapse Team recommends using a value that applies low discount rates, considers global damages, and considers the impact of high-risk situations. One source for this value is the December 2020 SCC Guidance published by the State of New York. Using a 2 percent discount rate (the one also recommended by New York for most decision-making), we recommend a 15-year levelized SCC of $128 per short ton in AESC 2021. We also recommend that program administrators continually review this value (e.g., for the purposes of mid-term modifications), as updates to the federally-recommended SCC are expected in early 2022.

- An approach based on global marginal abatement costs. In AESC 2021, we estimate a total environmental cost based on the cost of large-scale CCS equal to $92 per short ton of CO_2-eq. This is lower than the $105 per short ton of CO_2-eq value (in 2021 dollars) described in AESC 2018. This lower cost reflects the declining costs of this technology.

- An approach based on New England marginal abatement costs, assuming a cost derived from electric sector technologies. In AESC 2021, this is a total environmental cost of $125 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for offshore wind energy along the eastern seaboard. This compares to a cost of $72 per short ton of CO_2-eq emissions (in 2021 dollars) based on a projection of future costs of offshore wind energy, as described in AESC 2018. This increased cost reflects updated information on this technology in the United States, as well as lower energy costs in this edition of AESC.

- An approach based on New England marginal abatement costs, assuming a cost derived from multiple sectors. In AESC 2021, this is a total environmental cost of $493 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for RNG derived from power-to-gas technology. This approach may be useful for policymakers who are considering more ambitious carbon reduction targets (e.g., 90 percent or 100 percent reductions by 2050).

Table 76. Comparison of GHG costs under different approaches (2021 $ per short ton) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	$128	-	-
Global marginal abatement cost	$105	$92	-$13	-12%
New England-based marginal abatement cost, derived from the electric sector	$72	$125	$53	75%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	$493	-	-

Notes: All values shown are levelized over 15 years. All AESC 2021 values except the SCC are levelized using a 0.81 percent discount rate (SCC uses a 2.0 percent discount rate). All AESC 2018 values are levelized using a 1.34 percent discount rate, then converted into 2021 dollars. In AESC 2018, damage costs were discussed, but not quantified. AESC 2018 did not discuss or estimate a New England-based marginal abatement cost derived from multiple sectors. Values shown above remove energy prices, but not embedded costs. Values shown above do not include losses.

Table 77. Comparison of GHG costs under different approaches (2021 cents per kWh) in Counterfactual #1

	AESC 2018	AESC 2021	Difference	% Difference
Social cost of carbon (SCC or "damage cost") at 2% discount rate	Not quantified	4.87	-	-
Global marginal abatement cost	4.64	3.41	-1.23	-26%
New England-based marginal abatement cost, derived from the electric sector	2.83	4.74	1.91	67%
New England-based marginal abatement cost, derived from multiple sectors	Not calculated	19.72	-	-

Notes: Values shown above remove embedded costs (e.g., RGGI, MA 310 7.74, MA 310 7.75. All values are quoted using a summer on-peak seasonal marginal emission rate, and include a 9 percent energy loss factor.

AESC users may wish to include a non-embedded cost to fully account for the cost of GHG impacts or GHG abatement. In order to do this, users 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 relevant GHG emission cost to determine the remaining cost that is non-embedded. 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 2021. We find a non-embedded NO_X emission cost of $14,700 per short ton of NO_X, based on a review of findings in the literature.

See Appendix B: *Detailed Electric Outputs* and Appendix G: *Marginal Emission Rates and Non-embedded Environmental Cost Detail* for more detail on this topic.

8.1. Non-embedded GHG costs

Costs of GHG emissions are partially embedded in prices through RGGI allowances, state regulations such as 310 CMR 7.74 and 310 CMR 7.75 in Massachusetts, 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. Because different states participating in the AESC study have differing policy contexts, we offer several different options and approaches for calculating the non-embedded GHG cost. Because of the time horizon of modeling in AESC 2021, our costs are focused on the likely costs expected in the timeframe of 2021 through 2035.

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.)

Social cost of carbon (damage cost)

The SCC attempts to monetize the current and future damages resulting from CO_2 emissions.[190] Policymakers can use this value to assess policies that address climate change. Developing a reasonable value for the SCC can be a complex endeavor. This section describes the SCC promulgated and used by the U.S. federal government, as well as SCC studies and guidelines by other parties. This section closes with an SCC recommendation for users of AESC.

Federal agency consideration of the SCC

In a series of analyses beginning in 2009, the Obama Administration convened an Interagency Working Group (IWG) to develop a recommendation for an SCC value to use in decision-making by federal agencies. The revised technical support document published in August 2016 relies on outputs from three different integrated assessment models (IAM) to develop sets of SCC values.[191] These different sets of values vary according to the discount rate used (i.e., how heavily future damages are discounted) and whether or not they include lower-probability, higher-impact values. The Obama Administration issued a central recommendation of a 3 percent discount rate, without the inclusion of higher-impact values. This yields an SCC value of $49 per short ton of CO_2 in 2021, (in 2021 dollars). These values escalate over time; by 2050, these values are 1.7 times larger than the 2020 values, in real-dollar terms.

[190] In most contexts, the SCC is recommended to also be applied to other GHGs (e.g., methane, nitrous oxides). In these situations, the SCC is converted using a series of calculations that seek to estimate the equivalent impacts of disparate GHGs. For purposes of simplification, this text makes reference to "SCC" only, although this value should appropriately be converted and applied to other GHG emissions as necessary.

[191] Interagency Working Group on Social Cost of Greenhouse Gases. August 2016. *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866.* Available at https://obamawhitehouse.archives.gov/sites/default/files/omb/inforeg/scc_tsd_final_clean_8_26_16.pdf.

In 2017, the Trump Administration issued guidance to update the SCC estimate that only included domestic impacts of carbon emissions and to recommend discount rates from 3 to 7 percent. At the lower bound of 3 percent, the Trump Administration estimated the SCC to be $7 per short ton of carbon dioxide in 2020 (in 2021 dollars). This value is just one-seventh of the Obama Administration's estimate. At a discount rate of 7 percent, the Trump Administration found an SCC of $1 per short ton of carbon dioxide in 2020 (in 2021 dollars).[192] The issue with measuring only domestic damages of carbon, however, is that the emissions quickly spread on a global scale and contribute to climate change impacts around the world. Moreover, high discount rates such as 7 percent are a way to reflect returns on capital, rather than climate change impacts for future generations.[193]

In February 2021, the Biden Administration issued its draft guidance for the SCC.[194] The draft guidance rescinds the 2019 draft GHG guidance issued by the Trump Administration, effectively rejecting the 7 percent discount rate and the notion that climate change damages caused by U.S. emissions but suffered in other countries should be ignored. The Biden Administration has stated that it intends to re-convene the IWG, re-estimate the SCC, and re-issue new guidance on a federal SCC in January 2022. We should anticipate that the update will reflect recent information and analysis of climate impacts, valuation of damages, and discounting. The February 2021 guidance states that, "[I]n the interim, agencies should consider all available tools and resources in assessing GHG emissions and climate change effects of their proposed actions, including, as appropriate and relevant, the 2016 GHG Guidance."[195]

Other SCC recommendations

The federal IWG SCC is one among many SCC calculations. Some other calculations of the SCC use one of the identical models used by the IWG, but update key parameters.[196] Yet other calculations of the SCC utilize different models and also take low-probability but higher-impact costs into account (see, for

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[192] U.S. Government Accountability Office. June 2020. *Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis.* Available at https://www.gao.gov/assets/gao-20-254.pdf. See Page 57, Table 10.

[193] U.S. Government Accountability Office. June 2020. *Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis.* Available at https://www.gao.gov/assets/gao-20-254.pdf. See Page 32.

[194] Council on Environmental Quality. February 19, 2021. "National Environmental Policy Act Guidance on Consideration of Greenhouse Gas Emissions." *Federalregister.gov.* Available at https://www.federalregister.gov/documents/2021/02/19/2021-03355/national-environmental-policy-act-guidance-on-consideration-of-greenhouse-gas-emissions.

[195] Executive Office of the President. January 20, 2021. "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." *Federalregister.gov.* Available at https://www.federalregister.gov/documents/2021/01/25/2021-01765/protecting-public-health-and-the-environment-and-restoring-science-to-tackle-the-climate-crisis.

[196] Nordhaus, W.D. 2017. "Revisiting the social cost of carbon." *Proceedings of the National Academy of Sciences,* 114 (7) 1518-1523; DOI: 10.1073/pnas.1609244114. https://doi.org/10.1073/pnas.1609244114 and Hansel, C. M. et al. 2020. "Climate economics support for the UN climate targets." *Nature Climate Change*. http://acdc2007.free.fr/hansel720.pdf.

example the 2014 meta-analysis described in AESC 2018).[197] These studies may also recommend the use of lower discount rates than those analyzed by the IWG.[198] While high discount rates may be useful in contexts relating to financial rates of return, lower discount rates are thought to be more ethically compatible with preserving the planet for future generations of humanity, and thus more appropriate for an SCC. Still other calculations may be derived through other means, including meta-analysis of other research.[199] Depending on the year being described and discount rate used, SCCs in these studies range from roughly \$53 to \$820 per short ton of CO_2 (in 2021 dollars). We note there are also published recommendations on the SCC that do not necessarily specify values, but instead suggest best practices for performing the calculation.[200]

Generally speaking, experts examining or calculating an SCC typically recommend using reasonable, low discount rates; evaluating the SCC with a global perspective; and including the evaluation of low-probability, high-impact events in either the "main" SCC being recommended or in separate sensitivities.

New York State Social Cost of Carbon Guideline

In December 2020, the New York State Department of Environmental Conservation released a guideline document titled "Establishing a Value of Carbon" (the NYS SCC Guideline).[201] This document provides a range of carbon values as well as guidance for state entities on which values to use. Most notably, the NYS SCC Guideline recommends using the values identified as an interim SCC by the Biden Administration in February 2021 (and previously issued by the Obama Administration in 2016), but with a different range of discount rates. We discuss this guidance document in detail due to New York's similar energy landscape and policy context to the six New England states.

The NYS SCC Guideline recommends basing the SCC on the estimations calculated by the federal IWG in 2016 and identified as interim in 2021, as these use a global scope of emissions impacts and estimate impacts through the year 2300. As described above, the federal IWG uses an average SCC from three different IAMs models to provide robustness to the final calculation. The NYS SCC Guideline also recommends that the full scope of impacts of all relevant GHGs (e.g., methane, nitrous oxide) should be considered, not just CO_2. This is necessary to ensure that reducing one type of emissions does not transfer the pollution to another emission or jurisdiction. Similarly, the NYS SCC Guideline explains the

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[197] 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

[198] Stern, N., and J. E. Stiglitz. 2021. "The Social Cost of Carbon, Risk, Distribution, Market Failures: An Alternative Approach." NBER Working Paper Series. http://www.nber.org/papers/w28472

[199] Richard S J Tol, 2018. "The Economic Impacts of Climate Change." *Review of Environmental Economics and Policy*, Volume 12, Issue 1, Pages 4–25, https://doi.org/10.1093/reep/rex027. Also available at https://academic.oup.com/reep/article/12/1/4/4804315#110883856.

[200] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651.

[201] New York State Department of Environmental Conservation. 2020. *Establishing a Value of Carbon: Guidelines for Use by State Agencies.* Available at: https://www.dec.ny.gov/docs/administration_pdf/vocfguid.pdf

necessity of considering the global impact of emissions, as carbon impacts are not localized. Furthermore, the NYS SCC Guideline recommends staying up-to-date with peer-reviewed literature related to the SCC to ensure the most accurate cost estimates. Finally, the NYS SCC Guideline encourages the use of an appropriate discount rate, different from the range in the IWG document.

While the federal IWG provides SCC values using discount rates of 2.5 percent, 3 percent, and 5 percent (with a "central" identified value of 3 percent) the NYS SCC Guideline recommends calculating the SCC at a discount rate of 1 percent, 2 percent, and 3 percent to understand the range of potential SCC values.[202] In particular, the NYS SCC Guideline also recommends using a central discount rate of no more than 2 percent for decision-making. The NYS SCC Guideline recommends relying on the central discount rate of 2 percent or less for several reasons:

- First, higher discount rates are more appropriate for evaluating private investments, while the issues here are about long-term impacts to the public from global climate change.
- Second, the NYS SCC Guideline points out that recent research has found that the federal IWG underestimates the value of avoiding emissions damages (see discussion above on other estimates of the SCC that utilize the same methodology as the IWG, but update key input parameters). The NYS SCC Guideline notes that the federal IWG estimates do not fully account for damages from high-impact events or climatic tipping points, and that these damages could be accounted for through the use of lower discount rates.
- Third, the NYS SCC Guideline does not recommend using a discount rate of 0 percent at this time. A discount rate of 0 percent values the present and future equally, which is potentially not representative of how society values the present and future.
- Fourth, the NYS SCC Guideline notes that, "Experts now generally consider a range of 1–3 percent to be more acceptable." A 2 percent discount rate is the central value of this range.

As a result, the NYS SCC Guideline recommends a discount rate of no more than 2 percent, as this will best account for public safety and welfare and significant environmental impacts, while recognizing some difference in societal value between the present and the long-term future. The NYS SCC Guideline notes that "[a]dditional approaches such as declining discount rates and providing estimates at the 95th percentile of the central value could also be considered by the Department in the future as more review and refinement of the estimates occur." Accordingly, the NYS SCC Guideline recommends an SCC of

[202] It is theoretically possible to calculate an SCC using any discount rate, rather than the ones enumerated here. However, the application of discount rates in the SCC calculation happens fairly early in the methodology, meaning that users of the SCC are limited to the use of the SCCs calculated using the published discount rates.

$116 per short ton of CO_2 at a 2 percent discount rate (in 2021 dollars), escalating over time.[203] On a 15-year levelized basis, this SCC is equal to $128 per short ton of CO_2.

Recommendation for AESC 2021

Table 78 summarizes the NYS SCC Guideline values across time and provides a levelized 15-year value for each of the three series. We recommend that users of AESC rely on the SCC values shown in the column based on the 2 percent discount rate, with SCC values ranging from $116 (in 2020) to $165 (in 2050) in 2021 dollars per short ton of CO_2, and a 15-year levelized value of $128 per short ton. We recommend the use of a central value of 2 percent for the discount rate in line with the NYS SCC Guideline. This SCC value is likely to be suitable for use in New England states that consider the social cost of GHGs in cost-effectiveness planning, since the New England states are similar to New York in terms of energy landscape and policy context. Moreover, the NYS SCC Guideline values consider the global impact of emissions, use reasonable discount rates, and consider high-impact events through low discount rates. Analyses since the August 2016 IWG report support expectations of greater damages from climate change and the use of lower discount rates. For example, a survey of approximately 200 experts found a mean recommended social discount rate (SDR) of 2 percent, and that "[m]ore than 90 percent are comfortable with a SDR somewhere in the interval of 1 percent to 3 percent."[204]

Note that the discount rate we recommend for the SCC is different than the discount rate used elsewhere in AESC. For the SCC, we recommend the use of a 2 percent discount rate, as this discount rate is based in part on an ethical consideration of the value of future generations of humanity, rather than derived from observations in the financial markets (such as treasury bill rates or utility rates of return, which are largely unrelated to considerations important to the SCC).[205] Other values described in Table 78 may be useful to examine in sensitivity testing of program or measure cost-effectiveness.

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[203] New York State Department of Environmental Conservation. 2020. *Appendix: Value of Carbon.* Available at: https://www.dec.ny.gov/docs/administration_pdf/vocfapp.pdf. Values were originally reported in 2020 dollars per metric ton; here, they have been converted into 2021 dollars per short ton using AESC 2021's deflator.

[204] Drupp, M.A., M.C. Freeman, B. Groom, F. Nesje. 2018. "Discounting Disentangled." *American Economic Journal: Economic Policy*, November, page 33.

[205] We note that the original 2003 methodology used to calculate a 3 percent discount rate involved subtracting the 30-year average of year-on-year CPI changes (1973 through 2002) from the 30-year average of 10-year U.S. Treasury yields (1973 through 2002). Using the data currently available from the U.S. Treasury and the Bureau of Labor Statistics, we calculate an implied discount rate of 3.01 percent, which rounds to 3 percent. When this same methodology is applied to a more recent 30-year period spanning 1991 through 2020, we calculate an implied discount rate of 2.02 percent, which rounds to 2 percent. In short, even if one were to rely exclusively on financial markets to determine an appropriate discount rate for the social cost of carbon, it would be appropriate to use a 2 percent discount rate rather than a 3 percent discount rate.

Obama White House Archives. Last accessed March 11, 2021. "Circular A-4." Obamawhitehouse.org. Available at https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/.

U.S. Department of Treasury. Last accessed March, 11. 2021. "Daily Treasury Yield Curve Rates." *Treasury.gov.* Available at https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield.

U.S. Bureau of Land Statistics. Last accessed March 11, 2021. "Historical Consumer Price Index for All Urban Consumers." *Bls.gov.* Available at https://www.bls.gov/cpi/tables/supplemental-files/historical-cpi-u-202101.pdf.

Importantly, we note that this is the recommendation being made by the AESC authors at the time of this report's writing. It is possible—even likely—that this value will change as new information becomes available. Such new information may include new data on high-impact events and climate change risks and feedbacks, information about time preference and discount rates, updated model input parameters, or other factors. This information may be promulgated by the federal government in the course of the Biden Administration's final SCC rulemaking, due to be released in January 2022, or from independent assessments published by various third parties. We recommend that program administrators continually review this value and potentially revisit an update to this value for mid-term modification purposes in early 2022.

Whenever possible, we also recommend considering the full scope of emissions impacts and the effect on non-carbon emissions to ensure one pollutant is not replaced by another.

Table 78. Comparison of social costs of carbon at varying discount rates from NYS SCC Guideline and federal IWG (2021 dollars per short ton)

	3.0%	2.0%	1.0%
2020	$49	$116	$390
2021	$49	$118	$391
2022	$51	$119	$394
2023	$52	$120	$396
2024	$53	$122	$399
2025	$55	$124	$401
2026	$56	$125	$403
2027	$56	$127	$405
2028	$57	$129	$408
2029	$57	$130	$410
2030	$59	$131	$413
2031	$60	$133	$415
2032	$61	$135	$416
2033	$62	$136	$419
2034	$64	$138	$421
2035	$65	$140	$424
2036	$66	$142	$426
2037	$68	$143	$428
2038	$68	$144	$430
2039	$69	$146	$432
2040	$70	$148	$434
2041	$72	$150	$437
2042	$72	$152	$440
2043	$73	$154	$442
2044	$74	$155	$445
2045	$75	$157	$447
2046	$77	$158	$449
2047	$78	$160	$451
2048	$79	$162	$452
2049	$81	$163	$454
2050	$81	$165	$456
15-year levelized	**$57**	**$128**	**$407**

Sources and notes: Values are obtained from https://www.dec.ny.gov/docs/administration_pdf/vocfapp.pdf. All values have been converted into 2021 dollars per short tons. Value streams are shown from lowest to highest, left to right. All levelization calculations were performed using each column's noted discount rate.

Marginal abatement costs

A second approach to pricing carbon is the marginal abatement cost method. 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 developing regional strategies for meeting those targets that may only include the deployment of certain technologies. This suggests a local perspective, identifying the marginal abatement cost on a local scenario for meeting regional emission reduction targets.

International perspective

Previous AESC studies (AESC 2013, AESC 2015, and AESC 2018) all arrived at the conclusion that CCS was the marginal abatement technology in many global scenarios for climate mitigation. These global scenarios often consider both electric and non-electric measures, meaning CCS is the marginal economy-wide technology. In AESC 2018, we determined this value had a total cost of $100 per short ton (in 2018 dollars), according to a 2015 meta-analysis of CCS costs.[206] The latest data assembled by NREL in its 2020 release of the ATB suggests this number has decreased since that study took place.[207] According to this study, a natural gas combined cycle (NGCC) power plant running at an average capacity factor built with CCS has an incremental cost of $29 per MWh versus a standard NGCC running at the same capacity factor (in 2018 dollars). Under this report's assumptions, a CCS system is capable of avoiding 90 percent of carbon emissions, producing an avoided emissions rate of 0.33 short tons per MWh. Dividing $29 per MWh by 0.33 short tons per MWh yields an incremental cost of $88 per short ton (in 2018 dollars). In 2021 dollars, this is a cost of $92 per short ton. This is our international perspective estimate.

Local perspective

AESC 2021 proposes two different local marginal abatement costs for New England states with different policy contexts.

[206] Edward S. Rubin, John E. Davison and Howard J. Herzog (2015), "The cost of CO_2 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 (stated as $59 - $143 per metric ton in 2013 dollars).

[207] NREL (National Renewable Energy Laboratory). 2020. 2020 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. Available at https://atb.nrel.gov/electricity/2020/data.php.

Derived from the electric sector

AESC 2018 proposed an electric-sector technology as the marginal abatement technology in New England, as it assumed that all end-uses would need to be electrified and then powered by zero- or low-carbon electric-sector technologies in order to achieve substantial GHG emission reductions. In AESC 2018, we determined that the most appropriate marginal abatement technology for New England was offshore wind.

After reviewing recent literature on this topic, under the AESC counterfactual paradigm, we find that offshore wind remains the best estimate from a local perspective. Conventionally, marginal abatement technologies are identified through comparative analysis of technology costs (measured in dollars-per-ton abated) and potentials (measured in total potential tons to abate). It is expensive and challenging to define a regional marginal abatement technology for four reasons:

- First, prices of technologies change over time as technologies improve and new policies come into effect.
- Second, technology potentials change over time as new data becomes available, as technologies improve, and as new resources are constructed (thereby decreasing the amount of future emissions-reducing potential).
- Third, the "demand" for future emission reductions is not always known. Some states may have defined emission reduction goals, targets, or requirements for some years, but not all years being considered. Other states may not identify emission reduction targets for the sectors of interest to AESC, or may be ambiguous in terms of how "required" these emission reductions are.
- Finally, in an ideal world, this exercise would be performed for every year being considered for analysis. This temporal aspect complicates each of the factors described above.

Given that AESC 2021 does not have the scope or time available to perform an exhaustive marginal abatement estimate, we look to the literature. One 2019 study, relying in part on cost and potentials data assembled by the Synapse Team in AESC 2018, found that in 2030 offshore wind represents about half of the overall emissions reduction potential for Massachusetts.[208] Furthermore, if this same study were performed absent the resources being tested for cost-effectiveness with AESC 2021 (e.g., future energy efficiency or electrification), we would likely find offshore wind to be the marginal resource.[209] Because of offshore wind's large resource potential, it is likely to be the marginal resource in any

[208] Stanton, E., T. Stasio, B.Woods. 2019. *Marginal Cost of Emissions Reductions in Massachusetts.* Applied Economics Clinic for the Green Energy Consumers Alliance. Available at https://static1.squarespace.com/static/5936d98f6a4963bcd1ed94d3/t/5de5363d20783a433fff5ffe/1575302718557/Marginal+Cost+of+Emissions+Reductions+in+Massachusetts_Nov+2019.pdf.

[209] Other information may be available from a forthcoming climate policy sensitivity. See Chapter 12: *Sensitivity Analysis* for more information.

number of scenarios that test the sensitivity of marginality to variables like prices, potentials, states considered to have "required" emission reductions, and year being considered for marginality.

With this under consideration, the Synapse Team performed a review of the literature to develop an up-to-date forecast of offshore wind prices over the AESC 2021 study period. In October 2020, NREL published its *2019 Offshore Wind Technology Data Update*, which contained the levelized adjusted strike prices for over 30 different offshore wind auctions across the United States and Europe.[210] The NREL strike price refers to the contract price agreed upon by the buyer and seller of energy for a given project. This price is typically tied to a specific contract length, represents what the project will be paid for the energy and other benefits, and likely includes some profit margin for the developer. In this document, NREL has adjusted all strike prices to include grid connection and development costs in order to ensure an apples-to-apples comparison across projects. NREL has also accounted for differences in contract length by converting the annual strike price to a present value. Since this report contains strike price data for projects with estimated online dates between 2020 and 2025, we used the average cost in each year to develop our price forecast.

In order to project how the cost of offshore wind could change after 2025, we referenced NREL's most recent ATB.[211] NREL releases a new version of the ATB each year as a way to track how improvements in R&D and supply chain can affect technology costs and performance assumptions. One of the metrics provided in the ATB is the levelized cost of energy. This metric uses the projected technology cost and performance to calculate the total costs as spread out over the total anticipated energy generation. NREL's moderate technology innovation scenario projects a decrease in offshore wind's levelized cost of energy over time, largely due to increasing turbine sizes and increased efficiency in the supply chain. This year-over-year cost decline was used in conjunction with the average strike price from 2025 to develop a more forward-looking trend out through 2035.[212] Figure 45 shows the offshore wind price trajectory used to calculate the marginal abatement cost over the AESC 2021 study period. Price data for Mayflower wind was adjusted based on new information pertaining to the extended investment tax credit released in January 2021.[213]

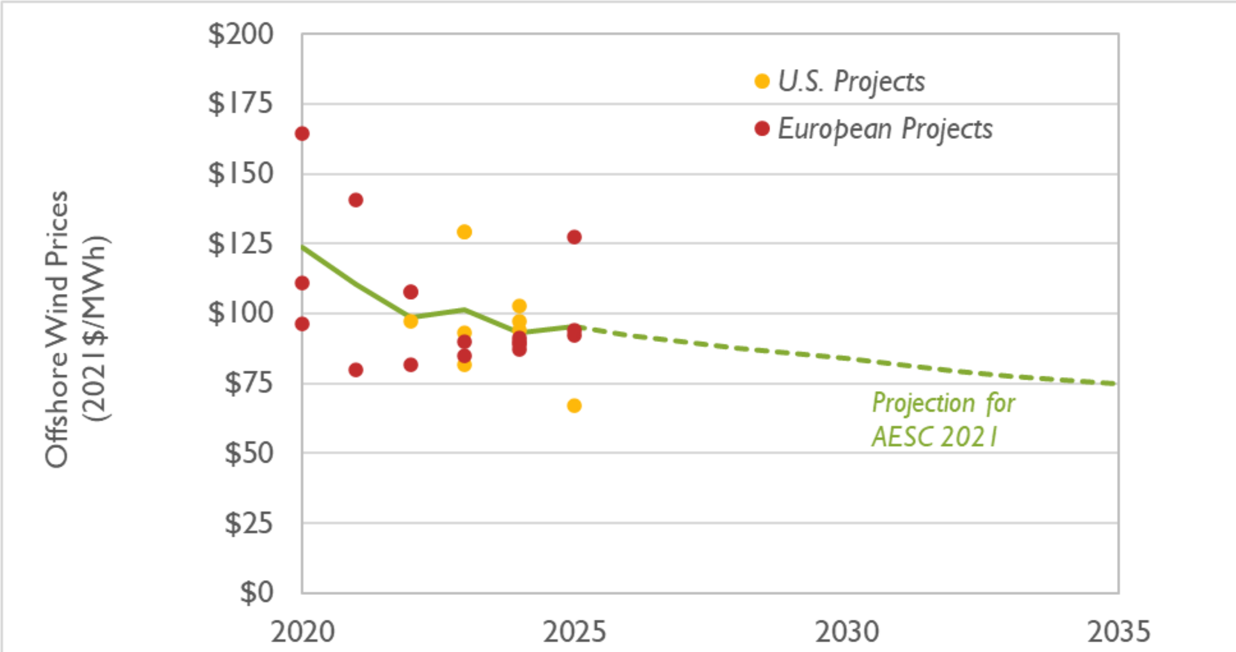
[210] NREL (National Renewable Energy Laboratory). 2020. *2019 Offshore Wind Technology Data Update.* Available at https://www.nrel.gov/docs/fy21osti/77411.pdf.

[211] NREL (National Renewable Energy Laboratory). 2020. "2020 Annual Technology Baseline." Available at: https://atb.nrel.gov/electricity/2020/about.php

[212] We referenced the levelized cost of energy trajectory that assumed the "Market + Policies" financial case, a moderate technology innovation scenario, and the default technology class. The Market + Policies case considers federal tax credits and debt interest rates. Class 3 was selected as the default technology class by NREL because it "best represents the resource characteristics of near-term deployment for fixed bottom technology". See https://atb.nrel.gov/electricity/2020/index.php?t=ow for more detail.

[213] Mayflower Wind. January 8, 2021. "Mayflower Wind "Low-Cost Energy" Price Anticipated to go Even Lower Due to Unique Commitment to Pass Cost Savings of Federal Tax Credits to Customers." *Mayflowerwind.com*. Available at https://mayflowerwind.com/mayflower-wind-low-cost-energy-price-anticipated-to-go-even-lower-due-to-unique-commitment-to-pass-cost-savings-of-federal-tax-credits-to-customers/.

Figure 45. Price trajectory for offshore wind



Sources: Data from NREL, "2019 Offshore Wind Technology Data Update" and 2020 Annual Technology Baseline. Datapoint for Mayflower Wind based on updated pricing announced in a January 8, 2021 by the project developers.

After we developed the cost trajectory using the methodology described above, we subtracted the estimated energy costs from the total offshore wind price.[214] Because the amount paid for energy represents revenue to the offshore wind project owner, only the remainder is considered the abatement cost.[215] This abatement cost represents the incremental cost of this non-emitting technology. After levelizing the abatement cost stream into a present value, the cost was multiplied by the annual marginal emissions rates of described below in Table 80. The final value translates to a cost per avoided short ton of CO_2 of $125 per short ton.

In AESC 2018, the cost of avoided CO_2 was reported to be $68 per short ton in 2018 dollars or $72 per short ton in 2021 dollars. We find that the AESC 2021 cost is 75 percent higher. This cost increase is driven by three factors:

- First, in AESC 2021, we have access to more cost data specific to U.S. projects in New Jersey, New York, Massachusetts, and Maryland. The previous AESC 2018 report primarily relied upon European prices due to a lack of U.S. data.

[214] For the calculations described in this paragraph, we have subtracted the energy costs associated with Counterfactual #1.

[215] This calculation does not remove capacity payments. These are unknown for projects that are currently proposed in New England, and given the rules of the FCM, are highly dependent on the timing of retiring power plants. This cost also does not account for any additional costs related to network upgrades or storage (e.g., for balancing purposes). If these components were included, the total cost would be higher, making the cost described above a conservative estimate.

- Second, in AESC 2021, we assume annual changes in the cost of offshore wind (e.g., costs start relatively high but decline over time). AESC 2018 assumed a single, unchanging cost throughout the study period.
- Third, the projected energy prices are lower in this edition of AESC 2021. This causes the residual cost of offshore wind to be higher, relative to AESC 2018.

Derived from multiple sectors

AESC 2018 assumed that all end-uses would need to be electrified in order to achieve substantial GHG emission reductions. However, in some policy contexts, policymakers (including utilities and program administrators) who are considering more ambitious carbon reduction targets (e.g., 90 percent or 100 percent reductions by 2050) may have another avenue to eliminate GHG emissions. In particular, end-uses in the thermal sector that are currently powered by the on-site combustion of fossil fuels could instead be powered by low- or zero-carbon variations of that same fuel. This comparison may be a necessary one in cases where policymakers are seeking to develop a complete list of comparative, politically feasible technologies that would lead to decarbonization, or in other cases where electrification is not being considered as a viable technology (e.g., under one of the counterfactuals). Under this construct, we would compare the cost of the marginal abatement technology derived from the electric sector (described above) with the cost of the marginal abatement technology derived from the thermal sector (described below). The more expensive of these two costs could then be said to be the marginal abatement cost across these two sectors.[216]

One such technology is RNG.[217] RNG is a term for natural gas that is derived from biomass or other renewable resources and is fully interchangeable with conventional natural gas. RNG can be produced through a variety of methods, including deriving biomethane from waste via anaerobic digestion or gasification, deriving hydrogen from electrolysis, and deriving synthetic natural gas from hydrogen and a renewable CO_2 source (like biomass).[218] RNG produced from each of these methods varies in both potential and costs. Of these methods, some are established technologies with decades of operating experience (e.g., extracting and purifying biomethane from biogas sources such as landfills and waste digesters), whereas other methods are still in their technological infancy (e.g., processes where electrolysis is used to produce RNG, sometimes called “power-to-gas” or “P2G”). The Synapse Team reviewed the literature to determine what an appropriate cost of RNG should be for New England.

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[216] GHG emissions are of course produced from other sectors (e.g., industrial, transportation, agriculture). Because program administrators are primarily concerned with installed measures that impact the electric and thermal sectors only, we ignore costs derived from technologies in the other sectors.

[217] Other technologies, such as diesel with high biofuel contents (e.g., B100) were also considered for analysis. However, they were ultimately not included due to (a) their low availability and (b) the challenges and costs associated with converting existing furnaces and boilers to utilize this fuel. In other words, RNG can be used alongside or in place of conventional natural gas in existing heating technology; the same cannot be said for B100 and home heating oil.

[218] “The Challenge of Retail Gas in California’s Low-Carbon Future.” California Energy Commission. April 2020. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf.

The primary source we evaluated is a March 2020 report published by ICF on behalf of Washington Gas Light Company.[219] ICF provides an estimate of nationwide RNG production for four years (2025, 2030, 2035, and 2040) across three scenarios (conservative low, achievable, and aggressive high) for nine different types of RNG. The maximum potential in 2035 (the scope of AESC 2021) is 6 quadrillion Btu per year for the nation as a whole. This is compared to natural gas consumption in New England in the residential and commercial sectors of 9 quadrillion Btu in 2019.[220] This suggests that even if the entire country's potential for RNG were dedicated to New England, the marginal cost of RNG would be the most expensive technology available, if it were being deployed at a scale to considerably abate GHG emissions.

The ICF study identifies P2G as being the most expensive variation of RNG. This technology involves having renewable technology produce hydrogen, which is then combined with CO_2 to create methane. P2G is also the RNG variation that is least limited by available feedstocks, and thus able to meet marginal needs comparable in scale to the regional demand for natural gas.

ICF states that P2G has a production cost of about $25 per MMBtu, assuming large economies of scale. Assuming RNG derived from P2G completely replaces the consumption of natural gas (which has an emissions rate of 53 kg CO_2 per MMBtu), this translates into a cost of $471 per metric ton.[221] This value does not include the cost of CO_2 for the methanation reaction, which ICF estimates at $30 per metric ton.[222] Other estimates describe the cost of CO_2 direct air capture in the 2035 timeframe at about $60

[219] Note that the 2020 report is discussed here as it is the most recent and most comprehensive contribution from ICF on this topic.

"Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington, D.C. Metropolitan Area." ICF Resources Inc. March 2020. Available as Appendix D at https://edocket.dcpsc.org/apis/api/filing/download?attachId=101994&guidFileName=e69b6cb2-963c-4122-aca3-3b45e838b2b7.pdf.

American Gas Foundation. December 2019. *Renewable Sources of Natural Gas*. Available at https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Executive-Summary-Final-12-18-2019-AS-1.pdf.

ICF International. Last accessed March 11,2021. "Design Principles for a Renewable Gas Standard." ICF.com Available at https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/5a56701dec212d1888aa212a/1515614239606/ICF_WhitePaper_Design_Principles.pdf.

[220] Data on natural gas consumption obtained from https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm. This quantity does not include natural gas consumed in the industrial sector, electric power sector, or for pipeline and distribution use. Altogether, natural gas consumption in New England in 2019 totaled about 32 quadrillion Btu.

[221] Some types of RNG are described as having negative emission rates as they avoid upstream GHGs associated with natural gas (e.g., from production). Because P2G simply avoids the use of conventional natural gas, these emissions can be ignored. We also ignore emission reductions associated with pipeline leakage, as these emissions are not considered elsewhere in the AESC study.

U.S. Energy information Administration. February 2, 2016. "Carbon Dioxide Emissions Coefficients." Eia.gov. Available at https://www.eia.gov/environment/emissions/co2_vol_mass.php.

[222] ICF 2020, at page 76. Units are assumed to be in metric tons. Another set of costs that are not included here are the costs of a heat sink (for the waste heat produced from methanation). Because these costs could theoretically be a benefit (i.e., the heat could be repurposed), we ascribe no cost or benefit to this component.

per metric ton.[223] Adding either of these two CO_2 costs to $471 per metric ton and performing unit conversions yields a range of $455 to 482 per short ton (in 2018 dollars). Averaging these two values and converting to 2021 dollars produces a value of $493 per short ton. Depending on the policy envisioned, it is possible that this cost could be imposed at its full value and carried through to the end of the study period, or implemented along some phase-in trajectory (e.g., evoking an RPS-like policy for natural gas). For purposes of simplification, and to match assumptions made for other marginal abatement costs, we assume that the same RNG cost is used in all analyzed years. Because this is greater than the abatement cost derived from the electric sector, this is our local perspective estimate for an abatement cost derived from multiple sectors.

Caveats to damage costs and marginal abatement costs

Both damage costs and marginal abatement costs have uncertainties. Damage costs are typically based on sophisticated climate and economic modeling, and may depend on the inputs being used or the algorithms applied. Damage costs are also sensitive to assumptions on discount rates, geographic scope, and considerations of high-risk situations. Likewise, of abatement cost modeling requires numerous assumptions on available technologies, costs, potentials, emissions reduction targets, and timescales.

8.2. Non-embedded NO_X costs

Combustion of natural gas creates NO_X emissions. NO_X contributes to ground-level ozone and smog, and a cause of respiratory illness. These emissions are reduced but not eliminated by current regulations.

As in previous AESC studies, we have conducted a review of the literature to develop an estimate of the damage cost of NO_X emissions (e.g., the cost that NO_X emissions impose on human health). As in AESC 2018, we rely on one 2015 study's published averages for the continental United States in the early 2010s.[224] Converted to 2021 dollars per short ton of nitrogen (N) (and rounded to the nearest $100), it found a low case of $7,200, a median of $32,600, and a high case of $68,800.[225] Based on molecular weights, a price per ton of N implies a lower price per ton of NO_X: 47 percent of the N price for NO, and

[223] Sutherland, B. G. (2019). Pricing CO_2 Direct Air Capture. *Joule*, Cell Press. Volume 3, Issue 7, 17 July 2019, Pages 1571-1573. https://doi.org/10.1016/j.joule.2019.06.025.

[224] U.S. Environmental Protection Agency. "Public Health benefits per kWh of Energy Efficiency and Renewable Energy in the United States: a Technical Report." Epa.gov. Available at https://www.epa.gov/sites/production/files/2019-07/documents/bpk-report-final-508.pdf

Other sources examined include Gilmore, E. A., Heo, J., Muller, N. Z., Tessum, C. W., Hill, J. D., Marshall, J. D., & Adams, P. J. (2019). An inter-comparison of the social costs of air quality from reduced-complexity models. *Environmental Research Letters*, 14(7), 074016. https://doi.org/10.1088/1748-9326/ab1ab5. These sources were not ultimately included in this review as they cover a more limited scope of NO_X impacts, or are more concerned with variations in modeling approaches of air quality, as opposed to the resultant NO_X costs themselves.

[225] 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. https://doi.org/10.1088/1748-9326/10/2/025006. Calculated from Table 1, assuming $1.00 in 2008 = $1.17 in 2018. Values are calculated by summing the aggregate effects from "atmospheric NO_X" from each column (low, median, and high).

30 percent for NO_2.[226] Assuming a 90/10 mix of NO and NO_2, this median value translates into a price of \$14,700 per short ton of NO_X.[227]

Using the dollar-per-short ton cost described in the first study, and assuming the summer on-peak marginal NO_X emissions rate in Table 80, we find an avoided cost for NO_X equal to \$0.77 per MWh.

8.3. Applying non-embedded costs

Non-embedded costs can be applied to both the electric sector and non-electric sectors. The following sections describe the approaches for each.

Electric sector

AESC 2021 embeds three electric-sector regulations in New England in its forecast of avoided energy costs: one (RGGI) is modeled regionwide, while two (310 CMR 7.74, a mass-based, declining cap on in-state CO_2 emissions, and 310 CMR 7.75, the Clean Energy Standard) apply only to Massachusetts and are used to represent a reasonable and current estimate for the cost of compliance for the Massachusetts GWSA regulations. In AESC 2021, we sum these embedded costs (all three for Massachusetts, RGGI only for the other five states), then subtract the annual values from the relevant marginal abatement cost (see Table 79).

Table 79. Interaction of non-embedded and embedded CO_2 costs.

Component description	Formula
Marginal abatement cost (including non-embedded components)	a
Non-MA allowance price (embedded components, including RGGI)	b
MA allowance price (embedded components RGGI, 310 CMR 7.74, 310 CMR 7.75)	c
Externality cost (non-MA)	d = a - b
Externality cost (MA)	e = a - c

The resulting cost stream (measured in dollars per short ton) can then be multiplied by a marginal emissions rate (measured in short tons per MWh) to be converted into dollars per MWh. In this context, a "marginal" emission rate refers to the emission rate associated with the resources that change their output (e.g., ramp up or ramp down) as more demand is added or removed from the grid.[228] There are short-run and long-run emission rates, each of which has separate implications for the resulting dollar-

[226] A one-ton 50/50 mixture of NO and NO_2 contains 770 lb of N based on molar fractions of N in both NO and NO_2. The value of the nitrogen in the one-ton mixture of the AESC NO_x will be 38.6 percent of the dollar price per ton.

[227] Fluid. Last accessed March 11, 2021. *Nitrogen oxides Formation in Combustion Processes*. Available at http://fluid.wme.pwr.wroc.pl/~spalanie/dydaktyka/combustion_en/NOx/NOx_formation.pdf. Pg. 42

[228] This can be contrasted with an "average" emissions rate, which refers to the total emissions produced by the grid over a long period of time (often a year) divided by the total generation output by the grid. This emissions rate includes many resources (e.g., nuclear, hydro) that do not economically respond to changes in demand.

per-MWh values. Short-run and long-run marginal costs may both be applied to measures that decrease electricity consumption (e.g., energy efficiency) the same way they are applied to measures that increase electricity consumption (e.g., heat pumps).

Short-run marginal emission rates

Using EnCompass, we calculate the marginal CO_2 and NO_X emission rates by comparing results in Counterfactual #1 with results in Counterfactual #2. Specifically, we calculate the change in emissions in each year, and divide that number by the change in demand. The result is the marginal emissions rate for any given year.[229] This emissions rate can then be aggregated over multiple hours to provide a set of summarized marginal emissions rates (see Table 80). Marginal CO_2 emission rates in the early periods are similar those found in other sources.[230] Marginal NO_X emission rates in the early periods tend to be lower than other sources for a number of reasons: chief among them, NO_X emission rates continue to fall as the grid relies more often on cleaner power plants and as the dirtiest power plants retire.

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229 This is the same theory used to produce marginal emissions and emission rates in U.S. Environmental Protection Agency's AVoided Emissions and geneRation Tool (AVERT).
U.S. Environmental Protection Agency. Last accessed March 11.2021. "Avoided Emissions and Generation Tool (AVERT)." *Epa.gov.* Available at https://www.epa.gov/statelocalenergy/avoided-emissions-and-generation-tool-avert.

230 For example, see Table 150 in AESC 2018 (available at https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf), Table 5-5 in ISO New England's 2018 Air Emissions Report (available at https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf), and data from U.S. EPA's AVERT model for uniform energy efficiency measures installed in New England (available at https://www.epa.gov/sites/production/files/2020-09/avert_emission_factors_09-08-20.xlsx).

Table 80. Modeled electric sector marginal emissions rates (lb per MWh)

	CO_2				NO_X			
	Winter		Summer		Winter		Summer	
	On Peak	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*
2021	756	791	779	799	0.09	0.21	0.14	0.11
2022	740	752	729	813	0.10	0.09	0.14	0.11
2023	732	826	663	932	0.09	0.08	0.11	0.09
2024	791	869	767	967	0.10	0.08	0.12	0.10
2025	796	881	812	966	0.07	0.07	0.12	0.10
2026	756	878	772	939	0.07	0.07	0.11	0.09
2027	682	824	760	930	0.07	0.08	0.11	0.10
2028	686	735	764	822	0.08	0.07	0.12	0.09
2029	702	718	753	794	0.08	0.07	0.11	0.08
2030	636	669	732	760	0.06	0.06	0.09	0.07
2031	648	692	723	768	0.06	0.06	0.09	0.07
2032	644	720	686	774	0.06	0.06	0.09	0.07
2033	652	702	737	788	0.06	0.06	0.08	0.07
2034	678	693	752	770	0.06	0.06	0.08	0.07
2035	691	690	761	793	0.06	0.05	0.07	0.06

Notes: We assume all four counterfactuals feature the same marginal emission rates.

This same step can be applied for both non-embedded GHG costs and non-embedded NO_X costs. Because there are no embedded NO_X prices included in AESC 2021's production cost modeling (e.g., in the same way that RGGI embeds some of the cost of CO_2 emissions), there is no preliminary Table 79-equivalent subtraction step required.[231]

These emission rates are "short-run" because they assume a single year that has no other changes to the grid other than the assumed "dummy" resource. In other words, they account for the hourly system demand for wholesale generation decreasing in response to this "dummy" resource, but do not incorporate any second-order effects. These short-run marginal emission rates are best used for analyzing emission changes over a period of less than one year.

Long-run marginal emission rates

Conversely, a long-run marginal emission rate takes these second-order effects into account. For the purposes of AESC 2021, the primary second-order effect to consider are renewable builds. These marginal emission rates are best used for analyzing emission changes over a period greater than one year. The following paragraphs provide guidance on one methodology that AESC users can apply to adjust their marginal emission rates.[232]

[231] Costs of controls or technology that limit or reduce NO_X emissions from individual power plants are not considered.

[232] Because the avoided energy, avoided capacity, and other avoided costs do not change based on the selected emissions accounting approaches, these avoided costs are independent of the AESC user choice of a long-run marginal emission rate approach.

All New England states have some kind of RPS policy in effect (see Chapter 7: *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* for more information). Under these policies, LSEs (such as electricity utilities) must procure a quantity of RECs equal to a specified percentage of that entity's electricity sales in a particular year. In many jurisdictions, this percentage increases over time for "Class 1" markets. However, consider a hypothetical in which the percentage is flat: if electricity sales go up, then the entity will have to purchase and retire more RECs (implying the addition of more renewables to the grid). If electricity sales go down (e.g., as a result of increased energy efficiency programs) the entity will have to purchase and retire fewer RECs.[233] Because the renewables driven by these RPS policies would also displace marginal generators and decrease emissions, ignoring the effects of these policies will overestimate the emissions-reducing impacts of energy efficiency and other DSM resources.

For time periods of one year or more, the marginal emissions rate is derived from not only the marginal displaced resource, but also RPS percentage targets (which require demonstration of compliance annually). One can determine the effect of these RPS policies on the overall marginal emissions rate by calculating a weighted average of the model-derived emissions rate and the share of resources purchased to meet RPS targets. For example, consider a hypothetical state with a 50 percent Class 1 RPS target and a supporting policy to meet this obligation through long-term contracts with zero-carbon resources. In this situation, if 1 MWh of energy efficiency were deployed, load would decrease by 1 MWh, avoiding the purchase (and possibly creation) of 0.5 MWh of zero-carbon generation.[234] As a result, this 1 MWh would avoid 0.5 MWh associated with the marginal emissions rate described in Table 80, and 0.5 MWh of zero-emitting energy. We assume this methodology is applicable only to RPS categories where compliance is achieved through the retirement of RECs associated with non-emitting resources.[235]

However, renewable policies only impact the marginal emissions rate in certain circumstances:

- First, some states may have policies that require utilities to purchase renewables or other types of zero-emitting generation on an absolute MWh basis. In these circumstances, contracts for renewable energy are not linked to load, meaning that variations in load (due to energy efficiency or other DSM programs) do not have any effect on marginal emission rates. If a state only had policies of this type (i.e., with no RPS-style policies), the long-run marginal emission rates would be equivalent to the short-run marginal emission rates.

[233] Importantly, the renewable energy attributes of these MWh must be claimed in some way (i.e., the retirement of RECs) in order to ensure there is no double-counting among different entities in New England.

[234] This simplified example does not consider impacts of T&D losses.

[235] For example, there are some RPS categories where compliance is primarily achieved through the retirement of RECs associated with combined-heat-and-power plants. These plants have similar emissions rates to the systemwide marginal emission rate, and therefore do not contribute to avoided emissions.

- Second, because of the overlap among resources that qualify for both these contracting policies and RPS policies, sometimes the amount of available renewable energy exceeds the quantity required under an RPS. For example, consider a hypothetical where utilities in a state with 20 TWh are (a) required to purchase 12 TWh of renewable resources in any given year, and (b) the state also has an RPS wherein utilities must purchase and retire RECs equivalent to 50 percent of their electricity sales (10 TWh). In this hypothetical, the state's RPS policy is exceeded by 2 TWh, meaning that changes to load (short of increasing load by 2 TWh) will not have an impact on the quantity of renewables purchased by that state.

For any one state, the marginal renewable (RE) fraction that should be applied to the modeled marginal emissions rate can be calculated using the algorithm in Equation 2. The marginal RE fraction is then applied to the modeled marginal emissions rate in Equation 3 to determine the final marginal emissions rate.

Equation 2. Marginal renewable (RE) fraction

$$[A]\ Total\ RPS\ requirement\ (\%) = RPS\ Class\ 1\ \% + RPS\ Class\ 2\ \% + \cdots + RPS\ Class\ N\ \%$$

$$[B]\ Required\ RE\ as\ a\ fraction\ of\ sales\ (\%) = \frac{Contracted\ RE + Zero\ Carbon\ (RECs\ not\ resold) + Additional\ RECs\ retired\ (MWh)}{State\ electricity\ sales}$$

If [B] > [A]

Then marginal RE fraction (%) = 0%

Else marginal RE fraction (%) = [A]

Equation 3. Final marginal emissions rate

$$Final\ marginal\ emissions\ rate = Modeled\ marginal\ emissions\ rate \times (1 - marginal\ RE\ fraction)$$

In our example, [A] is equal to 50 percent. Because the total number of RECs retired is 12 TWh (all 12 TWh of RECs from the contracting policy as assumed retained, with no further RECs needed to meet the RPS policy), [B] is equal to 12 TWh divided by 20 TWh, or 60 percent. Because B is greater than A, the marginal RE fraction is zero. This makes the final marginal emissions rate equal to the modeled marginal emissions rate.

In some circumstances, if [A] and [B] are very close together, applying some quantity of demand-side measures may cause [A] to exceed [B] or vice versa. In these situations, the marginal RE fraction should be calculated separately first for (i) the quantity of demand-side measures that are under the threshold where [A] is less than [B] (or vice versa) and second for (ii) the quantity of demand-side measures that are over the threshold. Calculating the marginal emissions rate in this situation is challenging, but doable. Practically speaking, this circumstance is unlikely to occur for two interrelated reasons:

- First, based on our renewable energy market fundamentals analysis, we anticipate an RPS compliance surplus in each state, in each counterfactual, and in each study year.

REC supply and demand are expected to be closest to equilibrium during the first three years of the study period. During this time, while current-year REC supply *may* trail current-year demand in one or more years, RPS-obligated entities currently hold large 'bank balances' (which refers to excess RPS compliance that LSEs collectively already have at their disposal) which can be used to fulfill RPS obligations and therefore provide a clear signal that no incremental renewable energy builds are required. In the middle and later years of the study period, regional REC surpluses of up to 5,600 GWh *per year* are expected.

- Second, the quantity of demand-side measures would likely have to be very large to cause the positions of [A] and [B] to switch. At any given time, program administrators are likely only screening one to three years' worth of measures or programs, a quantity that is unlikely to absorb the modeled REC surpluses by itself.

In other words, because regional REC surpluses are expected throughout the study period—obviating the need for renewable energy builds beyond policy-mandated supply—in all counterfactuals, any quantity of demand-side measure deployed (whether it increases or decreases demand) is unlikely to affect the quantity of renewables built.

Some AESC users may take a state- or utility-specific approach to calculating changes in emissions that result from changes in an area's load, using an area-specific emission inventory, rather than the regionwide approach described above. For example, a state may account for emissions based only on the amount and type of RECs retired by utilities serving load in the relevant sub-regional area. For these users, procurements of fixed quantities of renewable or zero-carbon resources outside of the relevant jurisdiction may not affect the jurisdiction's emissions, and RPS policies could be considered to be binding if the area-level value of [A] exceeds [B]. In this approach and circumstance, the final marginal emission rate would be equal to (i) the modeled emissions rate multiplied by (ii) the number of RECs divided by the statewide electricity load.[236]

Non-electric sectors

The approach for the non-electric sectors is simpler. The dollar-per-ton non-embedded value is simply multiplied by the relevant non-electric emissions rate (measured in tons per MMBtu) to produce dollar-per-MMBtu values. These emission rates may be fuel- and sector-specific (see Table 17 and Table 18 for more information on non-electric emission rates). Because policies like RGGI and RPS only impact the electric sector, they should not be taken into account when calculating non-electric sector impacts (i.e., they are not embedded).

[236] This term (ii) is functionally equal to the state or sub-region's annual RPS percentage, assuming that all RECs procured to meet the annual RPS percentage are retired.

9. 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. In some contexts, DRIPE maybe called "price suppression" or "price effect."

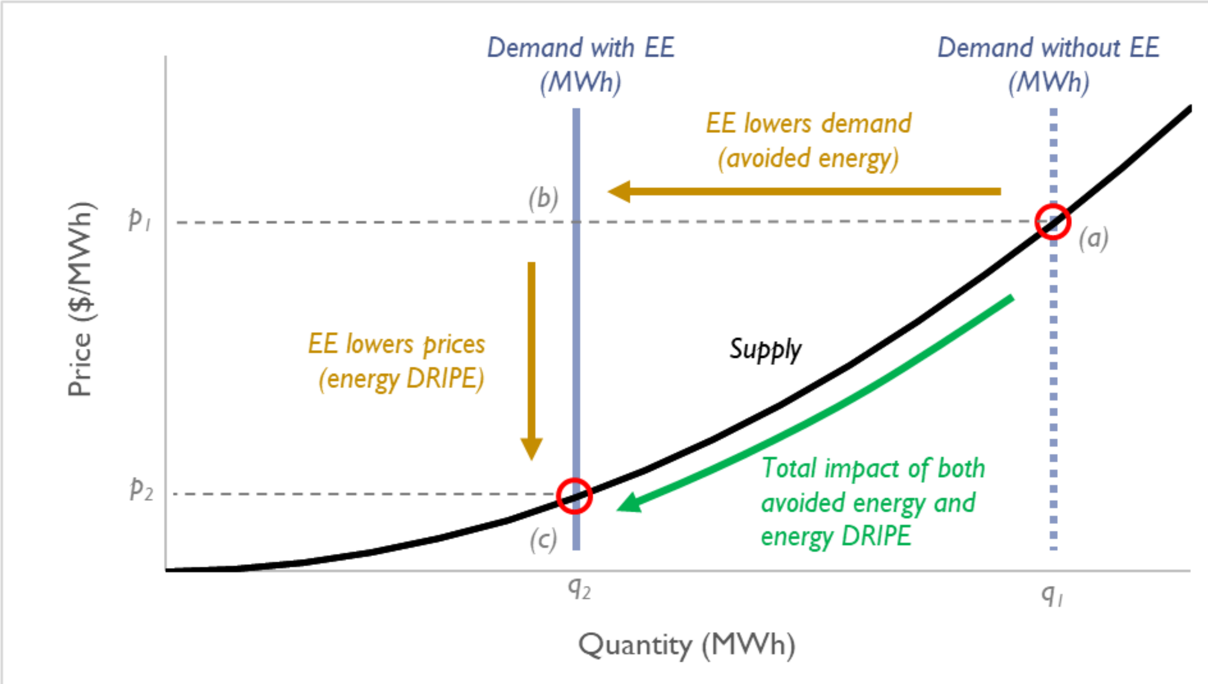
This chapter describes our results, methodology, and assumptions for energy DRIPE, capacity DRIPE, natural gas DRIPE, fuel-oil DRIPE and cross-DRIPE effects using a combination of quantitative analyses of national and New England data rather than modeling projected market conditions.

DRIPE results in AESC 2021 differ from those in AESC 2018 as a result of updated information about supply in each of the markets examined. Generally speaking, we find (a) lower energy DRIPE and capacity DRIPE values due to projections of flatter supply curves compared to AESC 2018, (b) lower natural gas DRIPE values due to lower commodity prices and flatter supply curves, and (c) lower oil DRIPE values due to changes in the underlying projection of crude oil prices. See each of the subsections below for detailed comparisons of DRIPE values in AESC 2018 and AESC 2021.

9.1. Introduction

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. It is a separate and distinct benefit from avoided energy, avoided, capacity, avoided natural gas, and avoided oil. Figure 46 illustrates the impact of DRIPE. Whereas avoided energy (for example) describes the benefits associated with a quantity reduction, avoided energy DRIPE describes the benefits associated with a price reduction. These effects are not double-counting—in this Figure 46, each energy DRIPE and avoided energy (yellow arrows) are separate vector components of the aggregate effect (green arrow). The total cost at point (a) is equal to $p_1 \times q_1$, while the total cost at point (c) is equal to $p_2 \times q_2$. If DRIPE were uncounted, the total cost would incompletely be calculated as the cost at point (b), or $p_1 \times q_2$.

Figure 46. Example figure depicting separate and non-overlapping avoided energy and energy DRIPE effects



Note: This example figure depicts impacts in the energy market, but the principles are the same for all other DRIPE categories. This figure also uses "EE" as an example measure. DRIPE effects can be calculated for any measure (EE or otherwise), including measures that increase the demand of a commodity.

Broadly speaking, we model five categories of DRIPE in AESC.

- **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 cross-DRIPE discussed below.

- **Capacity DRIPE:** The change in state and regional electricity bills due to reductions in electric capacity prices.

- **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).

- **Cross-DRIPE:** The value that gas reductions have on electricity prices and that electricity reductions have on natural 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**: The benefits to electricity consumers that result from lower gas demand reducing gas prices for electric generation.

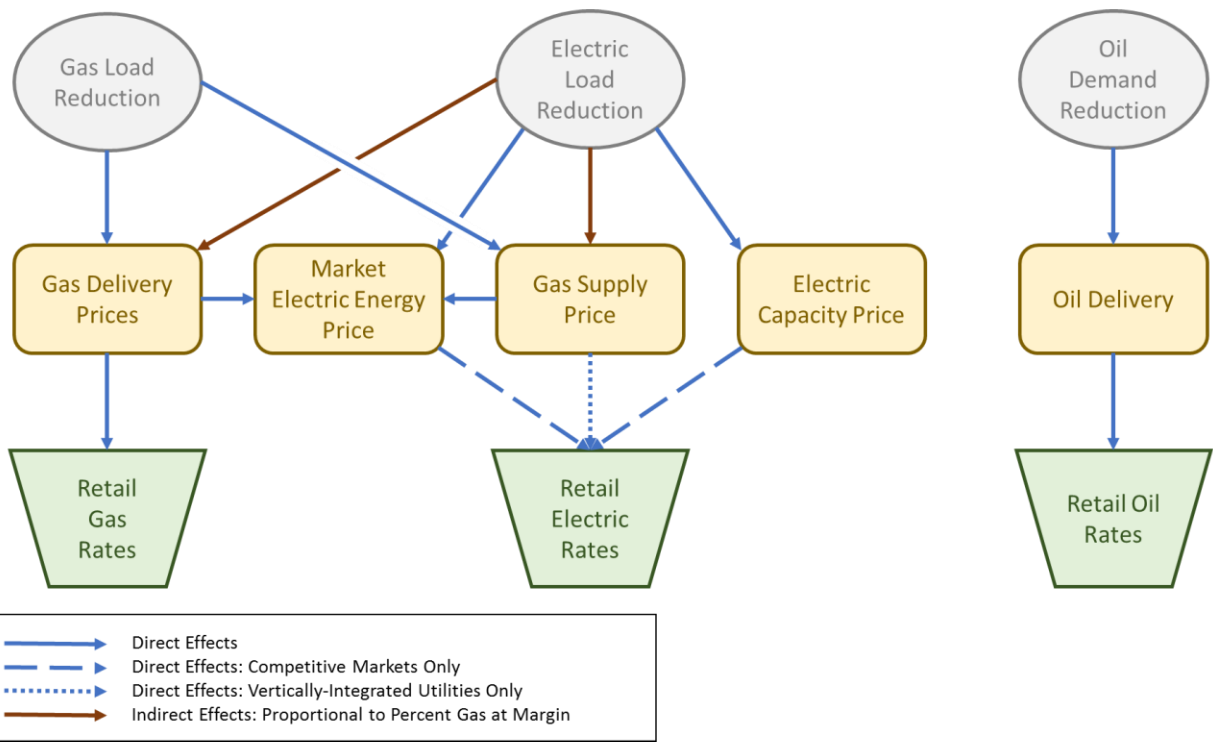
    - **Electric-to-Gas (E-G) cross-DRIPE**: The benefits to gas consumers from a reduction in electricity demand and hence gas demand for generation.

- **Electric-to-Gas-to-Electric (E-G-E) cross-DRIPE**: 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.

- **Own-price oil DRIPE:** The value of reduced demand for petroleum products (e.g., gasoline, diesel, residual) on petroleum prices.

The interactions of DRIPE effects are shown in Figure 47.

Figure 47. DRIPE effect interactions



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 are unlikely to exist in perpetuity, however, so benefits are adjusted downward, or decayed, to reflect how other market participants respond to changes in market price over time.

Our estimates indicate that the DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms for the state or region. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts.

General DRIPE methodology

In AESC, DRIPE is estimated according to the following steps:

1. First, a "price shift" is calculated. This shift represents the change in price (e.g., dollars per MWh) for a change in demand (e.g., MWh). Aggregated over many data points, this price shift represents the supply curve of a particular resource. For many DRIPE categories, this is calculated using a regression, where we observe many hundreds or thousands of historical datapoints to establish a relationship between prices and demand. For other DRIPE categories, these price shifts are based on an assumed supply curve. This most notably occurs for capacity DRIPE, where there is not enough information to develop a regression from historical data.

2. Second, these price shifts are multiplied by total future market demand, so that they may then be applied to any generic change in demand. In other words, the price shift is expressed in terms of price-per-demand.[2] Multiplying the price shift by demand translates it into a price-per-demand value that can then be multiplied by a measure's anticipated savings.[237]

3. Finally, the price-per-demand value is adjusted. This may include accounting for hedged demand which has, in theory, already been purchased and is not subject to price shifts. Or, it may involve reducing benefits to account for decays in effects, or "phasing in" of effects to describe a lag in the way the market realizes these impact. Importantly, only some categories of DRIPE have these shifts applied.

Depending on the DRIPE category, these steps may be more complex or performed in a different order (in order to facilitate computation).

Price effects impact the entire region because there is only one market each for electric energy, electric capacity, and natural gas. For all the DRIPE categories described in AESC, we estimate both intra-zonal DRIPE (i.e., the benefits that accrue within a zone from load impacts within that zone, sometimes called own-zone or zone-on-zone) and inter-zonally (i.e., the benefits that accrue beyond that zone's borders in the "rest of pool"). Intra-zonal DRIPE is calculated by multiplying the price effect for a particular category of DRIPE by a single state's projected demand (rather than the regional total). Meanwhile, inter-zonal DRIPE is calculated by subtracting the intra-zonal value from the regional total.[238]

In some jurisdictions, only "intra-zonal" DRIPE benefits are used in cost-effectiveness testing. The reason may vary, but in some cases, there may be a regulatory directive to only count the benefits that accrue to a particular state's ratepayers. However, we note that the inter-zonal benefits continue to exist even if

[237] Throughout this chapter, we frequently discuss DRIPE in terms of benefits relating from savings, but DRIPE is a non-directional value that can also describe price increases resulting from increased demand. Some measures that reduce the use of one kind of fuel (e.g., natural gas) but increase use of another fuel (e.g., electricity) may end up utilizing nearly all the DRIPE categories described in this chapter.

[238] An equivalent mathematical operation would be to multiply the price shift by the regional total demand less the demand for the state in question.

they are not counted in a measure's cost-effectiveness test. We also note that these benefits are not counted by any other state.

The remaining text of this chapter describes the specific methodology used to generate DRIPE benefits for each category of DRIPE.

9.2. Electric energy DRIPE

A reduction in electricity demand should reduce wholesale energy prices, which benefits all market participants. This section describes the AESC 2021 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.

Our estimates of electric energy DRIPE follow the same approach used in previous AESC studies from 2009 to 2018. Generally speaking, we conduct a set of regressions of historical zonal hourly market prices against zonal and regional load to develop elasticities. Then, we estimated the timing and duration of benefits based upon the following market realities:

1. The reductions in wholesale prices are assumed to flow through to customers as existing contracts and other resources (legacy resources, renewable contracts, basic-service and other default contracts, direct contracts with marketers) expire.
2. Customers will respond to lower energy prices by using somewhat more energy.[239]
3. The generation market will respond to sustained lower prices by some combination of retiring and de-rating existing generating capacity and delaying new resources that reduce market energy prices (such as gas combined-cycle units and high-efficiency combustion turbines).
4. Lower loads will tend to result in lower acquisition mandates under renewable and other alternative-energy standards that are stated as a percentage of energy sold.

Regression model selection

AESC 2021, like AESC 2018, 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

[239] Other factors (e.g., purchases of renewables, transmission construction, grid modernization, recovery of energy-efficiency costs) may simultaneously raise prices. The energy DRIPE considers only the marginal effect on market energy prices on retail prices and hence usage.

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. 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.

In prior AESC studies, 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 4, relates zonal price to ISO-wide demand and to natural gas prices.

Equation 4. Regression equation relating zonal electric energy prices to ISO demand and natural gas prices

$$LMP_{Zone} = \beta_0 + \beta_1 Demand_{ISO} + \beta_2 {Demand_{ISO}}^2 + \beta_3 {Demand_{ISO}}^3 + \beta_4 Price_{NG}$$

Equation 4 describes a cubic function. 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 (e.g., when the market’s marginal unit might switch from a gas peaker to a natural gas-fired combined cycle unit), prices will increase by approximately 30 percent even though demand might only increase a few MW. In the middle of the offer stack, by contrast, switching from a more efficient gas combined cycle to a slightly less efficient one will only increase prices by a few percent. In Equation 4, changes in natural gas prices shift the overall curve up or down but do 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**, which is a 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. **Simple formulation**, where only key attributes are included

Note that the “ISO Demand” described Equation 4 is <u>not</u> the total ISO-wide demand for electricity. Instead, this variable is perhaps better described as “net demand,” which is calculated by subtracting hourly wind, solar, and nuclear output from gross demand reported by ISO New England. Wind and solar vary throughout the day predictably (especially for solar) and less predictably (as a function of weather).

Nuclear output is quite even most days, but is sometimes reduced or eliminated due to planned and unplanned outages. None of these generators are subject to load- or price-based dispatch, since they self-schedule or bid into ISO New England's energy market at very low (in the case of wind, even negative) prices.[240] As a result, we remove the MWh contribution of these non-price-responsive generators from our "ISO Demand" variable.

In AESC 2021, we utilize data from January 2018 through December 2019 as the basis for our regressions.[241] Figure 48 plots actual price and demand data (in blue) against predicted data (in red) estimated using Equation 4 for one illustrative region and period. A similar regression was performed for nine regions (ISO-wide, Connecticut, Maine, New Hampshire, Rhode Island, Vermont, SEMA, NEMA, and WCMA), and for 24 time periods (one off-peak period and one on-peak period for each month).[242]

240 In earlier AESC studies, we also examined the impact of removing the hourly contribution of other resource types from the regression. Availability of other generation may also affect market energy prices, but the relationship between price and output is complicated. The dispatch of thermal plants is driven by loads and energy prices; commitment of steam and combined-cycle plants is driven by forecast loads and prices; and hydro is scheduled within the week and the day to minimize costs of energy and reserves. It is therefore difficult to determine whether a plant is not running (1) because it is not available, (2) because energy price is below the plant's energy bid, or (3) because it is being held back as reserve (especially in the case of hydro and fast-start combustion turbines) or to meet higher loads expected later in the hydro operating cycle. The output of most fossil units can be determined from EPA's Air Market Programs dataset, and ISO New England provides total daily capacity that is unavailable due to outages or failure to commit in the day-ahead market, but these sources do not provide enough detail to determine why particular units are not operating. In any event, the regression results are very similar whether gross load or net load is used in Equation 4, reducing the usefulness of any additional complexity.

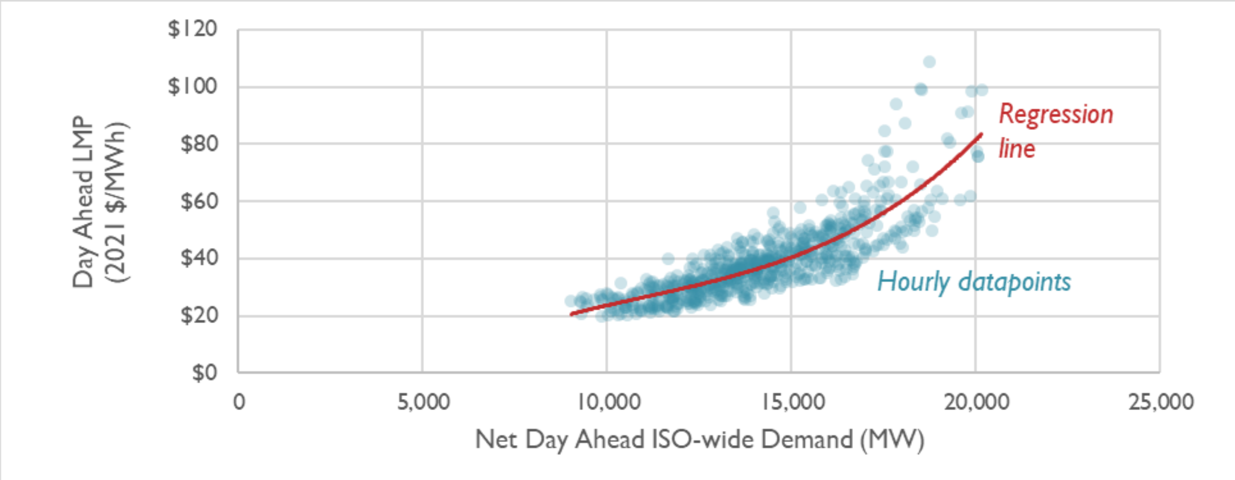
241 This time period spans 17,520 datapoints, which provides our regressions with sufficient detail to accurately predict the relationship between prices and loads. Hourly energy price data and gross load data was obtained from ISO New England (ISO New England. 2019. *ISO new England Public*. Available at https://www.iso-ne.com/static-assets/documents/2019/02/2019_smd_hourly.xlsx) and (ISO New England. 2018. *ISO New England Public.* Available at https://www.iso-ne.com/static-assets/documents/2018/02/2018_smd_hourly.xlsx)

Sub hourly data on ISO New England's fuel mix was downloaded from ISO NE (ISO New England. Last accessed March 11, 2021. "Dispatch Fuel Mix*." Iso-ne.com*. Available at https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/gen-fuel-mix) then averaged to produce hourly results for wind, solar, and nuclear generation. Daily data on delivered prices to Algonquin Citygate were obtained from (NGI. 2021. "Algonquin Citygate Daily Natural gas Price Snapchat." Available at https://www.naturalgasintel.com/data-snapshot/daily-gpi/NEAALGCG/)

For points with very low zonal LMP, elasticities are very large. This is a byproduct 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. These exclusions occur very rarely—for the ISO New England region, for example, there is one such hour.

242 A similar approach is used to calculate regressions for "top" hours, for use in DSM measures that do not operate the entire year but are instead targeted at certain hours. Rather than 24 periods, we calculate regressions for 374 periods for all 9 regions. This includes 68 summer off-peak regressions, 58 summer on-peak regressions, 132 winter off-peak regressions, and 116 winter on-peak regressions. Each of these batches of regressions is divided in half into regressions that span "Top Load" and "Top LMP" hours. Within Summer, On-Peak, Top Load (for example), there exists regressions that cover the top 50 hours (sorted by ISO-wide demand), the top 100 hours, the top 150 hours, and so on. Asymmetry in number of regressions across different time slices (summer, winter, on-peak, and off-peak) is due to differences in the number of hours included within each time slice.

Figure 48. Illustrative regression for WCMA, July on-peak hours



Note: This chart is shown for illustrative purposes only. To plot the red, fitted line in the figure, we assume a daily price of $0 per MMBtu for natural gas (as multivariate regression cannot be displayed in a two-dimensional chart). This differs from our actual analysis where different natural gas prices were used for each point. Final DRIPE calculations use monthly timeframes instead of quarterly; different zones have different price/load pairs.

In general, the model produces a good fit (R^2 above 0.7) for 87 percent of the 216 regressions (24 periods X 9 regions). The remaining regressions feature R^2 values that range from 0.5 to 0.7. These poorer fits are typically found during off-peak or spring and fall time periods. The average R^2 value for the gross-demand model, across all zones, months, and periods is 0.8, and the minimum R^2 across all zones/periods/months is 0.5.

Calculating elasticities from the regression

After establishing a functional form to model the relationship between price and demand, we then estimate elasticities using these regressions. For each regression, we first calculate the derivative of the polynomial regression model (Equation 4) with respect to demand:

Equation 5. Calculation of regression derivative

$$Instantaneous\ slope = \frac{\partial LMP_{Zone}}{\partial Demand_{ISO}} = \beta_1 + 2\beta_2 Demand_{ISO} + 3\beta_3 {Demand_{ISO}}^2$$

For each hour within a regression, this derivative describes how price would change in each hour for a small change in demand. Next, we apply Equation 6 to describe the elasticity for each hourly data point (e.g., an estimate of the percent change in price per percent change in demand).

Equation 6. Calculation of elasticity

$$Elasticity = \frac{\%\ change\ in\ price}{\%\ change\ in\ demand} = \frac{Instantaneous\ slope\ of\ price\ relative\ to\ demand}{Hourly\ electricity\ price} \times Hourly\ demand$$

Each of the resulting elasticities are then aggregated into a single load-weighted elasticity for each regression. This average elasticity represents the average price response to a small change in demand for a given zone, season, and period. Electric energy DRIPE elasticities are presented in Table 81 by zone, month, and period.[243]

Table 81. Energy DRIPE elasticities

Period	Month	ISO NE	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA
Annual		1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
Off-peak	**1**	2.3	2.4	2.3	2.3	2.2	2.2	2.2	2.2	2.3
	2	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	3	1.1	1.2	1.1	1.1	1.1	1.0	1.1	1.1	1.1
	4	1.0	1.0	1.0	1.0	0.9	1.1	1.4	0.9	0.9
	5	0.7	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7
	6	0.7	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7
	7	1.0	1.0	1.0	1.0	1.0	1.0	1.1	1.1	1.0
	8	1.2	1.2	1.2	1.2	1.2	1.1	1.2	1.2	1.2
	9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	10	1.1	1.2	1.2	1.1	1.1	1.1	1.1	1.1	1.1
	11	1.4	1.5	1.4	1.4	1.3	1.3	1.4	1.4	1.4
	12	1.4	1.5	1.4	1.4	1.4	1.4	1.4	1.4	1.4
On-peak	**1**	2.7	2.7	2.6	2.7	2.7	2.7	2.7	2.7	2.7
	2	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	3	1.1	1.2	1.1	1.2	1.1	1.1	1.2	1.1	1.1
	4	0.9	1.1	1.0	1.0	0.9	0.9	0.9	0.9	0.9
	5	0.9	1.0	0.9	0.9	0.9	0.9	1.0	0.9	0.9
	6	0.7	0.6	0.7	0.7	0.8	0.7	0.7	0.7	0.7
	7	1.7	1.6	1.6	1.6	1.7	1.7	1.7	1.6	1.7
	8	2.1	2.0	2.1	2.1	2.1	2.2	2.2	2.1	2.1
	9	1.1	1.1	1.1	1.1	1.1	1.2	1.4	1.1	1.1
	10	1.5	1.6	1.6	1.6	1.5	1.6	1.7	1.5	1.5
	11	1.8	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8
	12	1.5	1.5	1.4	1.4	1.5	1.5	1.5	1.4	1.5

Note: Elasticities for Connecticut subregions (Southwest CT and Other CT) are assumed to be equal to the Connecticut-wide elasticity. A Massachusetts-wide elasticity is calculated based on a weighted average of the demand for the three subregions. These values are available in the AESC 2021 User Interface.

The results are 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. On an annual basis, a 1.0 percent reduction in demand yields a 1.4 percent reduction in price. Depending on the month, a 1.0 percent

[243] We also calculate elasticities for "top" hours (described in footnote 242) using an analogous methodology to the one described here. These elasticities are not shown in this report due the large size of the table, but may be found in the *AESC 2021 User Interface*.

reduction in load throughout New England results in a 0.7 to 2.3 percent reduction in off-peak price, and a 0.7 to 2.7 percent reduction in peak price.

Comparison with AESC 2018

Table 82 describes the summary statistics from Table 81, and compares the results with analogous values from AESC 2018. Elasticities in AESC 2021 are generally lower due to differences in years analyzed (AESC 2018 estimates regressions based on data from September 2015 through August 2017, while AESC 2021 uses data for January 2018 through December 2019), and minor modifications to the elasticity algorithm.

Table 82. Comparison of energy DRIPE elasticities, AESC 2018 and 2021

		AESC 2018			AESC 2021		
		Min	*Median*	*Max*	*Min*	*Median*	*Max*
Annual		1.81	1.83	1.87	1.35	1.36	1.40
Winter	On-peak	1.95	2.35	2.59	0.87	1.38	2.71
	Off-peak	1.77	1.91	2.31	0.72	1.18	2.35
Summer	On-peak	0.98	1.81	1.94	0.65	1.50	2.22
	Off-peak	1.49	1.50	1.61	0.72	1.00	1.21

Calculating energy DRIPE

Next, we apply the above elasticities to hourly prices and loads to calculate the DRIPE benefit for any 1 MWh reduction in load. Conceptually, the value of DRIPE is equal to the change in price that results from a 1 MWh reduction in load, multiplied by the amount of load that benefits from that reduction in price.

We calculate the value of DRIPE both intra-zonally (i.e., the benefits that accrue within a zone from load impacts within that zone) and inter-zonally (i.e., the benefits that accrue beyond that zone's borders in the "rest of pool"). Equation 7 describes the calculation for intra-zone DRIPE, while Equation 8 describes the calculation for inter-zone DRIPE. Intrazonal and interzonal values are added to determine the total DRIPE effect.

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. Equation 8 is similar, but reflects how the demand reduction in Zone Z reduces prices in all other zones.

As in prior AESC studies, we assume that the value of DRIPE is reduced in two ways:

- First, rather than relying on the full energy demand values, we instead rely only on the unhedged portion of demand to calculate energy DRIPE. This is the portion of demand that has not already been purchased through long-term contracts.
- Second, we assume that the DRIPE effect decays over time. This is a series that aggregates expected effects related to resources responding to changes in prices, demand elasticity, and binding RPS policies.

Each of these two effects are described more in the subsequent subsection.

Intrazonal 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.[244] Conversely, interzonal estimates are approximately proportional to the difference between ISO load and zonal load. Zones with lower load will have higher zone-on-Rest-of-Pool values.

Equation 7. Value of intra-zonal electric energy DRIPE

$$DRIPE_{\substack{Zone\ Z\,|\,Zone\ Z \\ Period\ P}} = \left[\frac{\varepsilon_{\substack{Zone\ Z \\ Period\ P}} P_{\substack{Zone\ Z \\ Period\ P}}}{Q_{\substack{ISO \\ Period\ P}}} \times Q_{\substack{Zone\ Z \\ Period\ P}} \right] \times D$$

Equation 8. Value of inter-zonal electric energy DRIPE

$$DRIPE_{\substack{Rest-of-Pool\,|\,Zone\ Z \\ Period\ P}} = \frac{(1-\delta)_{Period\ P}}{Q_{\substack{ISO \\ Period\ P}}} \sum_{\substack{x \in Zones \\ x \neq Zone\ Z}} \varepsilon_{\substack{x \\ Period\ P}} P_{\substack{x \\ Period\ P}} Q_{\substack{x \\ Period\ P}}$$

Where:

ε is elasticity

P is the zonal market energy price ($/MWh)

$Q_{Zone\ Z}$ is zonal load less hedged supply (i.e., "unhedged load")

Q_{ISO} is ISO energy load

D is the aggregate decay effect

Energy DRIPE reductions

We assume that the value of energy DRIPE is reduced due to (a) some portion of energy purchased being bought outside the spot market for energy (i.e., hedged) and (b) a decay factor. The following subsections describe the assumptions underlying each of these effects.

Hedging assumptions

Substantial energy is purchased months or up to several years in advance of delivery, through utility contracting for standard service or a third-party contract. Hence, we assume energy DRIPE benefits are calculated only using the share of demand that is unhedged (i.e., the share that is purchased on the energy spot market). Our assumptions on energy hedging are based on four factors:

1. **Investor-owned utility contracts.** These contracts include pre-restructuring legacy contracts, post-restructuring reliability contracts in Connecticut, renewables purchases, and pending purchases from Hydro Québec.[245]

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[244] There are subtle differences that make comparison inexact because DRIPE also depends on zonal elasticity and hedging estimates.

[245] Data on these contracts is obtained from utility IRPs and FERC Form 1.

2. **Hedging in Vermont**. Vermont is the sole remaining New England state that is vertically integrated statewide. Based on the 2018 IRP for Green Mountain Power, we assume that all utilities in Vermont have about 60 percent of their energy hedged in all years.[246]

3. **Hedging of vertically integrated energy in the other five New England states**. The resources owned or under contract to the vertically-integrated utilities (various mixes of municipals and coops in the other five states) are estimated based data from EIA 861.[247] Because exact data on hedged energy is difficult to compile, we assume that all load related to vertically integrated utilities (outside Vermont) are 50 percent hedged in all years.

4. **Short term contracts.** In addition to long-term 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 assume 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. Depending on the measure vintage selected, this assumption is shifted by one year or more.

Table 83 depicts the aggregate unhedged share of energy by year in Counterfactual #1.

[246] The 2018 IRP of Green Mountain Power (which serves the majority of Vermont load) reports 70 percent of its energy comes from owned resources and long-term contracts. The price of the 24 percent of GMP's energy supply that came from Vermont's long-term contract with Hydro Québec varies in undisclosed part with market prices, so perhaps 60 percent of GMP's energy supply is price hedged. We assume all other utilities in Vermont use the same percentage of hedged energy.

[247] EIA Form 861, 2015-2019. Available at https://www.eia.gov/electricity/data/eia861/.

Table 83. Percent of load assumed to be unhedged in Counterfactual #1

Year	ISO	CT	MA	ME	NH	RI	VT
2021	40%	27%	45%	47%	45%	46%	20%
2022	63%	43%	70%	75%	72%	73%	33%
2023	75%	54%	79%	94%	90%	91%	41%
2024	68%	48%	69%	91%	90%	76%	41%
2025	63%	38%	64%	88%	90%	73%	41%
2026	61%	39%	60%	88%	90%	73%	41%
2027	62%	43%	61%	89%	90%	73%	41%
2028	63%	46%	62%	89%	90%	74%	41%
2029	64%	47%	62%	89%	90%	74%	41%
2030	66%	55%	63%	89%	90%	75%	41%
2031	71%	76%	64%	90%	91%	75%	41%
2032	72%	76%	64%	90%	91%	76%	41%
2033	72%	77%	65%	90%	91%	76%	41%
2034	73%	77%	65%	91%	91%	77%	41%
2035	73%	77%	66%	91%	91%	77%	41%

Note: Because total energy demand varies for each counterfactual, and because assumptions on contracted MWh are fixed, these percentages vary for each counterfactual. See the AESC 2021 User Interface for detail on each counterfactual.

Decay assumptions

We assume three factors tend to reduce energy DRIPE as time passes after the initial effect on market prices:

1. **Resources respond to changes in 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.

2. **Demand elasticity.** Over time, customers might respond to lower energy prices by using somewhat more energy, pushing prices back up somewhat. We assume demand elasticities that start at 3 percent in 2021 and increase to 8 percent by 2026, where they are sustained through the study period.[248]

3. **Impact from binding RPS policies.** For every megawatt-hour not required due to energy efficiency, generation service providers will not need to procure a fraction of a REC from new renewable resources, assuming that these policies are "binding" (i.e., drive construction of new renewable resources in New England).[249] We assume that reducing load under conditions where RPS policies are binding will generally result in fewer renewables being built, partially offsetting the reduction in energy load. This percentage varies by state, year, and counterfactual.

[248] Elasticities are derived from Paul, A., et al. "A partial adjustment model of U.S. electricity demand by region, season, and sector." Resources for the Future. Published April 2009.

[249] For more discussion on binding RPS policies, see Chapter 7: *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* and Section 8.3: *Applying non-embedded costs*.

We calculate the aggregate decay effect in each year as the product of (a) one less the percent of load that is binding under the state's RPS policies, (b) one less the demand elasticity factor, and (c) one less the resource fade-out factor. This effect is shown in Table 84, for Counterfactual #1, for measures installed in 2021.

Table 84. Energy DRIPE decay factors for measures installed in 2021 in Counterfactual #1

Year	ISONE	CT	MA	ME	NH	RI	VT
2021	93%	96%	91%	96%	93%	96%	88%
2022	90%	93%	88%	93%	91%	93%	85%
2023	88%	92%	86%	92%	89%	92%	82%
2024	87%	90%	84%	90%	87%	90%	79%
2025	85%	88%	82%	88%	85%	88%	76%
2026	82%	85%	80%	85%	83%	85%	73%
2027	78%	82%	76%	82%	79%	82%	69%
2028	73%	76%	71%	76%	74%	76%	63%
2029	66%	69%	64%	69%	67%	69%	56%
2030	54%	57%	52%	57%	55%	57%	46%
2031	37%	39%	36%	39%	38%	39%	31%
2032	0%	0%	0%	0%	0%	0%	0%
2033	0%	0%	0%	0%	0%	0%	0%
2034	0%	0%	0%	0%	0%	0%	0%
2035	0%	0%	0%	0%	0%	0%	0%

Note: This decay schedule will vary for measures installed in other years, under other counterfactuals. See the AESC 2021 User Interface for detail on each counterfactual.

Energy DRIPE values

After combining the effects of the price shifts, unhedged demand, and decay, we are able to calculate the energy DRIPE benefits. Table 85 provides 15-year levelized energy DRIPE benefits for efficiency measures installed in 2021 using Equation 7 and Equation 8. These values may be multiplied by a MWh quantity (e.g., energy savings from energy efficiency or energy increases from electrification) to estimate the resultant DRIPE impact in dollars. Values are shown for measures installed in 2021; values for measures installed in other years may be calculated using the *AESC 2021 User Interface*.

Table 85. Energy DRIPE values for 2021 installations (2021 $ per MWh) for Counterfactual #1

	Year	Intrazonal (Own Zone)						Interzonal (Rest-of-Pool)					
		CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT
Winter off-peak	2021	$3.01	$9.25	$2.39	$2.11	$1.37	$0.42	$15.64	$9.09	$16.24	$16.45	$17.22	$18.11
	2022	$5.50	$16.68	$4.38	$3.91	$2.54	$0.77	$28.46	$16.72	$29.55	$29.89	$31.33	$32.96
	2023	$6.76	$18.66	$5.41	$4.82	$3.13	$0.93	$33.19	$20.59	$34.50	$34.92	$36.69	$38.71
	2024	$6.23	$16.75	$5.41	$4.98	$2.69	$0.94	$30.99	$19.82	$31.79	$32.06	$34.41	$35.98
	2025	$4.81	$15.49	$5.21	$4.93	$2.54	$0.92	$29.27	$18.00	$28.89	$29.01	$31.46	$32.89
	2026	$4.69	$13.99	$5.06	$4.76	$2.46	$0.87	$27.32	$17.44	$26.96	$27.11	$29.46	$30.86
	2027	$4.89	$13.30	$4.79	$4.49	$2.33	$0.80	$25.92	$16.91	$26.01	$26.17	$28.38	$29.70
	2028	$5.09	$13.07	$4.71	$4.40	$2.29	$0.77	$25.44	$16.84	$25.81	$25.98	$28.12	$29.43
	2029	$4.80	$12.29	$4.42	$4.10	$2.15	$0.70	$23.87	$15.77	$24.24	$24.43	$26.41	$27.65
	2030	$4.61	$10.27	$3.69	$3.40	$1.79	$0.57	$19.93	$13.71	$20.82	$20.99	$22.63	$23.67
	2031	$4.45	$7.23	$2.60	$2.38	$1.26	$0.39	$14.04	$10.80	$15.82	$15.96	$17.10	$17.84
Winter on-peak	2021	$3.94	$11.92	$3.04	$2.72	$1.79	$0.55	$20.13	$11.76	$21.00	$21.25	$22.21	$23.37
	2022	$6.64	$19.80	$5.12	$4.64	$3.07	$0.92	$33.75	$19.91	$35.22	$35.56	$37.21	$39.19
	2023	$7.78	$21.14	$6.03	$5.45	$3.61	$1.06	$37.56	$23.41	$39.25	$39.65	$41.59	$43.93
	2024	$7.17	$18.96	$6.01	$5.62	$3.10	$1.07	$35.01	$22.46	$36.12	$36.34	$38.92	$40.74
	2025	$5.52	$17.51	$5.78	$5.56	$2.92	$1.04	$33.01	$20.35	$32.76	$32.82	$35.51	$37.17
	2026	$5.54	$16.26	$5.78	$5.52	$2.92	$1.02	$31.70	$20.30	$31.47	$31.56	$34.23	$35.89
	2027	$6.00	$16.07	$5.68	$5.41	$2.87	$0.98	$31.25	$20.45	$31.56	$31.65	$34.25	$35.90
	2028	$5.81	$14.67	$5.18	$4.92	$2.62	$0.87	$28.49	$18.93	$29.09	$29.20	$31.54	$33.05
	2029	$5.39	$13.49	$4.79	$4.52	$2.37	$0.78	$26.16	$17.40	$26.74	$26.87	$29.06	$30.41
	2030	$5.20	$11.31	$4.01	$3.76	$1.99	$0.64	$21.92	$15.19	$23.06	$23.19	$25.00	$26.14
	2031	$5.02	$7.95	$2.82	$2.63	$1.39	$0.44	$15.43	$11.98	$17.53	$17.65	$18.90	$19.71
Summer off-peak	2021	$1.60	$4.90	$1.10	$1.05	$0.78	$0.20	$8.07	$4.62	$8.56	$8.59	$8.88	$9.42
	2022	$2.38	$7.17	$1.65	$1.58	$1.17	$0.30	$11.95	$6.92	$12.65	$12.68	$13.12	$13.93
	2023	$2.87	$7.86	$2.00	$1.91	$1.42	$0.35	$13.65	$8.36	$14.49	$14.52	$15.06	$16.04
	2024	$2.81	$7.49	$2.12	$2.09	$1.29	$0.38	$13.47	$8.49	$14.14	$14.11	$14.93	$15.77
	2025	$2.18	$6.98	$2.06	$2.09	$1.23	$0.37	$12.81	$7.74	$12.93	$12.84	$13.73	$14.49
	2026	$2.12	$6.27	$1.98	$2.00	$1.18	$0.35	$11.87	$7.46	$12.00	$11.92	$12.77	$13.51
	2027	$2.22	$6.02	$1.90	$1.91	$1.13	$0.33	$11.38	$7.31	$11.69	$11.63	$12.43	$13.14
	2028	$2.44	$6.23	$1.96	$1.96	$1.17	$0.33	$11.76	$7.68	$12.22	$12.17	$12.98	$13.73
	2029	$2.30	$5.84	$1.83	$1.82	$1.09	$0.30	$11.00	$7.16	$11.44	$11.40	$12.15	$12.85
	2030	$2.24	$4.95	$1.56	$1.54	$0.92	$0.25	$9.32	$6.33	$9.97	$9.95	$10.58	$11.17
	2031	$2.16	$3.49	$1.10	$1.07	$0.65	$0.17	$6.57	$5.02	$7.59	$7.58	$8.02	$8.44
Summer on-peak	2021	$2.89	$8.79	$1.81	$1.83	$1.46	$0.35	$14.35	$8.16	$15.39	$15.32	$15.73	$16.78
	2022	$4.03	$12.12	$2.55	$2.61	$2.07	$0.48	$19.99	$11.48	$21.42	$21.29	$21.88	$23.37
	2023	$4.46	$12.18	$2.83	$2.89	$2.29	$0.53	$20.89	$12.72	$22.47	$22.34	$22.99	$24.64
	2024	$4.40	$11.77	$3.04	$3.20	$2.12	$0.57	$20.89	$13.06	$22.20	$21.96	$23.09	$24.51
	2025	$3.45	$11.07	$2.97	$3.22	$2.03	$0.57	$20.02	$11.98	$20.48	$20.15	$21.39	$22.72
	2026	$3.55	$10.49	$3.03	$3.27	$2.07	$0.56	$19.58	$12.20	$20.08	$19.76	$21.01	$22.36
	2027	$3.93	$10.61	$3.06	$3.28	$2.08	$0.55	$19.76	$12.60	$20.59	$20.29	$21.53	$22.90
	2028	$3.79	$9.66	$2.78	$2.97	$1.89	$0.49	$17.97	$11.64	$18.94	$18.67	$19.79	$21.04
	2029	$3.58	$9.08	$2.61	$2.77	$1.78	$0.45	$16.85	$10.90	$17.79	$17.55	$18.58	$19.76
	2030	$3.51	$7.72	$2.22	$2.34	$1.51	$0.37	$14.33	$9.70	$15.57	$15.38	$16.25	$17.25
	2031	$3.44	$5.52	$1.59	$1.66	$1.08	$0.26	$10.26	$7.81	$12.03	$11.91	$12.52	$13.24

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

Table 86 provides the levelized value for energy DRIPE installed in each state, broken down between the value of price reductions in the state of installation (intrazonal) and in the rest-of-pool (interzonal). Intrazonal and interzonal values may be added to determine the total DRIPE effect.

Table 86. Seasonal energy DRIPE values for measures installed in 2021 (2021 $ per MWh)

Type	Season	Period	CT	MA	ME	NH	RI	VT
Intrazonal	Summer	On-Peak	$2.78	$7.41	$1.93	$2.04	$1.38	$0.35
		Off-Peak	$1.72	$4.56	$1.31	$1.29	$0.82	$0.23
	Winter	On-Peak	$4.34	$11.50	$3.68	$3.44	$1.95	$0.64
		Off-Peak	$3.72	$9.99	$3.26	$3.00	$1.67	$0.55
Interzonal	Summer	On-Peak	$13.23	$8.29	$14.05	$13.89	$14.58	$15.51
		Off-Peak	$8.27	$5.23	$8.66	$8.64	$9.13	$9.67
	Winter	On-Peak	$21.36	$13.71	$21.99	$22.13	$23.66	$24.82
		Off-Peak	$18.61	$11.91	$19.05	$19.21	$20.58	$21.57

Note: Values shown are levelized over 15 years.

9.3. Electric capacity DRIPE

This section describes our methodology and assumptions for capacity market DRIPE effects. If the capacity market were in equilibrium, and all the marginal sources of capacity had similar cost characteristics, reducing demand or adding capacity would not have much effect on capacity price. However, results from recent forward capacity auctions have shown that this is not the case (see discussion in Chapter 5: *Avoided Capacity Costs*). Instead, the marginal sources of capacity vary in price. The bid prices for individual units appear to have declined over time, as well. 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.[250] As a result, we can be certain that capacity price effects are both real and material.

AESC estimates two varieties of capacity DRIPE effects:

- Cleared DRIPE benefits, which are benefits of measures that clear in the ISO New England FCM
- Uncleared DRIPE benefits, which are benefits of measures that are not submitted into or otherwise do not clear in the ISO New England FCM

This section describes the methodology used to calculate both types of capacity DRIPE. We begin with a discussion of price shifts, then describe which components of regional demand these price shifts are eligible to be applied, then describe the methodologies for calculating benefits in the two categories of capacity DRIPE.

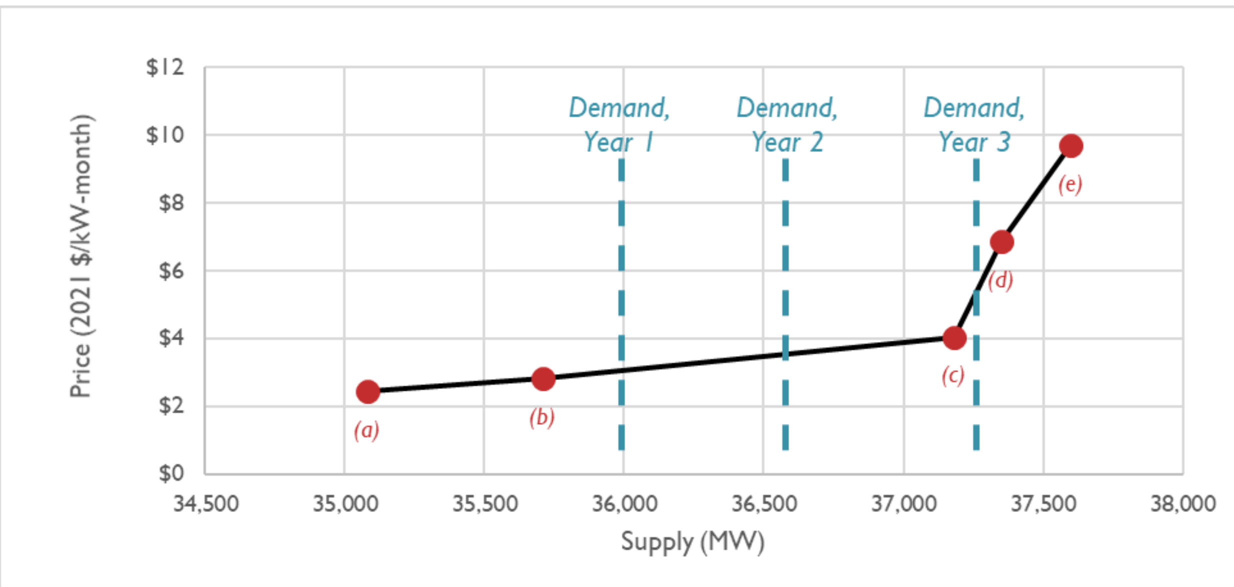
[250] FCM prices will be determined to a large extent by the prices at which existing resources choose to delist. By delisting, existing resources in New England are able to: (1) sell into another market such as New York, (2) shut down, or (3) operate in the energy market without obligations in the capacity market. New resources can defer implementation or operate in the energy market. Resources that do not clear in one FCA can bid into the subsequent auctions, including Annual Reconfiguration Auctions, or sell capacity bilaterally, such as to assume the capacity obligation of a resource that cleared.

Calculating price shifts in the capacity market

The "price shift" of capacity refers to how much the price of capacity (measures in $/kW-year per MW) changes in response to changes in demand. As in past AESC, we estimate price shifts for future years using the slope of the most recent capacity market auction (in the case of AESC 2021, this is FCA 15, conducted in February 2021), shifted to reflect the change in supply capacity that has occurred since that auction.

Figure 49 depicts the five known datapoints for supply and price in FCA 15.[251] The line segment between each one of these points has a slope, which is effectively the price shift used in AESC 2021. Depending on where demand crosses the supply curve, the clearing price will have a different associated price shift. For example, in Figure 49, demand in Year 1 and Year 2 will produce the same price shift. Demand in Year 3, however, crosses at a different line segment and will yield a different price shift. Practically speaking, the shallower the line segment, the lower the price shift's value is. Conversely, steeper line segments produce higher price shifts. See Table 87 for our estimates of the price shifts for each counterfactual.

Figure 49. Supply curve for FCA 15 with illustrative demand lines



Note: Demand lines are illustrative and do not represent actual or projected demand in any year.

[251] ISO New England. Last accessed March 11, 2021. *Forward Capacity market (FCA 15) Result.* Available at https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf

Table 87. Price shifts for capacity DRIPE (2021 $/kW-month per MW) in rest-of-pool region

	FCA	Counterfactual #1	Counterfactual #2	Counterfactual #3	Counterfactual #4
2021	12	$0.00038	$0.00038	$0.00038	$0.00038
2022	13	$0.00033	$0.00033	$0.00033	$0.00033
2023	14	$0.00051	$0.00051	$0.00051	$0.00051
2024	15	$0.00058	$0.00058	$0.00058	$0.00058
2025	16	$0.00058	$0.00058	$0.00058	$0.00058
2026	17	$0.00058	$0.00058	$0.00058	$0.00058
2027	18	$0.00083	$0.00083	$0.00083	$0.00083
2028	19	$0.00083	$0.00083	$0.00083	$0.00083
2029	20	$0.00083	$0.00083	$0.00083	$0.00083
2030	21	$0.00083	$0.00083	$0.00083	$0.00083
2031	22	$0.00083	$0.00083	$0.00083	$0.00083
2032	23	$0.00083	$0.00083	$0.00083	$0.00083
2033	24	$0.00083	$0.00083	$0.00083	$0.00083
2034	25	$0.01657	$0.01657	$0.01657	$0.01657
2035	26	$0.00083	$0.00083	$0.00083	$0.00083

Notes: Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Calculating capacity DRIPE

Price shifts are described in units of dollars-per-kW-month per MW (effectively, price per demand). To allow these numbers to be applied to any generic change in demand (e.g., from an energy efficiency measure), we multiply these values by the projected demand.

We calculate demand using two different sets of numbers. First, using the EnCompass model, we project future demand for each state and the region as a whole given the inputs described in Chapter 4: *Common Electric Assumptions*. Second, we multiply this by the fraction of demand that is unhedged. Unhedged demand is the quantity of electricity that has not already been procured ahead of time, and is thus subject to changes in the capacity market prices.

The unhedged percentage varies by state. 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.[252] For Vermont, we estimate hedged demand percentages based on data from the most recently available

[252] 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.

Green Mountain Power IRP, and we assume hedged demand share in the rest of the state is similar.[253] Specific data on hedged capacity for other states is less available. We rely on capacity contracts as published in FERC Form 1 and we assume half of all remaining vertically integrated demand is hedged as a proxy for the above-mentioned dynamics.

Table 88 describes the resulting unhedged capacity demand assumptions for Counterfactual #1. Values for Counterfactual #2 are lower, given its lower projections of load. Values for Counterfactual #3 and Counterfactual #4 are similar to Counterfactual #1. See the *AESC 2021 User Interface* for detail on all counterfactuals.

Table 88. Unhedged capacity for Counterfactual #1

	ISO	CT	MA	ME	NH	RI
2021	25,091	5,740	12,436	2,057	2,502	1,972
2022	25,797	5,841	12,712	2,108	2,556	2,015
2023	26,280	5,941	12,989	2,110	2,609	2,057
2024	26,458	5,949	13,099	2,132	2,629	2,072
2025	27,305	6,126	13,525	2,211	2,713	2,138
2026	26,877	5,982	13,350	2,183	2,674	2,106
2027	27,514	6,104	13,678	2,245	2,738	2,156
2028	27,988	6,184	13,930	2,294	2,786	2,194
2029	28,517	6,277	14,208	2,347	2,840	2,235
2030	28,967	6,347	14,443	2,401	2,885	2,273
2031	29,427	6,419	14,684	2,457	2,931	2,312
2032	29,832	6,469	14,952	2,486	2,965	2,336
2033	30,452	6,578	15,269	2,557	3,026	2,385
2034	31,004	6,668	15,555	2,624	3,081	2,430
2035	31,575	6,761	15,851	2,693	3,138	2,477

Notes: Data on clearing prices for other counterfactuals can be found in the AESC 2021 User Interface.

Price shifts and unhedged capacity quantities are two of the primary inputs used to estimate capacity DRIPE. The following sections describe the methodologies used to translate these values into (a) cleared capacity benefits and (b) uncleared capacity benefits.

Calculating cleared capacity DRIPE

AESC 2021, like previous AESC studies, utilizes a decay schedule for cleared capacity DRIPE. This schedule describes how these effects phase in and phase out.

First, we assume that all cleared measures have full DRIPE benefits in the first year they are installed. However, we assume that this effect does not last indefinitely. Over time, customers will respond to lower prices by using somewhat more energy, including at the peak. In addition, lower capacity prices may result in the retirement of some generation resources and termination of some demand-response resources, which will result in these resources being removed from the supply curve. Further, some new

[253] See *2018 Integrated Resource Plan*. Green Mountain Power. Chapter 8. Figure 8-20.

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).[254] As a result, we assume that the effects of DRIPE fade out over time. Based on expert judgement, we use the same assumption used in prior AESC studies, wherein the phase-out is linear over time, reaching an effect of zero in the seventh year. We assume that measures with shorter lifetimes use the same decay schedule, rather than a compressed decay schedule or some other alternative. This is because the phase-out of DRIPE effects is based on market dynamics, rather than the features of individual measures.

Table 89 shows the decay schedule used for cleared capacity measures installed in 2021. Measures installed in later years have the same decay schedule, but shifted by one or more years.

Table 89. Decay schedule used for cleared capacity for measures installed in 2021

	Decay	1- Decay
2021	0%	100%
2022	17%	83%
2023	33%	67%
2024	50%	50%
2025	67%	33%
2026	83%	17%
2027	100%	0%
2028	100%	0%
2029	100%	0%
2030	100%	0%
2031	100%	0%
2032	100%	0%
2033	100%	0%
2034	100%	0%
2035	100%	0%

After calculating this decay schedule, we calculate cleared capacity DRIPE as using the formulas described in Equation 9 (for interzonal DRIPE) and Equation 10 (for intrazonal). Interzonal DRIPE is calculated by multiplying the price shift for a given year by the unhedged capacity quantity for a given state, by one minus the decay percentage for that year. Meanwhile, intrazonal DRIPE uses the exact same calculation, except replaces the unhedged capacity quantity for the given state with the unhedged capacity quantity for the rest of the region (less the state in question).

Equation 9. Calculation of interzonal (zone-on-zone) cleared capacity DRIPE

$$Capacity\ DRIPE_{\substack{Zone\ Z\ |\ Zone\ Z \\ Period\ P}} = \left[Price\ Shift\ \times Hedged\ Capacity_{\substack{Zone\ Z \\ Period\ P}}\right] \times (1 - Decay)$$

[254] We note, however, that the historical record of (a) retirements and (b) cancelation of planned generation does not show any clear association with falling capacity prices.

Equation 10. Calculation of intrazonal (zone-on-rest-of-pool) cleared capacity DRIPE

$$Capacity\ DRIPE_{\substack{ROP\ |\ Zone\ Z \\ Period\ P}} = \left[Price\ Shift \times \left(Hedged\ Capacity_{\substack{ISO \\ Period\ P}} - Hedged\ Capacity_{\substack{Zone\ Z \\ Period\ P}}\right)\right] \times (1 - Decay)$$

Table 90 shows cleared capacity DRIPE for each region for measures that are installed in 2021.

Table 90. Cleared capacity DRIPE by year for measures installed in 2021 (2021 $ per kW-year)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	$116	$26	$57	$9	$12	$9	$2	$89	$58	$106	$104	$106	$114
2022	$86	$19	$42	$7	$9	$7	$2	$66	$44	$79	$77	$79	$84
2023	$108	$24	$53	$9	$11	$8	$2	$84	$55	$99	$97	$100	$106
2024	$92	$21	$46	$7	$9	$7	$2	$72	$47	$85	$83	$85	$90
2025	$63	$14	$31	$5	$6	$5	$1	$49	$32	$58	$57	$58	$62
2026	$32	$7	$16	$3	$3	$3	$1	$25	$16	$29	$29	$29	$31
2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2029	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2030	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2031	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2032	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2033	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2034	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2035	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15-year levelized	**$34**	**$8**	**$17**	**$3**	**$3**	**$3**	**$1**	**$27**	**$17**	**$32**	**$31**	**$32**	**$34**

Calculating uncleared capacity DRIPE

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. 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.

To calculate uncleared capacity DRIPE, we utilize a modified version of the same phase-in / phase-out schedule described above in Section 5.2: *Uncleared capacity calculations*. As with uncleared capacity, we assume that uncleared capacity DRIPE effects do not appear until five years after a measure is installed, and that they persist at various magnitudes and lengths of time depending on the measure's lifetime. However, uncleared capacity DRIPE differs in that we also assume that DRIPE effects decay over time, following the same decay schedule described in Table 89.

As with uncleared capacity, the calculations of uncleared capacity DRIPE also utilize estimates of reserved margin and scaling factors (also described above in Section 5.2: *Uncleared capacity calculations*).

To estimate uncleared capacity DRIPE, we use the following calculations:

- For intrazonal (zone-on-zone) uncleared capacity DRIPE in a particular state and year, we calculate the product of (a) the state's unhedged demand, (b) the price shift for that year, (c) the effect-and-decay schedule that matches the measure's lifetime, and (d) the scaling factor, if relevant. Unlike cleared capacity DRIPE, this value is then multiplied by one plus the reserve margin to reflect the fact that since the measure is uncleared, it is capable of avoiding some reserve margin.[255]
- For interzonal (zone-on-rest-of-pool) uncleared capacity DRIPE for a particular state and year, we calculate the product of (a) regional unhedged demand minus the state's unhedged demand, (b) the price shift for that year, (c) the effect-and-decay schedule that matches the measure's lifetime, and (d) the scaling factor, if relevant. This value is then multiplied by one plus the reserve margin.

Table 90 shows uncleared capacity DRIPE for each region for measures that are installed in 2021, assuming a measure life of 10 years. Here, we observe uncleared capacity DRIPE benefits that are higher than cleared capacity DRIPE benefits primarily because this particular example describes avoided costs for a measure with a 10-year life. Measures with this program lifetime provide substantial uncleared DRIPE benefits in the mid-2020s and early 2030s, but do not provide cleared capacity DRIPE benefits in those same years.

[255] As the measure is uncleared, it is effectively "counted" in the demand side of the capacity auction (i.e., within the load forecast). In contrast, measures that are cleared are effectively treated the same as conventional power plants (i.e., supply), and through the auction effectively require the purchase of some extra amount of capacity to act as a reserve margin.

Table 91. Uncleared capacity DRIPE by year for measures installed in 2021 (2021 $ per kW-year)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2022	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2023	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2024	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2026	$64	$14	$32	$5	$6	$5	$1	$49	$32	$58	$57	$59	$62
2027	$140	$31	$70	$11	$14	$11	$3	$109	$71	$129	$126	$129	$137
2028	$181	$40	$90	$15	$18	$14	$4	$141	$91	$166	$163	$167	$177
2029	$211	$47	$105	$17	$21	$17	$5	$165	$106	$194	$190	$195	$207
2030	$198	$43	$99	$16	$20	$16	$4	$155	$99	$182	$178	$182	$194
2031	$146	$32	$73	$12	$15	$11	$3	$114	$73	$134	$131	$134	$143
2032	$91	$20	$46	$8	$9	$7	$2	$71	$45	$83	$82	$84	$89
2033	$52	$11	$26	$4	$5	$4	$1	$41	$26	$48	$47	$48	$51
2034	$471	$101	$236	$40	$47	$37	$10	$370	$235	$431	$424	$434	$461
2035	$6	$1	$3	$1	$1	$0	$0	$5	$3	$6	$6	$6	$6
15-year levelized	**$102**	**$22**	**$51**	**$8**	**$10**	**$8**	**$2**	**$79**	**$51**	**$93**	**$92**	**$94**	**$100**

Note: This chart assumes a measure life of 10 years. Measures with other measure lives will have completely different uncleared capacity DRIPE effects. See the AESC 2021 User Interface for more information.

Important caveats for applying uncleared capacity DRIPE values

Uncleared capacity DRIPE is different than many other avoided cost categories. Because uncleared capacity DRIPE describes an effect that fades out over time due to the market's responses to that effect, users should sum avoided costs over the entire study period, regardless of any one measure's lifetime. For example, the avoided costs of a 1 MW measured installed in 2021 would be equal to the sum of the values from 2021 through 2055, regardless of whether that measure had a 1-year measure life or a 30-year measure life.[256]

Uncleared resources affect the load forecast only to the degree that these resources provide load reductions on the hours used in the load forecast regression. Some resources—such as demand response resources—may be active only on one or some of the hours used in the load forecast. As a result, these resources would provide a diminished uncleared capacity benefit. We recommend that program administrators apply a scaling factor to the benefits detailed in Table 91 to account for this effect. See Appendix K: *Scaling Factor for Uncleared Resources* for more information on how this scaling factor is calculated and how it can be applied.

[256] We note that this is the same approach used for summing avoided costs for uncleared capacity and uncleared capacity DRIPE, but no other avoided cost categories.

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. This natural gas price reduction effect is natural gas DRIPE. The price for natural gas—and associated benefits—can be broken into two components:

1. The supply component, determined by North American demand and supply conditions on a largely annual basis.
2. 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 for other users, especially electric generators.

Importantly, only the supply component of natural gas DRIPE is used in cost-effectiveness screening of gas measures. This is because LDCs and most other suppliers of gas to the end-use rely primarily on firm long-term contracts for pipeline and storage capacity to allow for delivery of natural gas. As a result, the basis DRIPE effect benefits only electric customers.

Natural gas supply DRIPE

This section focuses on the calculation of natural gas supply DRIPE. This is the DRIPE effect that is applied to end-use measures that produce natural gas savings.

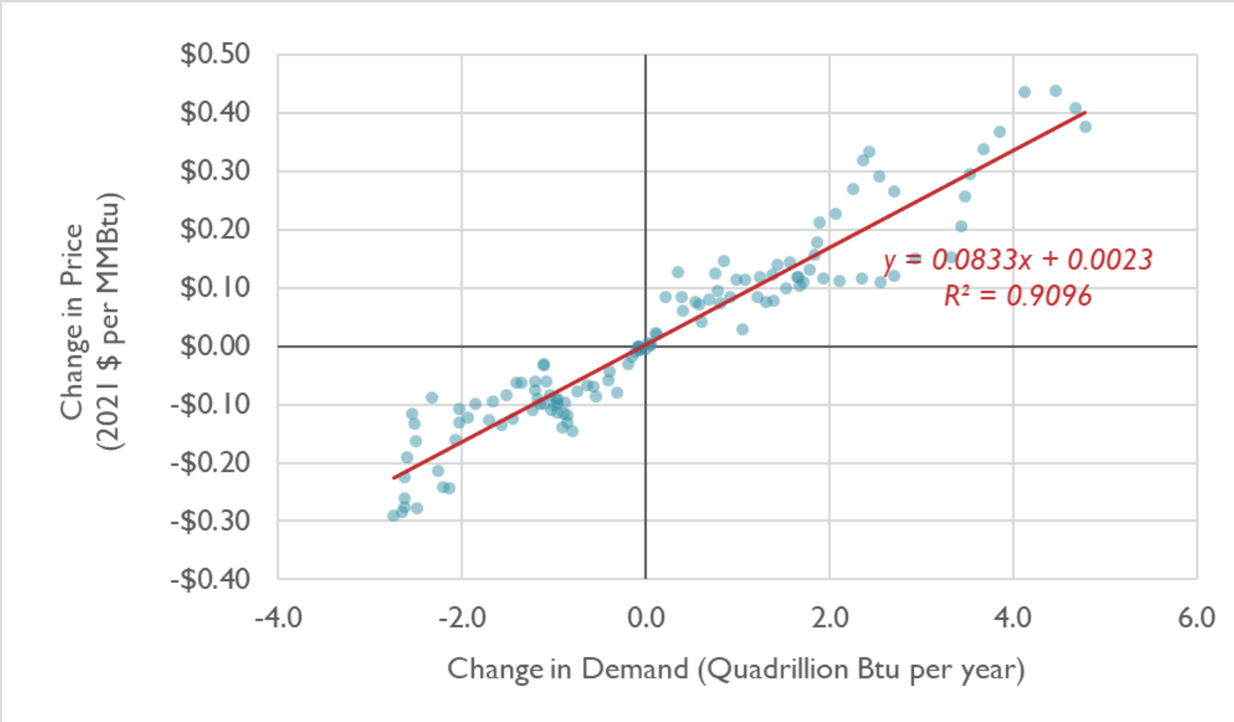
Calculating elasticities

Elasticity describes how prices of a commodity respond to changes in demand. In AESC 2018, we relied on a literature review of recent estimates of natural gas elasticities (including both top-down and bottom-up empirical estimates). For AESC 2021, we instead rely on a calculation of the implied response of natural gas prices to supply changes observed in different scenarios modeled in EIA's AEO 2021.

Figure 50 compares annual data points from AEO 2021. Each data point represents the difference in both prices and demand for one AEO side scenario relative to the price and demand for natural gas in AEO 2021 Reference case for the same year. This figure includes datapoints from four different AEO side scenarios: the High economic growth, Low economic growth, High renewable cost, and Low renewable cost cases. This analysis encompasses all years from 2020 through 2050. A linear regression of this dataset provides a slope that indicates how changes in price are related to changes in demand.

Overall, we find that reducing demand by one quadrillion Btu reduces EIA's estimate of the market price by $0.083 per MMBtu in 2021 dollars. This is about half of the AESC 2018 value of $0.16/MMBtu per quadrillion Btu/year (in 2021 dollars).

Figure 50. Effect of changing gas demand on gas price



Note: Deltas compare annual prices and demand in four AEO 2021 scenarios versus the AEO 2021 Reference case.

Calculating natural gas supply DRIPE

As with electricity 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. According to AEO 2021, each year, New England is expected to consume 0.5 quadrillion Btu for non-electric uses.[257] Multiplying this quantity by the price shift ($0.083/MMBtu per quadrillion Btu) yields a natural gas supply DRIPE effect of $0.05 per MMBtu. The quantity of gas consumed for non-electric uses changes over time, and among states. Between 2021 and 2035, AEO 2021 estimates that non-electric gas demand will increase by about 16 percent. Demand in each state is projected based on recent historical observations from 2014 through 2018. Vermont, for example, is projected to consume about 0.01 quadrillion Btu while Massachusetts is projected to consume about 0.3 quadrillion Btu. These differences yield different DRIPE effects for each state.

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

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[257] Gas supply DRIPE is applied to gas efficiency measures which displace consumption of gas that has been purchased by LDCs. As a result, we use non-electric consumption for this calculation.

the effect of demand on the marginal cost of extraction for a finite resource. If anything, lower gas usage in 2021 will leave more low-cost gas in the ground to meet demand in 2022, causing the DRIPE effect to accumulate over time.

However, we do assume that only a portion of consumption is responsive to DRIPE as a result of short-term contracts for gas. In Year 1, we assume that half of all gas demand is tied up in short-term contacts and is thus not impacted by DRIPE effects. This decreases to 20 percent in Year 2 and is assumed to fade away entirely in Year 3. Table 92 describes this impact schedule for measures that are installed in 2021. Measures installed in subsequent years would see these values shifted by one or more years. This is the same assumption used for short-term energy contracts for energy DRIPE (see Section 9.2: *Electric energy DRIPE*).

Table 92. Share of demand that is responsive to natural gas supply DRIPE

Year	Share of demand not impacted by DRIPE	Share of demand impacted by DRIPE
2021	50%	50%
2022	20%	80%
2023	0%	100%
…	…	…
2035 and later	0%	100%

Note: Values shown are for measures installed in 2021. Measures installed in 2022 would see these effects shifted by one year, measures installed in 2023 would see these effects shifted by two years, and so on.

Natural gas supply DRIPE values

Table 93 depicts the value of demand reduction for each state. This is calculated by obtaining the product of (a) the price shift (in 2021 $/MMBtu per quadrillion Btu), (b) the state's non-electric natural gas consumption, and (c) the share of demand that is responsive to natural gas supply effects.[258] Table 93 also shows the DRIPE effects for each state on the rest of the region. These values are calculated by subtracting the own-state value from the New England total in each year.

Using this table, we can see estimate the benefit for a reduction in gas use in each year. For example, a 1 MMBtu reduction in natural gas demand in 2023 yields a gas supply DRIPE benefit of $0.045 for New England as a whole.

AESC 2021's gas supply DRIPE estimates are lower than those found in AESC 2018, mostly due to lower price shift ($0.083/MMBtu per quadrillion Btu, down from $0.158/MMBtu per quadrillion Btu). Other changes are due to differences in historical gas consumption and projected gas consumption across the six states.

[258] Note that this consumption (and everything related to natural gas supply DRIPE) is independent of the natural gas price and avoided cost forecasts developed in Chapter 0:

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Table 93. Natural gas supply DRIPE benefit (2021 $ per MMBtu)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.020	0.005	0.011	0.001	0.001	0.002	0.000	0.015	0.009	0.019	0.019	0.019	0.020
2022	0.036	0.009	0.019	0.002	0.002	0.003	0.001	0.027	0.016	0.033	0.034	0.033	0.035
2023	0.045	0.011	0.024	0.003	0.002	0.003	0.001	0.034	0.021	0.042	0.043	0.042	0.044
2024	0.046	0.011	0.025	0.003	0.002	0.003	0.001	0.034	0.021	0.043	0.043	0.042	0.045
2025	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2026	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2027	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2028	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.042	0.045
2029	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.043	0.045
2030	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.043	0.044	0.043	0.045
2031	0.046	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.045
2032	0.047	0.011	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.045
2033	0.047	0.012	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.046
2034	0.047	0.012	0.025	0.003	0.002	0.004	0.001	0.035	0.021	0.044	0.044	0.043	0.046
2035	0.047	0.012	0.025	0.003	0.002	0.004	0.001	0.035	0.022	0.044	0.045	0.043	0.046
10-year levelized	**0.044**	**0.011**	**0.024**	**0.003**	**0.002**	**0.003**	**0.001**	**0.033**	**0.020**	**0.041**	**0.041**	**0.040**	**0.043**

Note: Values differ across states because states vary in terms of size of non-electric gas consumption.

Natural gas basis DRIPE

Reductions in annual gas use will not only reduce the supply cost of natural gas, but also the basis. The basis is the price differential between the wholesale market price of gas in New England and the prices in the supply areas (sometimes called the "transportation" cost of natural gas). Since LDCs and most other suppliers of gas to the end-use rely primarily on firm long-term contracts for pipeline and storage capacity to allow for delivery of natural gas, the basis DRIPE effect benefits only electric customers and is thus only used in G-E cross-DRIPE and below in E-G-E cross-DRIPE (see more below in Section 9.5: *Cross-fuel market price effects*).

Calculating elasticities

The majority of the price differential for natural gas in New England is attributable to constraints on gas delivery capacity into New England from the Mid-Atlantic region. As a result, our analysis focuses on the basis 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.[259]

[259] To be clear, this calculation of DRIPE ignores effects from gas delivered to New England directly from Canada or from LNG.

Using data spanning three winters (December 2017 through March 2020), we examine prices and demand for gas to determine price shifts over different periods of time. First, we utilize daily natural gas delivery data for the Algonquin Pipeline and Tennessee Gas Pipeline to determine the total amount of gas delivered to New England from the south.[260] For each day, we calculate the aggregate surplus capacity for these two pipelines. Separately, we also estimate the price paid for gas flowing each day at both the TETCO M3 Hub and the Algonquin Citygate.[261] The difference between these two values is the assumed basis for natural gas in New England.

Next, we assess a set of regressions of this surplus and basis data to determine what the price shift is at different times of the year. The slope of a linear regression describes the price shift. Table 94 describes the time periods and estimated price shifts. Note the use of two different "winter" periods and two different "summer" periods—one for electricity and one for gas. The seasonal assignments for the electric seasons are based on ISO New England's definition, while the gas seasons are consistent with the analysis in Chapter 0:

[260] Spectra Energy. Last accessed March 11, 2021. "Algonquin Gas Transmission." *Spectraenergy.com*. Available at https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG.

Tennessee Gas Pipeline Company. Last accessed March 11, 2021. "Informational Postings: Point Capacity." *Kindermorgan.com*. Available at https://pipeline2.kindermorgan.com/Capacity/OpAvailPoint.aspx?code=TGP.

[261] Natural Gas Intelligence. Last accessed March 11, 2021. "Texas Eastern M-3, Delivery Daily natural Gas Price Snapshot." *Naturalgasintel.com*. Available at https://www.naturalgasintel.com/data-snapshot/daily-gpi/NEATETM3DEL/.

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Table 94. Gas basis price shifts by season

Season	Months included	Basis price shift (2021 $/MMBtu per BBtu/day)
Summer, electric	June through September	$0.00035
Winter, electric	October through May	$0.00203
Summer, gas	April through October	$0.00132
Winter, gas	November through March	$0.00328
Annual	**All months**	**$0.00180**

Over time, we assume that these basis price shifts decay as a result of a rebound effect (e.g., consumers using more gas given that it is cheaper), response of existing generation to price changes (i.e., gas units stay online longer and generate more electricity because of lower gas prices), and response of new generation to price changes (i.e., as prices remain low, there is less pressure to switch to newer, more efficient gas units). The combined effect of these drivers results in the decay schedule described in Table 95. Note that this schedule is for measures installed in 2021; measures installed in later years (e.g., 2021, 2022, and so on) use this same decay schedule but shifted by one year.

Table 95. Percent of gas basis decayed by year for measures installed in 2021

	Gas Basis Decay (%)
2021	1.3%
2022	4.1%
2023	6.8%
2024	16.3%
2025	25.4%
2026	46.8%
2027	67.0%
2028	76.0%
2029	84.5%
2030	92.5%
2031	100.0%
2032	100.0%
2033	100.0%
2034	100.0%
2035	100.0%

We then apply these decay percentages to the price shifts described above. Table 96 shows the decayed basis values for a measure installed in 2021, with the supply gas DRIPE values (which are not decayed) for comparison. All values have been converted in to $/MMBtu per Quadrillion Btu terms, as these are otherwise very small numbers.

Table 96. Decayed natural gas DRIPE values (2021 $/MMBtu per Quadrillion Btu reduced)

	Basis					***Supply***
	Electricity Summer	*Electricity Winter*	*Gas Summer*	*Gas Winter*	Annual	*Annual*
2021	0.0028	0.0083	0.0061	0.0214	0.0049	0.0001
2022	0.0028	0.0080	0.0059	0.0208	0.0047	0.0001
2023	0.0027	0.0078	0.0058	0.0202	0.0046	0.0001
2024	0.0024	0.0070	0.0052	0.0182	0.0041	0.0001
2025	0.0021	0.0062	0.0046	0.0162	0.0037	0.0001
2026	0.0015	0.0045	0.0033	0.0116	0.0026	0.0001
2027	0.0009	0.0028	0.0020	0.0072	0.0016	0.0001
2028	0.0007	0.0020	0.0015	0.0052	0.0012	0.0001
2029	0.0004	0.0013	0.0010	0.0034	0.0008	0.0001
2030	0.0002	0.0006	0.0005	0.0016	0.0004	0.0001
2031	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2032	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2033	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2034	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2035	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001

In New England, basis benefits are significantly larger than supply benefits, for two reasons. First, New England demand is only a small portion of North American demand, so a percentage change in regional load has a much smaller percentage effect on continent-wide demand. Second, while gas producers can increase production from year to year, pipeline constraints are much less flexible, requiring years of planning, siting, permitting and most importantly contracting.

Basis price shifts are not outright applied to any measures. Instead, they are combined with several other factors and used to calculate cross-DRIPE. See "G-E cross-DRIPE" and "E-G-E cross-DRIPE" subsections below in Section 9.5: *Cross-fuel market price effects*. See these subsections for comparisons of AESC 2021 values with analogous values from AESC 2018.

9.5. 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 ($/MWh)** 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 ($/MMBtu)** measures the benefits to gas consumers from a reduction in electricity demand. Electric power accounts for about one-third of the region's gas demand, so reducing electricity demand should reduce gas prices.
3. **Electric-to-gas-to-electric (E-G-E) cross-DRIPE ($/MWh)** 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. Electric energy DRIPE captures the first benefit, while 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.

Electric-to-gas (E-G) 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.

To calculate E-G cross-DRIPE, we utilize the supply gas price shift calculated in Section 9.4: *Natural gas DRIPE*: $0.083/MMBtu per quadrillion Btu. Next, we convert this price shift's units into $-per-MWh per quadrillion Btu so that it may be applied to MWh savings. We do this by relying on data about the marginal heat rate for emitting plants as reported by ISO New England.[262] According to this data, the marginal emitting plant heat rate is 7.74 MMBtu per MWh.[263] If we scale this to reflect the amount of time gas is expected to be on the margin in the energy market, we estimate a marginal gas heat rate of 6.43 MMBtu per MWh.[264] This value can then be multiplied by the price shift to produce an estimate of $0.54/MWh per quadrillion Btu (see Equation 11).

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[262] ISO New England. May 2020. *Electric Generator Air Emissions Report.* Available at https://www.iso-ne.com/static-assets/documents/2020/05/2018_air_emissions_report.pdf.

[263] Id, Section 5.3.2.2.

[264] According to ISO New England, from 2014 to 2018, natural gas plants and pumped storage plants (which are generally powered by marginal units) were marginal 83 percent of the time (see 2018 Air Emissions Report, Figure 4-7).

Equation 11. Price shift in dollar-per-MWh terms

$$Dollar\ per\ MWh\ price\ shift = dollar\ per\ MMBtu\ price\ shift \times marginal\ gas\ heat\ rate$$

$$= \frac{\frac{\$0.083}{MMBtu}}{Quadrillion\ Btu} \times \frac{6.43\ MMBtu}{MWh} = \frac{\frac{\$0.54}{MWh}}{Quadrillion\ Btu}$$

To determine E-G DRIPE, we then follow the same overall process used to estimate natural gas supply DRIPE. For each year and state, we calculate the product of (a) estimated natural gas consumption, (b) the estimated share of consumption that is DRIPE-responsive (see Table 92), and (c) the price shift.

Table 97. Electric-to-gas (E-G) cross-DRIPE benefit (2021 $ per MWh)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.129	0.032	0.070	0.008	0.006	0.010	0.003	0.097	0.059	0.121	0.123	0.119	0.126
2022	0.229	0.057	0.124	0.014	0.011	0.018	0.005	0.173	0.105	0.215	0.218	0.212	0.224
2023	0.291	0.072	0.157	0.018	0.015	0.022	0.007	0.219	0.133	0.273	0.276	0.268	0.284
2024	0.293	0.072	0.158	0.018	0.015	0.022	0.007	0.221	0.135	0.275	0.278	0.271	0.286
2025	0.295	0.073	0.159	0.018	0.015	0.023	0.007	0.222	0.135	0.276	0.280	0.272	0.288
2026	0.295	0.073	0.159	0.018	0.015	0.023	0.007	0.222	0.135	0.277	0.280	0.272	0.288
2027	0.295	0.073	0.159	0.018	0.015	0.023	0.007	0.222	0.135	0.277	0.280	0.272	0.288
2028	0.296	0.073	0.160	0.018	0.015	0.023	0.007	0.222	0.136	0.277	0.281	0.273	0.289
2029	0.296	0.073	0.160	0.018	0.015	0.023	0.007	0.223	0.136	0.278	0.281	0.274	0.289
2030	0.297	0.073	0.161	0.018	0.015	0.023	0.007	0.224	0.137	0.279	0.282	0.275	0.290
2031	0.298	0.074	0.161	0.018	0.015	0.023	0.007	0.224	0.137	0.280	0.283	0.275	0.291
2032	0.299	0.074	0.162	0.019	0.015	0.023	0.007	0.225	0.137	0.280	0.284	0.276	0.292
2033	0.300	0.074	0.162	0.019	0.015	0.023	0.007	0.225	0.138	0.281	0.284	0.277	0.292
2034	0.300	0.074	0.162	0.019	0.015	0.023	0.007	0.226	0.138	0.282	0.285	0.277	0.293
2035	0.301	0.074	0.163	0.019	0.015	0.023	0.007	0.227	0.138	0.283	0.286	0.278	0.294
15-year levelized	**0.280**	**0.069**	**0.151**	**0.017**	**0.014**	**0.021**	**0.007**	**0.211**	**0.129**	**0.263**	**0.266**	**0.259**	**0.273**

Note: Values differ across states because states vary in terms of size of non-electric gas consumption.

Using this table, we can see estimate the benefit for a reduction in gas use in each year. For example, a 1 MWh reduction in electricity demand in 2023 yields an E-G cross-DRIPE benefit of $0.291 for New England as a whole. As with other DRIPE categories, zone-on-rest-of-region DRIPE benefits for each year are calculated for each state by subtracting the own-zone value for a given state from the New England-wide value.

As with gas supply DRIPE, AESC 2021's gas supply DRIPE estimates are lower than those found in AESC 2018, mostly due to lower price shift ($0.083/MMBtu per quadrillion Btu, down from $0.158/MMBtu per quadrillion Btu). Other changes are due to differences in historical gas consumption and projected gas consumption across the six states.

Gas-to-electric (G-E) cross-DRIPE

Just as reductions in electricity demand can produce benefits to gas consumers, so too can reductions in gas demand benefit electric customers. Because this effect changes seasonally, we provide separate DRIPE benefits for annual and winter periods. Annual DRIPE benefits may be best applied to measures that provide savings throughout the year (such as hot water heating efficiency measures) while winter benefits may be best applied to measures that provide savings during the winter only (such as space heating efficiency measures).

To calculate G-E cross-DRIPE values, we first begin with the total price shifts described in Table 96. To calculate the price shift for each season, we add the supply price shift (which does not vary by season) to the basis price shift (which does vary by season). Because the gas basis price shift decays but the gas supply price shift does not, by 2031, the "total" price shift for any seasons is equal to the supply price shift component.

Next, these values undergo a unit conversion. We multiply these price shifts (measured in dollar-per-MMBtu per quadrillion Btu) by the heat rate derived above in the E-G cross-DRIPE section (which is measured in MMBtu per MWh). This translation yields price shifts in dollar-per-MWh per MMBtu.

These price shifts are multiplied by each state's unhedged energy to estimate total DRIPE benefits. For each state, the "energy" is the quantity of electricity demand (in MWh) in the state in question, consumed during the relevant period (e.g., winter, gas), under a particular counterfactual. This total quantity of energy is scaled by the portion of energy that is assumed to be unhedged in each state (i.e., the portion of energy purchases not expected to be subject to the spot market). This unhedged assumption is the same used in energy DRIPE, described above in Table 83. Because system load changes across counterfactuals, the unhedged percentage also changes.

Table 98 summarizes the resulting G-E cross-DRIPE values. For annual effects, we utilize the annual price shift; for winter effects, we rely on gas winter period price shifts.

Table 98. Gas-to-electric cross-fuel heating DRIPE, 2021 gas efficiency installations (2021 $ per MMBtu) for Counterfactual #1

		Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
		NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
Annual (e.g., water heating)	2021	1.45	0.24	0.73	0.17	0.16	0.11	0.03	1.21	0.72	1.28	1.29	1.34	1.42
	2022	2.19	0.36	1.09	0.26	0.25	0.17	0.05	1.82	1.10	1.92	1.94	2.01	2.14
	2023	2.52	0.44	1.19	0.32	0.30	0.21	0.06	2.08	1.33	2.20	2.22	2.31	2.46
	2024	2.03	0.35	0.93	0.28	0.27	0.16	0.05	1.68	1.10	1.76	1.76	1.88	1.98
	2025	1.68	0.24	0.77	0.24	0.24	0.13	0.04	1.43	0.90	1.44	1.43	1.54	1.63
	2026	1.16	0.17	0.51	0.17	0.17	0.10	0.03	0.98	0.64	0.99	0.99	1.06	1.13
	2027	0.73	0.12	0.32	0.11	0.11	0.06	0.02	0.61	0.41	0.62	0.62	0.67	0.71
	2028	0.52	0.09	0.23	0.08	0.07	0.04	0.01	0.43	0.29	0.44	0.45	0.48	0.51
	2029	0.32	0.06	0.14	0.05	0.05	0.03	0.01	0.27	0.18	0.27	0.28	0.30	0.31
	2030	0.15	0.03	0.06	0.02	0.02	0.01	0.00	0.12	0.09	0.13	0.13	0.14	0.15
	2031	0.02	0.01	0.01	0.00	0.00	0.00	0.00	0.02	0.01	0.02	0.02	0.02	0.02
	2032	0.00	0.00	0.00	0.00	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	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	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	0.00	0.00	0.00	0.00
Winter (e.g., space heating)	2021	2.66	0.44	1.33	0.32	0.30	0.20	0.06	2.21	1.32	2.34	2.36	2.46	2.59
	2022	4.00	0.67	1.99	0.49	0.46	0.31	0.09	3.33	2.01	3.52	3.54	3.70	3.91
	2023	4.61	0.81	2.18	0.59	0.56	0.37	0.11	3.80	2.43	4.02	4.05	4.24	4.50
	2024	3.72	0.64	1.70	0.51	0.50	0.28	0.10	3.08	2.02	3.21	3.22	3.44	3.62
	2025	3.06	0.45	1.41	0.44	0.44	0.23	0.08	2.61	1.65	2.62	2.62	2.83	2.98
	2026	2.10	0.32	0.93	0.31	0.31	0.17	0.06	1.78	1.17	1.79	1.79	1.94	2.04
	2027	1.30	0.21	0.57	0.19	0.19	0.10	0.03	1.09	0.73	1.11	1.11	1.20	1.27
	2028	0.92	0.16	0.40	0.13	0.13	0.07	0.02	0.76	0.52	0.78	0.78	0.85	0.89
	2029	0.55	0.10	0.24	0.08	0.08	0.04	0.01	0.46	0.31	0.47	0.47	0.51	0.54
	2030	0.24	0.05	0.10	0.03	0.03	0.02	0.01	0.19	0.14	0.20	0.21	0.22	0.23
	2031	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01
	2032	0.00	0.00	0.00	0.00	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	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	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	0.00	0.00	0.00	0.00

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

This table indicates that the annual New England-wide value of G-E cross-DRIPE for 2021 is $1.45 per MMBtu. The winter value ($2.66 per MMBtu) is nearly twice as large because of the higher basis values in the winter months. Importantly, since electricity generation everywhere in New England serves electricity demand throughout New England, the cross-price effect on electric consumers in a given state is not dependent on the amount of gas burned for electric generation in that same state. For each state and year, the zone-on-Rest-of-Pool benefit equals the difference between the ISO-wide benefit and the zonal benefit.

Table 99 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2018 and AESC 2021. As with other DRIPE categories relying on the price shift of natural gas supply, avoided costs for this category are lower in AESC 2021, compared to AESC 2018. This is primarily due to the reduced natural gas supply price shift, but it is also due to differences in projected loads and gas bases price shifts.

Table 99. Comparison of levelized gas-to-electric (G-E) cross-DRIPE benefits (2021 $ per MMBtu)

	ISO NE	CT	MA	ME	NH	RI	VT
Annual							
AESC 2018	2.73	0.58	1.33	0.27	0.29	0.20	0.06
AESC 2021	1.29	0.21	0.61	0.17	0.17	0.10	0.03
Difference ($)	-1.44	-0.37	-0.73	-0.10	-0.12	-0.10	-0.03
Difference (%)	-53%	-64%	-54%	-38%	-42%	-48%	-47%
Winter							
AESC 2018	5.03	1.07	2.45	0.50	0.53	0.36	0.11
AESC 2021	2.34	0.39	1.10	0.31	0.30	0.18	0.06
Difference ($)	-2.68	-0.68	-1.35	-0.19	-0.22	-0.18	-0.05
Difference (%)	-53%	-64%	-55%	-38%	-42%	-50%	-45%

Note: All values are levelized over 10 years.

Electric-to-gas-to-electric (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.

To calculate E-G-E cross DRIPE, we begin with the price shifts described above in Table 96. As with G-E cross-DRIPE, to calculate the price shift for each season, we add the supply price shift (which does not vary by season) to the basis price shift (which does vary by season). Because the gas basis price shift decays but the gas supply price shift does not, by 2031, the "total" price shift for is simply equal to the supply price shift component.

Next, these values undergo a unit conversion. Just as with G-E cross-DRIPE, we multiply these price shifts (measured in dollar-per-MMBtu per quadrillion Btu) by the heat rate derived above in the E-G cross-DRIPE section (which is measured in MMBtu per MWh). However, for this DRIPE category, we multiply this heat rate by the price shift twice. This translation yields price shifts in dollar-per-MWh per MWh (rather than dollar-per-MWh per MMBtu, as with G-E cross-DRIPE).

As with G-E cross-DRIPE, these price shifts are then multiplied by each state's unhedged energy to estimate total DRIPE benefits. For each state, the "energy" is the quantity of electricity demand (in MWh) in the state in question, consumed during the relevant period (e.g., winter, electric), under a particular counterfactual. This total quantity of energy is scaled by the portion of energy that is assumed to be unhedged in each state (i.e., the portion of energy purchases not expected to be subject to the spot market). As with G-E cross-DRIPE, this unhedged assumption is the same used in energy DRIPE, described above in Table 83.

Table 100 summarizes the E-G-E values for the annual period: these are the values that appear in the *AESC 2021 User Interface* and are applied by program administrators using Appendix B. Table 98 summarizes the summer and winter effects for historical comparison with AESC 2018. These values are not used in cost-effectiveness testing (except to the degree that the seasonal price shifts inform the annual price shift).

Table 100. Annual electric-to-gas-to-electric cross-fuel heating DRIPE, 2021 gas efficiency installations (2021 $ per MWh)

		Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
		NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
Annual	2021	9.32	1.55	4.68	1.11	1.04	0.73	0.21	7.77	4.63	8.21	8.27	8.59	9.11
	2022	14.05	2.34	6.99	1.69	1.60	1.12	0.31	11.71	7.06	12.36	12.44	12.93	13.74
	2023	16.19	2.81	7.67	2.05	1.94	1.35	0.37	13.37	8.52	14.14	14.25	14.83	15.82
	2024	13.07	2.25	5.97	1.78	1.73	1.01	0.32	10.82	7.10	11.29	11.33	12.06	12.74
	2025	10.77	1.56	4.98	1.54	1.55	0.86	0.28	9.21	5.80	9.23	9.22	9.92	10.49
	2026	7.45	1.12	3.31	1.10	1.10	0.61	0.20	6.32	4.14	6.34	6.35	6.84	7.25
	2027	4.68	0.77	2.06	0.68	0.68	0.38	0.12	3.92	2.63	4.00	4.00	4.31	4.56
	2028	3.34	0.57	1.46	0.48	0.48	0.27	0.08	2.77	1.88	2.86	2.86	3.07	3.26
	2029	2.06	0.36	0.90	0.30	0.29	0.17	0.05	1.71	1.16	1.77	1.77	1.90	2.01
	2030	0.96	0.19	0.41	0.14	0.13	0.08	0.02	0.78	0.55	0.83	0.83	0.89	0.94
	2031	0.13	0.03	0.05	0.02	0.02	0.01	0.00	0.10	0.08	0.12	0.12	0.12	0.13
	2032	0.00	0.00	0.00	0.00	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	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	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	0.00	0.00	0.00	0.00

Table 101. Seasonal electric-to-gas-to-electric cross-fuel heating DRIPE, 2021 gas efficiency installations (2021 $ per MWh)

		Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
		NE	CT	MA	ME	NH	RI	VT	CT	MA	ME	NH	RI	VT
Electric Summer	2021	1.96	0.33	0.99	0.22	0.21	0.16	0.04	1.63	0.97	1.74	1.74	1.80	1.92
	2022	2.95	0.50	1.48	0.33	0.33	0.25	0.06	2.45	1.47	2.62	2.62	2.70	2.89
	2023	3.40	0.60	1.62	0.41	0.40	0.30	0.07	2.80	1.78	3.00	3.01	3.10	3.33
	2024	2.74	0.48	1.27	0.35	0.36	0.22	0.06	2.26	1.48	2.39	2.39	2.52	2.68
	2025	2.26	0.34	1.06	0.31	0.32	0.19	0.06	1.93	1.21	1.96	1.95	2.07	2.21
	2026	1.57	0.24	0.71	0.22	0.23	0.14	0.04	1.33	0.87	1.35	1.35	1.44	1.53
	2027	1.00	0.17	0.44	0.14	0.14	0.09	0.02	0.83	0.56	0.86	0.86	0.92	0.98
	2028	0.72	0.13	0.32	0.10	0.10	0.06	0.02	0.60	0.40	0.62	0.62	0.66	0.71
	2029	0.46	0.08	0.20	0.06	0.06	0.04	0.01	0.38	0.25	0.39	0.39	0.42	0.45
	2030	0.22	0.04	0.10	0.03	0.03	0.02	0.00	0.18	0.13	0.19	0.19	0.21	0.22
	2031	0.05	0.01	0.02	0.01	0.01	0.00	0.00	0.04	0.03	0.04	0.04	0.04	0.05
	2032	0.00	0.00	0.00	0.00	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	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	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	0.00	0.00	0.00	0.00
Electric Winter	2021	10.09	1.66	5.05	1.24	1.15	0.76	0.23	8.43	5.04	8.85	8.94	9.33	9.86
	2022	15.21	2.50	7.54	1.89	1.76	1.17	0.35	12.71	7.68	13.32	13.45	14.04	14.87
	2023	17.53	3.02	8.27	2.29	2.13	1.42	0.41	14.51	9.26	15.24	15.40	16.11	17.12
	2024	14.16	2.41	6.44	1.99	1.91	1.06	0.36	11.75	7.72	12.17	12.25	13.10	13.80
	2025	11.66	1.67	5.36	1.72	1.70	0.89	0.32	9.99	6.31	9.94	9.97	10.77	11.35
	2026	8.04	1.20	3.55	1.23	1.21	0.64	0.22	6.84	4.49	6.81	6.84	7.40	7.82
	2027	5.02	0.81	2.19	0.76	0.74	0.39	0.13	4.21	2.83	4.27	4.28	4.63	4.89
	2028	3.55	0.60	1.54	0.53	0.52	0.28	0.09	2.95	2.01	3.02	3.04	3.28	3.46
	2029	2.17	0.37	0.94	0.32	0.31	0.17	0.05	1.80	1.23	1.85	1.86	2.00	2.11
	2030	0.97	0.19	0.41	0.14	0.14	0.07	0.02	0.79	0.56	0.83	0.84	0.90	0.95
	2031	0.09	0.02	0.03	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
	2032	0.00	0.00	0.00	0.00	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	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	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	0.00	0.00	0.00	0.00

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

This table indicates that the summer New England-wide value of G-E cross-DRIPE for 2021 is $1.96 per MMBtu. As with G-E cross-DRIPE, the winter value ($10.09 per MMBtu) is an order of magnitude larger because of the higher basis values in the winter months. For each state and year, the zone-on-Rest-of-Pool benefit equals the difference between the ISO-wide benefit and the zonal benefit. Table 102 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2018 and AESC 2021. As with other DRIPE categories relying on the price shift of natural gas supply, avoided costs for this category are lower in AESC 2021, compared to AESC 2018. This is primarily due to the reduced natural gas supply price shift, but it is also due to differences in projected loads and gas bases price shifts.

Table 102. Comparison of 10-year levelized electric-to-gas-to-electric (E-G-E) cross-DRIPE benefits (2021 $ per MWh)

	ISO NE	CT	MA	ME	NH	RI	VT
Electric Annual							
AESC 2018	-	-	-	-	-	-	-
AESC 2021	8.29	1.37	3.89	1.10	1.07	0.66	0.20
Difference ($)	-	-	-	-	-	-	-
Difference (%)	-	-	-	-	-	-	-
Electric Summer							
AESC 2018	7.10	1.55	3.48	0.68	0.72	0.53	0.14
AESC 2021	1.75	0.29	0.83	0.22	0.22	0.15	0.04
Difference ($)	-5.35	-1.25	-2.65	-0.46	-0.50	-0.38	-0.10
Difference (%)	-75%	-81%	-76%	-68%	-69%	-72%	-71%
Electric Winter							
AESC 2018	16.50	3.52	8.03	1.66	1.72	1.20	0.34
AESC 2021	8.95	1.46	4.18	1.22	1.17	0.69	0.22
Difference ($)	-7.55	-2.05	-3.85	-0.44	-0.56	-0.51	-0.12
Difference (%)	-46%	-58%	-48%	-26%	-32%	-42%	-35%

Note: Annual values were not provided in AESC 2018.

9.6. 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.

Oil's global dimension makes modeling oil DRIPE more uncertain than the analysis of natural gas DRIPE. The analysis in Chapter 3: *Fuel Oil and Other Fuel Costs* relies 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. For AESC 2021, we conduct a relatively high-level model of oil DRIPE in the following steps:

1) Estimate the relevant elasticity (i.e., the percentage change in oil price per percentage change in demand for crude oil).

2) Calculate the crude oil DRIPE value.

3) Calculate refined product DRIPE values using the ratios of crude-to-refined-product price from EIA's AEO 2021 for years 2021–2035.

Estimating elasticities

Elasticity describes how prices of a commodity respond to changes in demand. We use oil play breakeven analysis to estimate elasticity for crude oil.

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 can be made to show the prices at which various sources of new supply would enter the market. This curve can be thought of as analogous to an electric market's power plant offer stack.

By examining a set of these supply curves, we can assess the average relationship between price and supply for a marginal barrel of oil. Table 103 presents elasticities from five different breakeven analyses. Two of these curves display a supply curve with a very steep right tail. 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 per barrel. In other words, it indicates that a 1.0 percent increase in cumulative oil production in this region would increase costs by 0.36 percent.

Table 103. Percent change in crude oil price for a 1.0 percent change in global demand

Forecast	Curve Segment	Date Published	Elasticity	Sources
Wood Mackenzie	Entire curve	2016	0.36	(A)
Rystad Energy	Entire curve	2015	1.39	(B)
IEA	Entire curve	2013	2.00	(C)
Goldman Sachs	Low only	2012	0.47	(D)
Goldman Sachs	High only	2012	2.66	(D)
BP/PIRA	Low only	2015	0.88	(E)
BP/PIRA	High only	2015	3.60	(E)
Average (All)			**1.62**	
Average (Low Only + Entire Curve)			**1.02**	

Sources: (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/business-sites/en/global/corporate/pdfs/news-and-insights/speeches/new-economics-of-oil-spencer-dale.pdf.

A simple average of all elasticities yields a value of 1.62. If the two "High only" slopes are removed, the resulting average elasticity is 1.02. Given the uncertain nature of this analysis, AESC 2021 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.[265] Critically, demand in this context is *global demand* (currently 98 million barrels/day, of which the United States consumes about one-fifth).[266]

[265] 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.

[266] For more information, see https://www.iea.org/oilmarketreport/omrpublic/.

This estimate is similar to our estimate of elasticity of supply for natural gas. This is expected given the similarities between the two hydrocarbons, their disposition, and their extraction.

Next, we convert this elasticity into a "price shift" which represents how the price (in dollars per MMBtu) that changes in response to changes in demand (measured in quadrillion Btu per year). To do this, we multiply the elasticity by a forecast for West Texas Intermediate (WTI) crude oil prices ($8 to $14 per MMBtu, depending on the year) and divide the result by a forecast of crude oil consumption (estimated to be about 220 quadrillion Btu worldwide).[267] This yields a price shift of about $0.05 /MMBtu per quadrillion Btus for any given year.

Calculating oil DRIPE

As with the electric and natural gas DRIPE effects, the price reduction per MMBtu of oil saved is very tiny compared to the price per MMBtu. But each MMBtu saved reduced prices for a very large number of MMBtus. That said, 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.[268]

According to the latest EIA SEDS database, in 2014 through 2018, New England consumed approximately 1.4 quadrillion Btu of petroleum products yearly.[269] Over time, AEO 2021 forecasts demand gradually falling, averaging about 1.2 quadrillion Btu of petroleum products yearly between 2021 and 2035.

As a result, a 1 MMBtu reduction in crude oil demand yields an average regional benefit of about $0.07 per MMBtu (i.e., $0.05/MMBtu per quadrillion Btu multiplied by 1.2 quadrillion Btu). The value for each state, presented in Table 104, are proportionally smaller, ranging from about $0.003 per MMBtu to $0.030 per MMBtu per 1 MMBtu reduction.[270] Zone-on-zone values are calculated based on each state's share of oil consumption relative to the New England-wide total. Meanwhile, zone-on-region values are equal to the New England total minus the value from each respective state.

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[267] Crude oil prices are based on WTI prices from AEO 2021 and worldwide crude oil consumption is based on values in EIA's 2019 edition of the International Energy Outlook.

EIA. Last accessed March 11, 2021. "Petroleum and Other Liquids Prices." *Eia.org.* Available at https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

EIA. 2019. "Liquids Consumption: OECD: OECD Americas." *Eia.gov*. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=5-IEO2019&sourcekey=0.

[268] Calculated based on data from 2014 to 2018 using data from EIA. 2019. "State Energy Data System: Updates by Energy Source." *Eia.gov.* Available at https://www.eia.gov/state/seds/seds-data-fuel.php?sid=US#DataFiles

[269] See https://www.eia.gov/state/seds/seds-data-fuel.php?sid=US#DataFiles for more information.

[270] 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 per MMBtu.

Table 104. Crude oil DRIPE by state (2021 $ per MMBtu)

	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	NE	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.049	0.011	0.020	0.006	0.005	0.003	0.003	0.038	0.028	0.042	0.043	0.046	0.046
2022	0.052	0.012	0.022	0.007	0.006	0.003	0.003	0.041	0.031	0.045	0.047	0.049	0.049
2023	0.058	0.013	0.024	0.008	0.006	0.003	0.003	0.045	0.034	0.050	0.051	0.054	0.054
2024	0.061	0.014	0.025	0.008	0.007	0.004	0.003	0.047	0.035	0.053	0.054	0.057	0.057
2025	0.063	0.014	0.026	0.008	0.007	0.004	0.004	0.049	0.037	0.055	0.056	0.060	0.060
2026	0.065	0.015	0.027	0.009	0.007	0.004	0.004	0.050	0.038	0.056	0.058	0.061	0.061
2027	0.066	0.015	0.028	0.009	0.007	0.004	0.004	0.052	0.039	0.058	0.059	0.063	0.063
2028	0.068	0.015	0.028	0.009	0.008	0.004	0.004	0.053	0.040	0.059	0.061	0.064	0.064
2029	0.069	0.016	0.029	0.009	0.008	0.004	0.004	0.054	0.040	0.060	0.061	0.065	0.065
2030	0.071	0.016	0.029	0.009	0.008	0.004	0.004	0.055	0.041	0.061	0.063	0.066	0.067
2031	0.071	0.016	0.030	0.009	0.008	0.004	0.004	0.055	0.042	0.062	0.063	0.067	0.067
2032	0.072	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.064	0.068	0.068
2033	0.072	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.064	0.068	0.068
2034	0.073	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.065	0.068	0.069
2035	0.073	0.016	0.030	0.010	0.008	0.004	0.004	0.056	0.042	0.063	0.065	0.068	0.069
10-year levelized	**0.062**	**0.014**	**0.026**	**0.008**	**0.007**	**0.004**	**0.004**	**0.048**	**0.036**	**0.054**	**0.055**	**0.058**	**0.059**

Note: Values differ across states because states vary in terms of size of oil consumption.

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 regionwide demand reduction in 2021 is worth $0.049 per MMBtu and a reduction in 2025 is worth $0.063 per MMBtu). Oil DRIPE benefits are low because of the relatively modest amounts of demand in New England states compared to the size of the global oil market.

In order to apply oil DRIPE values to specific commodities (e.g., gasoline, home heating fuel), we multiply the values in Table 104 by the refined-price to crude-price ratio found in Table 105. For example, the levelized value of gasoline DRIPE across New England is worth $0.108 per MMBtu reduced ($0.062 per MMBtu x 1.73).

Table 105. AEO 2021 prices of crude oil and refined petroleum products

Product	2021-2035 Avg Price (2021 $ per gallon)	Ratio of product price to WTI price
WTI Crude Oil	1.59	-
Home heating oil	2.77	1.75
Residual fuel oil	1.63	1.03
Motor gasoline	2.75	1.73
Motor diesel	3.21	2.03

Source: EIA AEO 2021 Table: "Petroleum and Other Liquids Prices." Available at. https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

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 oil (for example). This simplifying assumption is reasonable given the small magnitude of oil DRIPE effects and the high-level analysis undertaken.

Table 106 illustrates the differences between crude oil DRIPE calculated in AESC 2018 and AESC 2021. In AESC 2021, oil DRIPE values for New England as a whole are 27 percent lower than in the previous study. This change is primarily due to reductions in forecasts of crude oil prices and crude oil consumption.

Table 106. Comparison of oil DRIPE values (2021 dollars per MMBtu)

	New England	CT	MA	ME	NH	RI	VT
AESC 2018	0.085	0.022	0.032	0.011	0.011	0.011	0.007
AESC 2021	0.062	0.014	0.026	0.008	0.007	0.004	0.004
Difference ($)	-0.023	-0.008	-0.007	-0.003	-0.004	-0.008	-0.003
Difference (%)	-27%	-38%	-20%	-27%	-39%	-67%	-48%

Note: Values shown are levelized over 10 years. AESC 2018 uses a discount rate of 1.34 percent while AESC 2021 values use a discount rate of 0.81 percent.

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 T&D facilities, due to reduced load growth and reduced loading of existing equipment.[271] The chapter describes a methodological approach that program administrators can use to estimate avoidable T&D costs for planning and reporting of efficiency program benefits.

In AESC 2018, we developed a general framework for the calculation of avoided T&D values, including identifying general principles for such calculations. AESC 2018 also surveyed some of the sponsoring utilities (National Grid, United Illuminating, and Eversource Connecticut) for information on utility avoided T&D value estimates, along with the methods used to calculate those values. AESC 2018 separated PTF transmission for a separate treatment and developed an estimate of the value of avoided PTF transmission of $94 per kW-year in 2018 dollars ($99 per kW-year in 2021 dollars).

For AESC 2021, we present four separate threads for analysis of avoided T&D costs, building on the foundation established in the 2018 AESC and updating or expanding the analysis presented. The four aspects are:

1. Updating the avoided costs for PTF facilities using a forward-looking projection, rather than a historical estimate. The updated analysis finds an updated PTF value of $87 per kW-year in 2021 dollars.
2. Reviewing utility approaches to generic avoided cost values for non-PTF T&D and evaluating these approaches on a common evaluation rubric to facilitate cross-comparison and learning.
3. Reviewing utility approaches to calculating geographically localized avoided costs, such as for NWAs.
4. Developing an approach to the avoided cost of natural gas system T&D. See Section 2.4: *Avoided natural gas cost methodology* for more information on the assumptions used in AESC with respect to natural gas T&D.

In addition to evaluating different approaches to geographically localized avoided costs for NWAs as a standalone aspect of analysis, AESC 2021 examines across each aspect whether the appropriate treatment or calculation of T&D avoided costs differs for other specific technology types or program applications, such as distributed generation and electrification or other fuel switching programs. AESC

[271] 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.

2021 address the locational value of potential services provided by efficiency and other DERs; we do not address programmatic or other barriers to using DERs to address T&D costs.

This section begins with an overview of the recommended approach for calculating avoided T&D costs, which can then be tailored to the specific situation for which costs are to be calculated. We then proceed through the different aspects and scales of such analysis in New England, beginning with region-wide PTF. The subsequent two sections address avoided T&D at smaller scales: first for a utility service territory or other program-wide jurisdiction, and then for specific locations on areas within a service territory which may warrant location-specific avoided T&D values due to an existing constraint. For each of these scales, we present an evaluation of the relevant methods currently used by utilities within the region. The section concludes with an analysis of the equivalent structure for natural gas distribution (see Section 2.4: *Avoided natural gas cost methodology* for more information).

10.1. General approach to estimating the value of system-level avoided T&D

The following steps, unchanged from AESC 2018, summarize a standardized approach to estimate generic system-level 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.[272]
- 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 $ per MW or $ per 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 $ per kW-year.
- Step 6: Add an allowance for operation and maintenance of the equipment to derive the total avoidable cost in $ per kW-year.

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 NWAs to specific T&D projects. Analysis of targeted NWAs requires information

[272] 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.

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 methodology for localized value of avoided T&D is the subject of Section 10.4 below.

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).[273] Under 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 defer or 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 past projects used in the analysis were not usually avoided, and near-term future projects may also not be 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 defer or avoid the addition of a line transformer in the next year. It may also 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 dynamic, the general 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.[274]

The methods and approach described here are generally independent of the technology or program that changes peak load. For example, the value of avoiding transmission investments does not depend on whether the peak was reduced by energy efficiency, demand response, or distributed generation—as long as the peak reductions are the same. It is also critical that the peaks in question are the same peaks: if transmission needs are driven by a summer system-wide peak, or distribution needs are driven by a winter morning, then the characteristics of a given measure or program at those times are what matter for avoiding expenditures. The marginal benefit of reduced peak should also be the same as the marginal cost of increased peak: electrification measures that increase a peak that is relevant for T&D

[273] 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.

[274] Geographically targeted load reductions, such as part of an NWA to a transmission or distribution project, may have much higher values, depending on the magnitude and time of need, as discussed in more detail in Section 10.4.

infrastructure planning will, on the margin, create costs at the same rate (in $/kW) that load reduction measures reduce them. Note that time coincidence matters for electrification as well as energy efficiency: electrification measures that increase a winter peak do not cause T&D expenditures if those expenditures would be driven by the need to meet loads at a summer peak.

The remainder of this section provides an overview of background, context, and considerations to be kept in mind and used as guidance in developing avoided T&D values. The following two subsections apply these lessons and guidance to PTF transmission (Section 10.2) and to evaluation of the methods used for generic avoided T&D in the region today (Section 10.3).

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, any analysis should use data from complete, consistent, and reasonable time periods for both load and investment. It may be useful to align these timelines with those used for distribution planning and capital investment planning processes.
- **Investment plans and budgets for any future period must be reasonably complete.** It is important to capture all of the expected T&D costs along with all of the expected changes in load within the period selected for analysis. Investment plans that include only a portion of projected costs (for example, those associated with only larger projects with long lead times) should not be the only source of cost information.
- **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, adjusting the loads to account for the weather conditions is likely to be more representative than actual loads in determining the amount of load growth in the analysis period, so weather adjustment may be necessary. Taking actual load growth between a hot summer with high loads and a subsequent 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 same growing areas. 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 differing years (e.g., 1997, 2007, 2017, and 2027) 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 hypothetical worlds in which no energy efficiency programs (and/or no other load management or electrification 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.[275]

If a fully consistent no-energy efficiency (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:

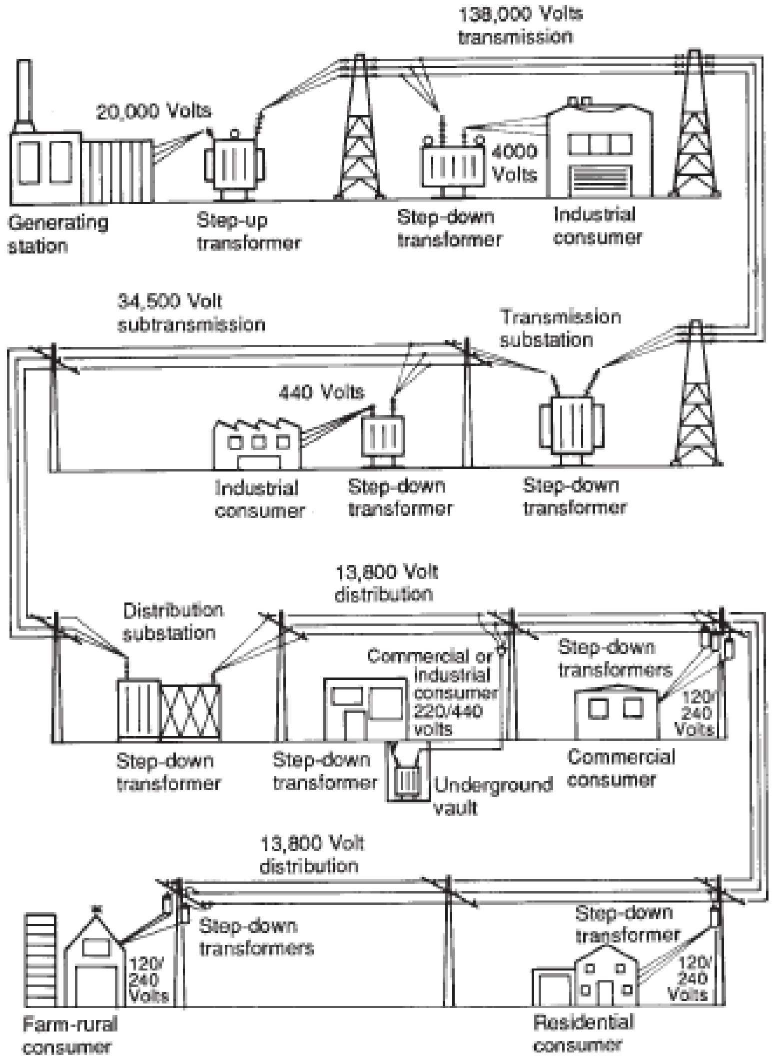
- high-voltage transmission lines (115 kV to 345 kV);
- transmission substations connecting transmission lines at different voltages;
- subtransmission lines (e.g., 69 kV) that connect to distribution substations and some very large customers;
- bulk distribution substations that step transmission voltages down to generally high distribution voltages (mostly at 13.8 kV to 25 kV);

[275] 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.

- 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 51 illustrates the general design of T&D systems. The range of voltages considered to be subtransmission varies among utility systems.

Figure 51. Schematic of a T&D system



Source: Electric Power Generation, Transmission and Distribution eTool. United States Department of Labor. Available at https://www.osha.gov/SLTC/etools/electric_power/illustrated_glossary/.

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 use the peak loads applicable to the transmission or distribution capacity appropriate to the particular 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 been associated with an hour ending at 3 p.m. or 5 p.m. 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.[276] If screening assumptions cannot be developed for extreme conditions, analysts should avoid the use of extreme loads in the avoided-cost analyses. Note that this may mean using different weather for the purposes of demand-side measure evaluation than is used for T&D system planning, and tracking different "flavors" of peak load or developing equivalency relationships may be required.

Similarly, if screening uses load reduction at the end-use, the avoided T&D costs should use load growth at the end-use. If this apples-to-apples structure is not possible (such as if load growth is measured at transmission level) the appropriate 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 2021 recommends using top-down accounting analyses to identify the accounts that are primarily load-related,[277] and net

[276] Something must use more energy at the extreme peak, or it would not be an extreme peak.

[277] As the availability and granularity of data improves through technologies and planning advancements, we anticipate improvements in the methodology for identification of load-related investments that can be avoided through DERs and applicability to more feeders. The methodology described in AESC 2021 is based on identifying load-related investments using current distribution system planning practices.

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.[278]

For the bottom-up analyses, AESC 2021 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.[279]
- 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.[280]
- Some T&D investments simply replace old equipment. Other investments relocate facilities due to road widening, loss of easements, and similar factors. Neither type of investmetns 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.

[278] 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.

[279] 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.

[280] 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.

A third set of investments is harder to characterize, including such situations as:

- Investments triggered by factors other than load, but whose cost are 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 future, the incremental cost of the taller poles is load-related. The cost of replacement may be unavoidable, but the load-related improvement may be avoidable.[281]

- 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.[282]

AESC 2021 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

[281] In principle, the decision not to downsize the replacement may also be load-related, but the incremental component of project cost may be difficult to quantify.

[282] 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 the distribution level, or at the meter.[283] 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 $ per kW at the meter and lowest as $ per 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, rather than using end-use load, losses from the meter to transmission must be added back to get the avoided cost in $/kW of load at the meter.[284]

Investments in T&D infrastructure to support load growth generally do not increase the capacity of the relevant portions of T&D system by only the exact amount of projected load growth. Instead, it is typical to use standard equipment (which may be larger than strictly necessary) or to design in an allowance for future growth over the multi-decade useful life of a piece of infrastructure. For example, the aggregate capacity of all of a utility's distribution infrastructure often far exceeds the sum of substation peak loads. When matching the load growth to the investment, it is therefore necessary to determine whether the relevant capacity is the increase in peak load, or the increase in capacity of the relevant portion of the T&D system.

The only choice that is consistent with an avoided cost formulation for demand-side measures is to use the actual growth in peak load, rather than the capacity of the new hardware. This is because the load avoided by a demand-side measure is the actual peak load. If the avoided T&D value were calculated by

[283] 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).

[284] 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.

dividing the infrastructure cost by its additional peak capacity (that is, if the value were in units of $ per $kW_{hardware}$) then when multiplying this value by the peak reduction produced by an energy efficiency program ($kW_{end-use}$) the calculation would understate the value of efficiency by a ratio of $kW_{hardware}$ per $kW_{end-use}$. In addition, the extent of overcapacity built into hardware once the decision is made to construct is entirely independent of the incremental peak capacity that caused the decision.

For example, take a load-growth-related investment with an annual carrying cost of $100,000 that is caused by an increase in load of 100 kW, but increases the capacity of the relevant portion of the grid by 1 MW. If the avoided cost value were based on the hardware installed, it would be $100 per $kW_{hardware}$-year, while if it is based on the load, it would be $1,000 per $kW_{end-use}$-year. If load were actually reduced by 100 kW through a demand-side intervention, these two avoided cost calculations would imply different values of the avoided cost: $100,000 per year in the end-use case and only $10,000 per year in the hardware case. Since we know that the $100,000 per year investment would have been avoided by the 100 kW load reduction, only the load-derived calculation can be correct.

While in theory a generic ratio of $kW_{end-use}$ to $kW_{hardware}$ could be used to adjust for this effect, when combining many such decisions across time and across a service territory, consistency and coherence in the meaning and scale of $kW_{hardware}$ would almost certainly be lost. Therefore, the calculation of avoided T&D costs should use the actual kW of load, rather than the kW of new hardware capacity.

Dealing with absence of system load growth

As noted previously, 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, utilities 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, a 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.[285] The AESC Reference (Scenario 1) case assumes a world with no new energy efficiency, no active demand management, and no building electrification programs, in which the avoided costs computed for the areas with growth would be applicable to the entire utility.

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.

[285] We are unaware of any utilities that have estimated what capital expenditures would have been without historical DSM effects or what capital expenditures would be in the absence of future DSM effects.

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 it 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.[286] 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.

[286] "Gross plant" is defined as the total capital assets dedicated to utility service and is used to determine rate base.

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. Avoided pool transmission facilities transmission

All load in New England pays for PTFs, in addition to local facilities in the local networks. AESC 2018 used ISO New England's then-current Transmission Cost Allocation (TCA) data to identify $6.7 billion (in 2018 dollars) in load-related investments in substations, new lines, voltage upgrades, and additional capacitors and transformers for projects completed or planned for 2003 through 2020, plus two small projects planned for 2021 and 2024. Using the most expansive interpretation of the actual and projected load growth that would have justified those investments, AESC 2018 estimated the avoided PTF cost as $94 per kW-year in 2018 dollars (equal to $99 per kW-year in 2021 dollars).

After the completion of AESC 2018, several stakeholders raised a concern that the analysis was backward-looking rather than prospective. To address this concern, we reviewed the projects in the October 2020 Draft Regional System Plan (RSP) Project List, which includes descriptions and estimated costs for projects under construction, planned or proposed through 2023, plus two small projects planned for 2024 and 2026.[287] This listing may contain some projects that will never be approved, but it probably does not include all the projects that will be scheduled through 2023, let alone 2026. The October 2020 RSP Project List update added several projects proposed for service as early as December 2021, so more projects are likely to eventually be proposed for 2023–2026.[288]

We do not have data on the amount of past and projected load growth driving these transmission expansion plans. The overall ISO New England peak loads are declining, due in part to the energy efficiency programs. However, loads in some areas have been growing and are expected to continue growing, justifying addition of the RSP load-related projects.

Lacking detailed data on the recent projected load growth for which the RSP projects are proposed, we examined whether the proposed annual rate of PTF additions is comparable to the annual rate of PTF additions in the historical data used in the 2018 AESC analysis. Specifically, we computed the apparently load-related expenditures by year for the historical data and the projected RSP costs. For the future-looking RSP costs, we excluded any projects listed as under construction in the ISO England October 2020 project list to make the computation entirely forward-looking.

[287] ISO New England. October 2020. *ISO-New England Project Listing Update*. Available at https://www.iso-ne.com/static-assets/documents/2020/10/final_project_list_october_2020.xlsx.

[288] Several other projects planned for completion in the early 2020s in the October RSP Project List were first proposed in 2018 through early 2020. Costs of projects currently proposed, planned, or under construction may rise by the time the projects are completed.

Table 107. Comparison of annual load-related additions, historical and projected (2021 dollars)

Historical Project Costs (based on TCA)			Future Project Costs (based on RSP)		
period	*$M*	*$M/year*	*period*	*$M*	*$M/year*
2003-2020	$7,008	$389	2021-2023	$991	$330
2003-2024	$7,050	$321	2021-2026	$1,074	$179

The historical TCA data appear to be quite comprehensive through 2018 (the last year containing actual cost data) and even through 2020, and then became sparse. Similarly, the RSP data appear to be complete through 2023 (with 37 reliability projects) and thin thereafter (with only one project scheduled for 2024 and another for 2026). Between June and October 2020, 13 load-related projects totaling $126 million were added to the RSP with in-service dates of 2021 to 2023, in addition to the two later projects, with an estimated cost of $84 million.[289] It is likely that additional projects will be added for in-service dates after 2023. Excluding the thin and incomplete tails (post-2020 for the historical costs and post 2023 for the projected costs), projected future annual investments are equal to 85 percent of the historical investment-per-year rate ($330 million per year, compared to $389 million per year in as estimated in AESC 2018).

We assume that the forecasted localized load growth underlying the future RSP budgets is comparable to the historical load growth driving the historical TCA projects. As a result, we calculate an avoided PTF cost for future years by multiplying the value derived in AESC 2018 by 89 percent. This yields a value of $84 per kW-year in 2021 dollars. Regional transmission needs are driven, and have been driven, by summer peak loads. Therefore, the regional PTF value should be applied to evaluation of measures that change the summer peak.

10.3. Survey of utility avoided costs for non-PTF transmission and distribution

AESC 2021 includes a new rubric to evaluate and compare the methodologies for non-PTF avoided T&D used by utilities in the Study Group. AESC 2018 included a discussion of methods used by several utilities (National Grid, United Illuminating, and Eversource Connecticut). AESC 2021 builds on that structure by formalizing this rubric. This rubric is based on the parameters and areas detailed in Section 10.1 above. The key areas of evaluation rubric include:

1. Load (whether past, forecast, or a combination);
2. Identifying which expenditures are avoidable or deferable by changes in load (e.g., are "load-growth-related");
3. Matching the changes in load to the load-growth-related investments (e.g., in time);

[289] Dollar years are not indicated in the RSP document. Because some spending may be underway today, because there may be a mix in reporting dollar years in terms of current real dollars and future-year nominal dollars, and because the inflation over the 2021–2026 is minimal, we assume that all spending is in 2021 dollars for purposes of simplification.

4. Mapping lumpy investments to an annual value; and
5. Inclusion of other costs associated with T&D investments, such as O&M and overhead.

Evaluation of current utility methods

The following describes our review of data provided by participating utilities that informs the T&D avoided cost quantification approach. Below, we present summary tables of the evaluation rubric, applied to each utility that responded to the request for information about their current avoided T&D cost calculation methodologies. Table 108 summarizes the avoided T&D values currently in use. Table 109 provides a summary of the load forecast methodologies used in developing these avoided T&D cost values. Table 110 provides more detailed methodological considerations used in deriving the avoided cost values.

Table 108. Summary of utility avoided T&D cost methodologies

Criterion	Eversource CT	Eversource MA	Eversource NH	National Grid MA	National Grid RI	UI CT	Vermont VT	Maine ME	Unitil MA
In evaluating or screening DSM, does utility have a method for valuation of avoided distribution costs	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
The existing value of avoided distribution costs used by utility in evaluating and screening DSM	$14.05/kW (2018$)	$198/kW (2018$)	$79.98/kW (2018$)	$102.48/kW (2019$)	$80.24/kW (2019$)	$30.29/kW (2017$)	$0/kW-Yr	Mid Value: $246.79 (nominal)	$222.56 (2018$)
The year in which avoided distribution cost was developed	2018	2018	2017	2019	2019	2017	2018	2020	No data available
Frequency at which avoided distribution cost is updated by utility	No regular frequency	Every 3 years	No regular frequency	Every 3 years	With AESC Update	No regular frequency	No regular frequency	No regular frequency	No data available
In evaluating or screening DSM, does utility have a method for valuation of avoided transmission costs	Yes (PTF and Non-PTF)	Yes (PTF only)	Yes (PTF only)	Yes (PTF only)	Yes (PTF only)	Yes	Yes (PTF only)	Yes	Yes
The existing value of avoided transmission costs currently used in evaluating and screening DSM	Applies $1.03 $/kW-Yr in addition to $94/kW-yr	$94/kW-yr	$94/kW-yr	$94/kW-yr	$94/kW-yr	$0.84/kW-yr	$94/kW-yr (Efficiency VT); $45/kW-yr (BED)	Mid Value: $56.88/kW-yr + PTF ($94/kW-yr)	$94/kW-yr
The year in which avoided transmission costs were developed	2018	2018	2018	2018	2018	2017	2018 (Efficiency VT); 2012 (BED)	2020	2018
Frequency at which avoided transmission costs are updated	No Regular Frequency	With AESC Update	With AESC Update	With AESC update	With AESC update	No Regular Frequency	With AESC update (Efficiency VT) No Regular Frequency (BED)	PTF portion with AESC update	With AESC Update

Notes: Methodology for Maine represents EMT's proposed approach. For details on Unitil's approach, see D.P.U. 18-110 – D.P.U. 18-119 Three-Year Plan 2019-2021, October 31, 2018 Exhibit 1, Appendix C - Electric Page 36 of 43 https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-With-Appendices-no-bulk.pdf.

Table 109. Avoided T&D load forecast methodologies

Criterion	Eversource			National Grid		UI	Vermont	Maine
	CT	*MA*	*NH*	*MA*	*RI*	*CT*	*VT*	*ME*
Load forecast granularity used in calculating avoided costs at a utility-wide level	Transmission and Substation	Transmission and Substation	Transmission and Substation	Transmission and Supply area level	Transmission and Supply area level	Transmission Level	Transmission (Based on AESC)	Based on data available from CMP
Inclusion of the following in load forecasts:								
Operational EE	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Based on data available from CMP
Operational PV	Yes	Yes	Yes	Yes	Yes	Yes	Yes	
Operational DR	Yes	Yes	Yes	Yes	Yes	No	No	
Inclusion of the following in load forecasts:								
Projected EE	Yes	Yes	Yes	No	No	Yes	Yes	Based on data available from CMP
Projected PV	No	No	No	Yes	Yes	Yes	Yes	
Projected DR	Eversource sponsored programs only	Eversource sponsored programs only	Eversource sponsored programs only	Yes	Yes	No	No	
Inclusion of any electrification goals or mandates reflected in current policy	No	No	No	Yes	Yes	No	Yes	Based on data available from CMP
Existence of a process for identifying expenditures *avoidable* through load reductions	Yes	Yes	Yes	Yes	Yes	Yes	No	Based on data available from CMP
Existence of a process for identifying expenditures *deferrable* through load reductions	Yes	Yes	Yes	Yes	Yes	Yes	No	Based on data available from CMP

Notes: In Massachusetts and Rhode Island, National Grid excludes projected energy efficiency beyond the current plan in its forecast for determining the value of avoided distribution costs for DSM. It does account for continued lifetime savings from the current and prior plan years with a decay rate over time.

Table 110. Detailed considerations for calculation of load-specific avoided T&D costs

Criterion	Eversource			National Grid		UI	Vermont	Maine
	CT	*MA*	*NH*	*MA*	*RI*	*CT*	*VT*	*ME*
Existence of a process for deciding years of expenditure that factor into avoided transmission and distribution cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Based on data available from CMP
Use of the following when calculating avoided T&D costs (past values/future values/combination of past and future)	Combination	Combination	Combination	Combination	Combination	Combination	N/A - using AESC avoided PTF	Based on data available from CMP
Existence of a process for matching load levels to load-growth-related investments	No	No	No	No	No	No	N/A - using AESC avoided PTF	Range of values presented matching load levels to investments.
Whether utility applies a carrying cost to these investments to annualize investment values when calculating the avoided cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Yes
Whether utility applies avoided O&M costs associated with investments when calculating avoided cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Yes
Whether utility applies an avoided overhead cost associated with investments when calculating avoided cost	Yes	Yes	Yes	Yes	Yes	Yes	N/A - using AESC avoided PTF	Yes

The following sections present short descriptions of the methods used by each responding utility.

National Grid (Massachusetts and Rhode Island)

National Grid calculates its avoided distribution capacity values for both its Massachusetts and Rhode Island DSM programs using a workbook developed in 2005 by ICF International, Inc., updated with recommendations from the 2018 AESC Study. The company updates this workbook for each three-year planning cycle. The workbook calculates an annualized value of statewide avoided distribution capacity values from company-specific inputs that include historical and projected capital expenditures and peak loads, carrying charges, FERC Form 1 accounting data, and O&M costs.[290] National Grid uses a combination of historical and forecasted values within the workbook and accounts for operational energy efficiency, PV, and demand response programs. The load forecast used to determine the value of avoided distribution only includes projected PV and continued lifetime energy efficiency savings from prior plans and the current plan. The analysis does not include forecasted savings from future energy efficiency plans.

National Grid determines the percentage of the total distribution investments that are load-growth-related but not associated with new business. The resulting percentage is then applied to the distribution investment forecast. For avoided transmission costs, National Grid uses the 2018 AESC PTF of $94 per kW-year (in 2018 dollars) in both Massachusetts and Rhode Island. It does not account for non-PTF transmission costs.[291]

Table 111 summarizes the distribution methodology employed by National Grid, as well as recommendations for improvement.

[290] The Narragansett Electric Company d/b/a National Grid. Docket No. 5076 - 2021 Annual Plan. Attachment 4.

[291] The analysis in this section is based on National Grid MA and RI - 2018 Avoided T&D Workbooks,

Table 111. Assessment of National Grid's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology is mostly consistent with recommended methodologies in its consideration of load-growth-related T&D investments.	National Grid should account for non-PTF transmission costs.	-
Categories of investments considered	National Grid uses historical and forecasted T&D investments and assumes a percentage of that investment is related to load growth not associated with new business and is therefore avoidable with DSM.	It is not clear how the percentage of avoidable distribution investments were calculated since they are significantly lower than the overall distribution investments. It is unclear whether this estimate of the avoidable investments reflects all load-growth-related projects, including any capacity-related projects undertaken for non-load growth purposes such as reliability improvements.	National Grid should provide more transparency regarding the calculation of percentages representing load growth and new business. National Grid should use a more granular approach in the breakout of its T&D investments.
Load Forecast Methodologies	National Grid includes the impact of historical adoption of EE measures but does not include the impact of forecasted EE adoption.	National Grid should use a load forecast that includes future projected EE savings since the investment forecast assumes continued EE programs.	-
Detailed Considerations	National Grid uses a relatively short period of 11 years (5 years of historical data and 6 years of forecasted data) which may not be long enough to account for lumpiness associated with investments across the years. National Grid applies a carrying cost to investments when calculating avoided costs. National Grid includes both O&M and overhead costs in calculation of avoided costs.	National Grid should use a longer-term period for its analysis, in the range of 25-27 years. .	-

United Illuminating

United Illuminating developed estimates of the avoided T&D expenditures due to Conservation and Load Management (CLM) based on values from a 2017 Harbourfront Group study.[292] The 2017 Harbourfront study uses principles of marginal cost of service in order to develop a marginal cost of transmission based on coincident peak demand and a marginal cost of service based on non-coincident peak demand. The study calculated values for both historical years (2000–2016) and future years (2017–2026). The analysis assumed that non-coincident peak impacts resulted in substation and feeder demand reduction from all CLM measures, therefore resulting in the maximum estimate. The study also

[292] United Illuminating, Avoided Transmission and Distribution Cost Study 2000–2006.

assumed that the T&D costs that are avoided by the implementation of a CLM load reduction measure are the same as the marginal cost of T&D for adding or subtracting an increment of load. For the distribution system, the process involves identifying the T&D projects by separating out those that are load-growth-related from those that are not growth-related. For the transmission system, only projects that are undertaken to meet regional and national transmission and reliability standards were considered. The categories for the projects considered include transmission substation, transmission lines, distribution substations, and distribution feeders. The denominator for the marginal cost calculations is the added capacity or the load-serving capability of the capital project. The methodology used an economic carrying charge model and includes O&M expenses and overheads.

Table 112 summarizes the distribution methodology employed by United Illuminating, as well as recommendations for improvement.

Table 112. Assessment of UI's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology is broadly consistent with Avoided T&D methodologies in its consideration of load-growth-related T&D investments. The methodology is inconsistent with Avoided T&D methodologies in its consideration of load growth. The study is a marginal cost of service study more suited for application for purposes of cost allocation across different rate classes.	The study provides a marginal cost which uses a different methodology compared with the Avoided T&D cost methodologies suggested in this AESC. In the marginal cost development, the total investments identified for load growth projects were divided by the load-serving capability in developing the marginal costs. However, for an Avoided T&D study we recommend dividing instead by the growth in peak demand during the timeframe identified. The avoided costs were developed in context of the CLM program and its applicability to other programs should be evaluated and updated accordingly.	UI has used a weighting construct where 20% of their Avoided T&D value is combined with 80% of Eversource Avoided T&D value at the distribution level and transmission level. Further information would be beneficial regarding the accuracy and rationale of these assumptions.
Categories of investments considered	UI includes all growth- and capacity-related projects in calculation of avoided T&D costs. This includes capacity-related investments associated with projects that are undertaken for reliability improvements. UI considers both transmission and distribution investments at the substation and also considers feeder level distribution investments.	-	UI should clarify how it considers and includes investments that may be harder to characterize as solely load growth projects but may also contribute to alleviating load constraints.
Load Forecast Methodologies	In evaluating investments, UI includes the impact of historical adoption of CLM measures but does not include in forecasted CLM adoption. This methodology is accurate in	UI should include the impacts of electrification and state policy goals when identifying avoided T&D investments Although UI has developed a load forecast for identification of load	The load forecast methodology is not clear in terms of other energy efficiency measures included in the load forecast and the applicability of these values across other programs.

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
	quantifying the infrastructure costs that would be required without CLM provided that the investments and capital expenditure estimates also reflect growth without CLM included for consistency	growth related investments, for an Avoided T&D study we recommend dividing these investments by the growth in peak demand during the time frame identified as opposed to the load serving capacity of these projects identified.	
Detailed Considerations	Although there is no process for matching investments to load growth years, application of the relatively long period of 27 years (17 years of historical data and 10 years of forecasted data) accounts for some of the lumpiness associated with investments across the years. The analysis includes projects that could potentially be avoided or delayed by the implementation of CLM measures. UI has applied a carrying cost to investments when calculating avoided costs. UI has included both O&M and overhead costs in calculation of avoided costs.	-	-

Eversource (Connecticut, Massachusetts, and/or New Hampshire)

Eversource developed avoided or deferred T&D estimates using broadly similar methodologies across the three states it serves (Connecticut, Massachusetts, and New Hampshire) with some key differences in calculation of the percentage of avoidable or deferrable investments that could be considered in calculating the avoided costs. Its analysis in all three states considered both historical and forecasted investments on the T&D system.[293] For Massachusetts and New Hampshire, the methodology involved developing a value using the incremental investments and the incremental peak load growth over the same timeframe. In each of these states, Eversource assumed a certain percentage of the total T&D investments, respectively, were load-growth-related.

In the case of Connecticut, Eversource used a different approach. The methodology involved developing an additional regression analysis between historical investments and new customers to find the unavoidable investments associated with customer growth. These historical T&D investments that are related to customer growth are not considered avoidable/deferrable and are therefore removed from the analysis. Eversource used results of the regressions to evaluate the percentage of the T&D

[293] The analysis in this section is based on Eversource MA–2018 Avoided T&D Workbooks, Eversource CT–2018 Avoided T&D Workbooks and Eversource NH–2012 Avoided T&D Workbooks.

investments in Connecticut that are avoidable/deferrable, instead of the application of a percentage for Massachusetts and New Hampshire. Following this, Eversource conducted a regression analysis between incremental investments and peak load growth to assess the incremental investments associated with peak load growth in $/MW. The results of the two steps were combined to develop an annualized Avoided T&D cost.

Table 113 summarizes the distribution methodology employed by United Illuminating, as well as recommendations for improvement.

Table 113. Assessment of Eversource's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Overall T&D Methodologies	The methodology used by Eversource is broadly consistent with Avoided T&D methodologies in its consideration of load-growth-related T&D investments and load growth. In the case of NH, the recommendations outlined are based on review of the workbooks used in developing the 2012 values. Eversource indicated that the methodology in subsequent updates has remained consistent.	Eversource does not currently estimate avoided/deferred T values for MA and NH. Synapse recommends calculating these values and updating at a consistent frequency.	Certain assumptions outlined below have not been supported with underlying sources and calculations. These should be provided in future updates. For CT, both United Illuminating and Eversource have indicated the use of a 20/80 weighted average based on the respective customer base. Calculations outlining the weighting process should be provided to ensure consistency between both entities.
Categories of investments considered	Eversource does address the inclusion of growth- and capacity-related projects in calculation of avoided T&D costs, although it is unclear if these have been accurately estimated.	In the case of NH and MA methodologies, it is not clear how the percentage of avoidable/deferrable investments were calculated and whether they are fully capturing all the avoidable load-growth-related investments. In the case of CT, the non-avoidable or deferrable T&D investments were derived using a top-down approach based on the number of customers added to the system. Eversource should consider looking at specific projects on a case-by-case basis that could be avoided or deferrable through load reductions.	To increase transparency and ensure consistency with AESC methodologies in calculation of avoidable/deferrable investments, Eversource should identify underlying sources that specify the methodology and calculations applied in identifying the historical and forecasted capital investments. This should include sources that outline the following: 1. The categories of investments considered (e.g., substation/feeder) and the inclusion of investments in the analysis that are incurred to address local load growth. 2. The analysis conducted in classification of investments as avoidable or deferrable including any calculations made to derive the avoidable/deferrable percentage estimates for both MA and NH Avoided D estimates.

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Load Forecast Assumptions	As of 2018, Eversource had not included the impacts of electrification in its forecast of T&D capital expenditures for the purpose of calculating avoided/deferred T&D costs. However, Eversource has indicated that future load and capital expenditure forecasting will include the impact of electrification.	-	The CT regression methodology for statewide T&D uses a presumed rate of load growth based on historical growth using data from the CT Siting Council. However, it is not clear if the load growth assumed for identifying the capital investments (typically done through T&D planning process) used this same estimate of load growth. These should be consistent. For MA and NH, due to limited data availability underlying the development of the load forecasts and capital expenditures, further details are required to ensure consistency with methodologies outlined in AESC. Eversource has indicated that the load forecasts used for T&D investment planning are consistent with those used for Avoided T&D estimates.
Detailed Considerations	Although there is no process for matching investments to load growth years, application of the relatively long period of data accounts for some of the lumpiness associated with investments across the years. Eversource has applied a carrying cost to investments when calculating avoided/ deferred costs. Eversource has included both O&M and overhead costs in calculation of avoided/deferred costs.	-	-

Unitil (Massachusetts and/or New Hampshire)

No specific information was provided.

Vermont

For statewide energy efficiency programs administered through Efficiency Vermont, the state uses the 2018 AESC PTF of $94/kW-year as a proxy for both the statewide average avoided cost of distribution and transmission combined.

This is due to the fact that within Vermont loads are expected to remain on a flat-to-declining trajectory for the foreseeable future and there have been no geographic locations where targeted energy efficiency could defer needed T&D investments since 2012. In addition, Vermont is facing generation constraints where substations are at thermal loading capacity, as described in more detail in the section below. This means that energy efficiency could create additional costs instead of avoided costs.

Similarly, the City of Burlington Electric Department (BED) does not assume any avoided distribution costs because the system is overbuilt. BED uses a value of $45 per kW for avoided transmission costs that was originally developed and approved in 2012.

Table 114 summarizes the distribution methodology employed in Vermont, as well as recommendations for improvement.

Table 114. Assessment of Vermont's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
Overall T&D Methodologies	Vermont uses only the PTF value, for the combination of PTF and non-PTF transmission, and distribution. The PTF methodology is consistent with the recommendations of this chapter, by default. The Burlington value does not reflect the region-wide nature of avoided PTF. Vermont does not derive any value for avoided non-PTF transmission or for distribution.	Vermont should apply the same avoided PTF transmission costs across the state. Vermont should consider tracking winter distribution peaks to identify whether electrification could cause the need for distribution upgrades and whether CLM could mitigate those costs.	Vermont should explicitly analyze and document the use of a $0 value for avoided non-PTF transmission and distribution costs, taking into account in-state differences in loads, distributed generation, and the impact of potential electrification.
Categories of investments considered	Because Vermont does not have a state-specific methodology for avoided T&D costs, it does not consider which investments are load-growth-related or whether to conduct analysis at the substation or feeder level.	-	-
Load Forecast Methodologies	VELCO Long Range Transmission Plan (LRTP) includes load forecasts that account for EE, PV, DR, and adjusts for the amount of efficiency embedded in the actual data along with the amount of efficiency expected to occur in the future.	-	-
Detailed Considerations	None	-	-

Maine

Efficiency Maine Trust (EMT) engaged Synapse as a subcontractor to ERS to develop statewide avoided T&D costs in dollars per kilowatt-year ($/kW-year). The methodology used in developing the values is consistent with methodology outlined in AESC. The analysis was dependent on data provided by Central Maine Power (CMP). Based on this limited data availability, Synapse has assumed that the avoided T&D cost for CMP will serve as a proxy for the statewide avoided T&D cost.[294] The developed avoided T&D

[294] Synapse did not have access to Versant data. While Synapse assumes the value for Versant will be nonzero, Synapse has no further information at this time and thus cannot include it in the statewide estimate.

value is based on the overall long-term ratio of T&D savings per kW of avoided growth using peak load forecasts and planned capital additions based on CMP data.

In calculated the distribution expenditures, CMP uses forecasted load at the level of the service center as part of Chapter 330 filings.[295] Synapse used the 50/50 load forecast from these filings. CMP provided Synapse with data for load-growth-related distribution capital expenditures. Some of the distribution capital expenditures were classified as both transmission and distribution; and in those cases a portion of such projects were allocated to transmission avoided cost calculations. In addition to transmission investments related to distribution projects, CMP also provided similar load-growth-related investments associated with the non-PTF transmission costs. In estimating the avoided non-PTF cost, Synapse assumed these needs to be driven by the ISO New England CELT forecast. Synapse also applied a real levelized carrying charge and an avoided O&M allowance based on data provided by CMP. Since Synapse had limited data regarding matching of the CMP's capital investment time periods with the load growth, Synapse presented a range of values based on different assumptions of time periods for both the capital investments and the load growth. EMT chose to use the mid-point value across this range.

10.4. Localized value of avoided T&D

In addition to crediting demand-side measures with value for avoiding T&D costs across a service territory, it may also be necessary to estimate the value of these measures in a location-specific context. One example includes the evaluation an NWA (or hybrid solution) as an alternative to a proposed or potential traditional infrastructure-based solution to a projected reliability issue. To comprehensively estimate the value that DERs, namely energy efficiency and demand response, provide to localized T&D systems, program administrators can develop and rely on localized T&D values. This section describes the approach developed in AESC Supplemental Study Part II: *Localized Transmission and Distribution Benefits Methodology* (Supplemental Study) to AESC 2018 at the request of a subset of the AESC 2018 Study Group. The section then surveys the landscape of location-specific avoided T&D methods and approaches in the region.[296]

Summary of supplemental study approach to localized T&D value

The key aspects of the Supplemental Study methodology are to:

1. Identify target areas and required load reduction
2. Determine benefits of targeted load reductions by identified target area

[295] Central Maine Power Company Annual Filing of Schedule of Transmission Line Rebuild or Relocation Projects, 35-A M.R.S.A. §3132(3); and Schedule of Minor Transmission Line Construction Projects, 35-A M.R.S.A. §3132 (3-A).

[296] Chang, M., J. Hall, D. Bhandari, P. Knight. May 1, 2020. *AESC Supplemental Study, Part II. Localized Transmission and Distribution Benefits Methodology.* Synapse Energy Economics for AESC Supplemental Study Group. Available at https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_II_Localized_TD.pdf

3. Calculate avoided cost ($/kW) based on the present value of deferred expenditures and the required load reduction

The following sections detail the three-step process for determining localized T&D values. We also describe current practices followed by participating utilities when evaluating NWAs. We recognize that the decision process for evaluating NWAs relative to traditional engineering solutions is a different process from quantifying the avoided T&D costs for DSM planning. These three steps will require program administrators to obtain information from their respective planning groups.

Step 1: Identify target areas and required load reduction

The localized T&D value requires the identification of target projects and required load reduction and duration in order to calculate the avoided cost. This first step of identifying target projects utilizes a utility's planning processes that identify system contingencies at peak load levels under normal and contingency operations.

Build on existing T&D planning

The first step in identifying target locations for evaluation is based on the results from utility's existing peak load forecasts at the transmission, sub-transmission, and distribution levels. The peak load forecasts should only account for program-related NWA components such as energy efficiency, PV, and demand response that are currently online and active.[297] The peak load forecasts should be conducted in accordance with the utility's T&D planning practices and regulatory requirements (typical forecasts of five to 10 years in the future for distribution planning and 10 years for transmission and sub-transmission planning). This process may involve developing resource-specific forecasts. Stakeholders may consider evaluating peak load forecasts to include any state/local/regional electrification goals mandated by current policy, if not required by statute.

Local transmission and sub-transmission: After estimating peak load levels, the next step is to establish the system planning criteria and performance objectives. The system planning criteria should be based on the utility's local transmission system planning guidelines and regulatory obligations. This would involve designing the system in accordance with any relevant standards and/or design practices. For example, in New England this may include planning criteria for the bulk electric system as defined by ISO New England, NERC standards, and Northeast Power Coordinating Council (NPCC). In addition, local standards may also apply (e.g., Maine's local "safe harbor" reliability standards). An example of system planning criteria would involve establishing the voltage operating ranges and loading criteria for system components under normal and contingency operation—such as normal, long-term emergency and short-term emergency limit ratings for each type of equipment, i.e., the loading at which the equipment can operate in normal and emergency situations.

[297] The load forecast should be the same for evaluating NWAs and traditional engineering solutions.

As part of the planning process, the planning group will run power flow simulations to identify the system contingencies and violations under varying system configurations. This may include understanding and applying the specific contingency standards (e.g., loss of element contingency such as N-0, N-1, N-1-1) that define the minimum infrastructure necessary to maintain security standards depending on the needs of the specific region. At a transmission level this is typically done through load flow analysis software such as Siemens' PSS/E.[298] The analysis should also estimate the required load reduction in order to mitigate the contingency.

Distribution system: The distribution system planning process will follow a similar process as transmission planning. Distribution planning requires projecting the peak load. This should include summer and winter peak load forecasts at a substation and circuit level. The peak load forecast should be done over a timeline that is consistent with the utility's distribution planning process. Depending on the utility, this forecast is typically done over a 10-year period.

The next step involves setting up the design criteria for planning of the distributions system. This includes establishing criteria for equipment loading, phase balancing, and ranges of system voltages, etc. Following this, a circuit analysis is conducted to identify where planning criteria and design threshold violations exist and where the system constraints are expected to occur. This is typically done using distribution system planning tools, e.g., Eaton's CYME software to assess the critical load levels, thermal, and voltage violations.[299] This step would also involve estimating the load reduction required to mitigate any identified contingencies.

Distribution system analysis should also include a process to identify potential areas where there may be reliability concerns that could be mitigated through NWA solutions.

Considerations

To prioritize areas for targeted NWAs, utilities currently consider various additional factors before assessing the potential for an NWA option. For example, utilities may establish minimum threshold criteria to meet when addressing a system contingency or considering an NWA as a resource option.

Utilities also currently consider the timeline required for building the NWA and whether this can be done in time to avoid the identified contingency or violation that it is meant to address based on local conditions. There are issues that may not be considered imminent or immediate concerns (e.g., issues that may have been accepted for many years) and should also be addressed accordingly. For example, contingencies that have sufficient lead time could be considered for NWA solutions whereas projects with imminent needs may not be suitable for NWAs.

[298] Siemens. Last accessed March 10, 2021. "PSS®E – High Performance Transmission Planning and Analysis Software." *new.siemens.com*. Available at https://new.siemens.com/global/en/products/energy/energy-automation-and-smart-grid/pss-software/pss-e.html.

[299] CYME. Last Accessed March 10, 2021. "CYME International" *Cyme.com.* Available at http://www.cyme.com/

In addition, the severity and nature of the overload (e.g., the contingency number) are a consideration for the NWA process. The conditions under which the constraint or planning violation has been identified should be factored in the analysis. This might include examining the degree to which the constraint is present in normal conditions or extreme conditions (such as hot weather). Utilities also consider the nature of the contingencies in terms of whether they are suitable applications for an NWA. In identifying target areas where there are concerns about backing up critical loads, these areas should not be automatically disqualified from NWA consideration—instead hybrid solutions between the NWA and a wires solution could also be considered and evaluated by the planning group.[300]

DSM planning and implementation

On the energy efficiency side, there is need to factor in the lead time for marketing, implementation, and verification of DSM under an NWA solution. As noted in the responses provided by the utilities and stated above, current NWA evaluation processes require a window of time prior to the need to start construction on T&D infrastructure. In their DSM planning processes, program administrators should also factor the amount of DSM that could be based on potential annual load reduction (percent) by class and projected overload, as well as estimates of distributed generation and storage capacity. Conversely, a conventional engineering solution will also take time, especially if it requires separate regulatory approval and other siting review.

Identifying expenditures avoidable by load reductions

This section describes an approach to identifying expenditures that are avoidable by load reductions. It incorporates ideas from existing methodologies used by utilities to identify regions suitable for NWAs.[301]

In identifying the expenditures avoidable by load reductions, first it is necessary to identify the magnitude, duration, and coincidence of the load reduction compared to the location and the timing of the traditional utility solution that would solve any system contingencies. Any constraints identified should be listed as such based on the first year that the constraint is identified. As discussed above, this should be identified through the system power flow analysis. At minimum, most utilities consider load growth and reliability as the expenditures that can be avoided by NWAs.[302] However, other projects may also have some suitability in replacing a wires solution.

If a project addresses both NWA-eligible constraints and also non-NWA-eligible constraints, the costs for such projects should be broken down between those that are NWA-eligible and non-NWA-eligible in estimating the avoided cost expenditures. The utility should clearly identify which investments are

[300] As the availability and granularity of data improves through technologies and planning advancements, we anticipate improvements in methodology and applicability to more feeders.

[301] This methodology does not comment on the accessibility of detailed load, engineering, and cost data for feeders and components.

[302] While overall system load growth may be flat or declining for a given utility, there still may be individual feeders that are experiencing load growth.

considered as avoidable or deferrable through an NWA and the expenditures identified should be estimated in accordance with the utility capital investment planning guidelines. The expenditures should include operating expenses (e.g., reconfiguration) and capital investments and O&M associated with new facilities (net of any savings from retiring old equipment).

Utilities may establish a traditional engineering solution cost threshold before considering NWA solutions. Small projects that can be solved through traditional utility options (low-cost load transfers, etc.) may be less costly than procuring an NWA solution. Similarly, longer-term projects that do not have an imminent need and are above an established cost threshold may be more suitable projects for NWA consideration.

Identify type and period of required reduction

After identifying the expenditures that are avoidable by targeted load reductions, it is critical to identify the time at which the required load reduction is needed. This involves answering questions such as:

- Does the load reduction need to occur in a specific season?
- Does the load reduction need to occur in specific hours of the day?
- Over how many hours or days must the load reduction occur?

In addition, it is important to identify the number of years in which the reduction must occur. For example, if the goal is to defer an expenditure for three years, and the load is expected to exceed the system's capability for all three of those years, then an effective load reduction plan requires the load reduction to sustain for three years. Program administrators will need to coordinate with the utility's distribution planning group to ensure that localized demand reduction programs will meet the planning criteria as an appropriate solution.

Step 2: Determine benefits of targeted load reductions by identified target area

When calculating the avoided T&D costs, users should quantify the reduced present value of deferred expenditures. The annualized present value should reflect the utility's cost of capital, income taxes, property taxes, and insurance over the life of the equipment. To do so, one must first calculate the real carrying charge (RCC) that is expressed as a percentage. In general, the RCC equals the weighted average cost of capital (WACC), plus income tax, property tax, associated insurance, and O&M:[303]

$$RCC = WACC + Income\ Tax + Property\ Tax + Insurance + O\&M$$

[303] See Section 10.1 for a more detailed discussion of real carrying charge. The associated insurance and O&M costs may be expressed as a percentage of the deferred expenditure being analyzed.

The RCC should then be used to calculate the reduced present value of the avoided expenditures. For example, if the utility's RCC is 15 percent, then a $10 million investment would have an annualized expenditure of $1.5 million per year ($10 million x 15 percent).

There may be situations where a DSM load reduction defers a specific project by some period of time. For those situations and for the purposes of simplifying a more complex process, we recommend that the deferral value represents the traditional engineering expenditure reduced by the RCC and then discounted by the real discount rate.[304] In our illustrative example, if the RCC is 15 percent and the real discount rate is 3.37 percent, a 1-year deferral would have an avoided cost value of 85.5 percent (0.855 = 1 – [0.15 * (1 – 0.0337)]).

Step 3: Calculate avoided cost ($ per kW)

The next step is to calculate the avoided cost in terms of dollar per kilowatt (measured in $ per kW) for each identified target area.[305] To do so, program administrators must first compile:

1. The present value of the benefits from the deferral or avoidance of load-related expenditures identified in Step 2, above; and
2. The required load reduction, in kilowatts, required to achieve the deferral or avoidance of said expenditures.

Next, program administrators should divide the present value of the benefits from deferral or avoidance by the required load reduction to arrive at a localized avoided T&D value in dollars per kilowatt, by target area.

This value can serve as the conceptual average value for which to evaluate load reduction resources and technologies between the planning and energy efficiency groups. In other words, the average cost of the load reduction strategies used to achieve deferral or avoidance should be less than the calculated localized avoided T&D value, which is the value of the traditional engineering solution. If the average cost per kilowatt is greater than the localized avoided T&D value, then the avoidance or deferral portfolio costs more than the load-related expenditures that are targeted for deferral or avoidance. In these cases, alternative portfolios should be evaluated. If none are found to be cost-effective relative to the traditional engineering solution, the traditional engineering solution should be pursued.

Conceptually, it may be helpful to use the localized avoided T&D values as guidelines when compiling a portfolio to achieve the required load reduction. To the extent possible, program administrators should concentrate on achieving the required load reduction at lower costs per kilowatt than the avoided costs.

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[304] For the purposes of this methodology, we do not address any probabilistic planning issues that may arise from the continued deferral or acceleration of specific distribution project due to changes in localized loads. A more detailed analysis would require the re-running of power flow analyses based on changed loads that may result in the determination of a different engineering solution.

[305] This methodology does not address issues regarding operational control or visibility associated with the T&D system.

However, specific resources may be less than or even greater than the average avoided cost, as long as the total portfolio cost is less than the localized avoided cost T&D value.

Evaluation of current utility methods

AESC 2021 includes a rubric, developed in parallel with the rubric used in Section 10.3: *Survey of utility avoided costs for non-PTF transmission and distribution* above, to survey current utility methods for quantifying the value of demand-side measures in avoiding or deferring geographically localized investments. The evaluation rubric for localized T&D methods is built on a similar structure to the Supplemental Study, but it is more flexible (and more focused on the raw data sources and approaches to analysis) to reflect different approaches to calculating these values and the relative lack of maturity of this aspect of avoided cost analysis.

The Synapse Team surveyed the utilities in the Study Group regarding their approaches to localized avoided T&D values. The following section describes our review of data and methods provided by participating utilities.

Below, we present summary tables of the evaluation rubric, applied to each utility that responded to the request for information about its methodology about the current locational valuation/NWA methodologies. Table 115 provides a general summary of methodologies related to identification of candidate locations for NWAs and the related load forecast methodologies. Table 116 provides specific criteria/thresholds for selection of a locations as an NWA. Table 117 and Table 118 provide a summary of specific design/engineering criteria that are applied at the T&D level.

Table 115. Summary of location-specific evaluation methodologies and load forecast processes

Criterion	Eversource MA/NH/CT	National Grid MA	National Grid RI	United Illuminating CT	Vermont
Existence of a process to establish a location-specific value for avoided T&D costs in candidate locations for NWAs	Yes	Yes	Yes	No	Yes
Existence of a process to identify and/or select candidate locations for NWAs	Yes	Yes	Yes	No	Yes
Existence of a process for quantification of the required load reduction from these locations for calculation of the avoided costs	Yes	Yes	Yes	No	Yes
Whether the identification of these locations based on utility load forecasts	Yes	Yes	Yes	No	Yes
Granularity of load forecasts used by the utilities in identification of these locations.	Transmission and substation	System Level	System Level	N/A	Circuit Level
Inclusion of the following in the load forecasts:					
Operational EE	Yes	Yes	Yes	N/A	Yes
Operational PV	Yes	Yes	Yes	N/A	Yes
Operational DR	Only Eversource-sponsored DR	Yes	Yes	N/A	Yes
Inclusion of the following in the load forecasts:					
Projected EE	Yes	Yes	Yes	N/A	Yes
Projected PV	Yes	Yes	Yes	N/A	Yes
Projected DR	Only Eversource-sponsored DR	Yes	Yes	N/A	Yes
Inclusion of any electrification goals or mandates reflected in current policy	Yes	Yes	Yes	N/A	Yes

Notes: For Eversource, exact processes may vary across individual states between New Hampshire, Massachusetts, and Connecticut.

Table 116. Summary of processes for identifying locations that would benefit from load reductions

Criterion	Eversource	National Grid		United Illuminating	Vermont
	MA/NH/CT	MA	RI		
Whether the load growth forecasts are conducted in concert with the utility's T&D planning	Yes	Forecasts feed into assessment	Forecasts feed into assessment	N/A	Yes
Whether the utility applies a minimum threshold load criterion for qualification of a location in being considered for an NWA/used to calculate location-specific avoided costs	Yes	Yes	Yes	N/A	Yes
The existence of threshold load criteria used by the utility in identifying the target locations	Yes	Yes	Yes	N/A	Yes
Whether the utility develops a specific timeline for qualification of a location in being considered for an NWA/used to calculate location-specific avoided costs	Yes	Yes	Yes	N/A	Yes
Is there a timeline established for identification of a targeted location	Yes	Yes	Yes	N/A	Yes

Table 117. Summary of processes for identifying target locations that would benefit from load reductions at the transmission level

Criterion	Eversource	National Grid		United Illuminating	Vermont
		MA	RI		
Whether there is consistency with the utility's local transmission planning guidelines and regulatory obligations	Yes	Not applicable, screening occurs for sub transmission projects only	Not applicable, screening occurs for sub transmission projects only	No	Yes
Whether the targeted locations are identified through power flow simulations	Yes	Not applicable	Not applicable	No	Yes
Tools used for power flow modeling for this purpose	PSS/E, TARA	Not applicable	Not applicable	Not applicable	Not specified
How far into the future are these locations identified	10 years	Not applicable	Not applicable	Not applicable	10 years
What specific contingency standards are applied	NER , NPCC, ISO-NE Planning Eversource SYSPLAN-01 – Eversource Energy Transmission System Reliability Standards	Not applicable	Not applicable	Not applicable	ISO-NE, NERC, and other applicable reliability planning criteria
Are hybrid NWA solutions considered	Yes	Not applicable	Not applicable	Not applicable	Yes
Cost threshold for the traditional solution	Considered but details not specified	Not applicable	Not applicable	Not applicable	>$2.5M
Timeline criteria for the start of construction of the traditional solution	Considered but details not specified	Not applicable	Not applicable	Not applicable	≥2 years but <10 years
Load reduction and/or off-setting generation requirement	Considered but details not specified	Not applicable	Not applicable	Not applicable	1-3 yrs in future = 15% peak load 5 yrs in future = 20% peak load 10 yrs in future = 25% peak load

Table 118. Summary of processes for identifying target locations that would benefit from load reductions at the distribution level

Criterion	Eversource	National Grid MA	National Grid RI	United Illuminating	Vermont
Whether the utility applies specific design criteria (for equipment loading, phase balancing, and ranges of system voltages, etc.) in identifying these locations?	Yes	Yes	Yes	No	Yes
The existing design criteria that are applied for this purpose	Equipment Loading limits, reliability targets, voltage limits, resiliency goals; Anti-islanding, flicker/transient limits, fault and short circuit, reverse flow	Yes	Yes	Not applicable	Yes
Consistency of the design criteria with utility distribution planning criteria that are applied in identifying traditional engineering solutions at the distribution level	Yes	Yes	Yes	Not applicable	Yes
Whether the targeted locations are identified through power flow simulations	Not initially	Yes, after initial assessment	Yes, after initial assessment	Not applicable	Yes
Tools used for power flow modeling for this purpose	Synergi, CYME, PSCAD	Not specified	Not specified	Not applicable	CYME
Are hybrid NWA solutions considered	Yes	Yes	Yes	Not applicable	Yes
Cost threshold for the traditional solution	>$1M	≥$500K	>$1M	Not applicable	>$2M or >$250K if relieving a delivery constraint
Timeline criteria for the start of construction of the traditional solution	2 years, less than 7 years from IRP filing date	18 months	30 months	Not applicable	≥2 years but <10 years
Load reduction and/or off-setting generation requirement	>30MW	Load reduction <20% of relevant peak load	Load reduction <20% of relevant peak load	Not applicable	25%

The following subsections present short descriptions of the methods used by each responding utility.

National Grid (Massachusetts and Rhode Island)

In both Massachusetts and Rhode Island, National Grid has a process to consider NWAs as part of its distribution planning process for distribution and subtransmission capital projects and system needs. National Grid identifies system needs as a result of studies, operational issues, process safety issues, occupational safety issues, regulatory requirements, and/or customer requests.[306] If the annual planning process identifies a system need, and that location passes the state-specific NWA screening criteria, then the project is shifted to an NWA analysis team for further review and analysis of the system need. The screening criteria for each state are shown in Table 119 below.

Table 119. National Grid NWA screening criteria

Criteria	Massachusetts	Rhode Island
Project Type Suitability	Project types include Load Relief and Reliability. Other types have minimal suitability and will be reviewed as suitability changes due to state policy or technological changes.	Project types include Load Relief and Reliability. The need is not based on asset condition. If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.
Timeline Suitability	Start of construction is at least 18 months in the future.	Start of construction is at least 30 months in the future.
Cost Suitability (Cost of Wires Solution)	Greater than or equal to $500K	Greater than $1M

Source: National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 2020.

The avoided cost is based on a NPV calculation based upon costs and benefits of the NWA solution, as well as the avoided costs of not implementing some (in the case of a hybrid solution) or all of the traditional wires solution.

National Grid also considers hybrid NWA opportunities during screening. These are an NWA solution, or a combination of NWA solutions, that addresses part of a specified system need with the rest of the system need addressed by a wires solution.

Table 120 summarizes the NWA methodology employed by National Grid, as well as recommendations for improvement.

[306] National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 2020.

Table 120. Assessment of National Grid's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Methodology for Identification of Locations	National Grid has a documented process and guidelines for screening NWAs.	-	Access to analysis and the NWA screening tool would increase transparency.
Transmission Specific NWA Criteria	-	-	-
Distribution Specific NWA Criteria	National Grid has a documented process which outlines the types of projects that can replace traditional solutions for NWA consideration. National Grid has criteria in place for the type of wires projects suitable for NWAs. These include criteria for type of project (load relief, reliability, non-asset condition), timing, and cost.	-	-

United Illuminating

Currently, United Illuminating does not have a regulatory-approved NWA process in place within the state of Connecticut.

Eversource (Connecticut, Massachusetts, and/or New Hampshire)

Eversource has a documented process and framework for identifying locations where DSM could be applied to meet a system need.[307] The need for an investment at a particular location is identified as part of the distribution planning process which accounts for all planned and existing system upgrades including the DERs. The process involves using an in-house screening tool that looks at how NWA approaches can replace traditional solutions. The tool provides a comparison of the revenue requirements between an NWA and deferring a traditional solution in assessing the locational value of an NWA.

For use in the screening tool, Eversource develops a portfolio of possible solutions and technologies which involves market research and gathering information from vendors and suppliers through RFIs (Request for Information). Possible solutions are evaluated based on longevity, dependability, and the specific need identified. These technologies are integrated to the screening tool which is designed to provide a preliminary identification of the NWA solution and whether such a solution will meet the reliability and performance needs of the system.

[307] Survey To Evaluate Program Administrators Avoided T&D methodologies. Responses received on November 16, 2020.

In screening for NWAs, Eversource considers various criteria for identifying locations and selecting technologies including the magnitude of the need (applying N-0 and N-1 criteria to assess the required capacity of the solution), duration of the need, the time of day of occurrence of the need, and the frequency at which the need occurs.

Distribution Planning Screening Criteria

Non-wires candidates include:[308]

- Projects that are capacity-related
- Projects that can be deferred via deployment of NWAs
- Hybrid Solutions: combined deployment of NWAs paired with a traditional system

Some specific suitability criteria and threshold that are excluded from NWA consideration are:

- Upgrades that impact old or failing assets, or those scheduled to be replaced
- Upgrades below a financial threshold (have a projected cost of at least $1 million)
- Upgrades with immediate needs (less than 2 years). Projects must have planned in-service date at least 3 years after the date of the Least Cost Integrated Resource Plan (LCIRP) filing.
- Projects require more than 30 MW of peak load relief within seven years of the latest LCIRP filing.

Transmission Planning Screening Criteria

Eversource is required to comply with the following reliability and planning standards when planning its transmission system:[309]

- NERC TPL-001-04 - Transmission System Standards
- NPCC Regional Reliability Reference Director #1—Design and Operation of the Bulk Power System
- ISO New England Planning Procedure 3 (PP3)—Reliability Standards for the New England Area Bulk Power Supply System

[308] New Hampshire Public Utility Commission. October 1, 2020. "Eversource Least Cost Integrated Resource Plan." *Puc.nh.gov.* Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-161/INITIAL%20FILING%20-%20PETITION/20-161_2020-10-01_EVERSOURCE_ATT_2020_LCIRP.PDF. Appendix D.

[309] Massachusetts Department of Public Utilities. Last accessed March 11, 2021. "Petitions of Western Massachusetts Electric Company d/b/a Eversource Energy Pursuant to G.L. c. 164 72 and G.L. c. 40A 3."Available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9164120#page=54. Pg. 54-57

- Eversource SYSPLAN-01—Eversource Energy Transmission System Reliability Standards

Specific transmission suitability criteria for Non-Transmission Alternatives ("NTAs") also include response time to contingency conditions, minimum amount of operation time that resource is available for clearing of the contingency conditions, and land availability.[310]

Table 121 summarizes the NWA methodology employed by National Grid, as well as recommendations for improvement.

Table 121. Assessment of Eversource's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Methodology for Identification of Locations	Eversource appears to have a documented process and standardized framework for identifying locations where NWA could be applied to meet a system need on the distribution system.	For NWAs on the distribution system, access to the analysis (e.g., the NWA screening framework) would increase transparency.	-
Transmission Specific NWA Criteria	Targeted locations are identified through power flow simulations and reliability needs; the methodology for evaluation is consistent based on utility's local transmission planning guidelines and regulatory obligations. Eversource uses specific criteria and thresholds to exclude locations where NTAs are not suitable (minimum response time to contingency conditions, development time, land requirements). These may vary depending on the specific requirements of the project. Eversource focuses the NTA analysis on utility-scale resources; forecasted distributed generation, energy efficiency, and demand response are already used, where applicable, to reduce transmission system needs via inclusion in the ISO New England and Eversource load forecasts.	-	-
Distribution Specific NWA Criteria	Eversource has a documented process which outlines the types of projects that can replace traditional engineering solutions for NWA consideration; it also includes in a specific set of suitability criteria for qualification of a location that is suitable to NWA consideration including cost threshold, timeline and the quantity of load reduction required.	-	-

[310] "Non-Transmission Alternative" is the terminology used by Eversource in referring to NWA's at a transmission level.

Unitil (Massachusetts and New Hampshire)

Unitil has a documented process for identification of NWA opportunities. Per this process, Unitil applies design criteria for planning of the distribution and the transmission systems. At the distribution-system level, Unitil establishes a 90 percent planning threshold of seasonal rating for loads on substation transformers, stepdown transformers protective devices and other distribution circuit elements.[311] In addition, at the transmission and distribution levels, NWA projects are reviewed for any piece of major equipment that is expected to exceed 80 percent of its seasonal normal rating during the five-year study period and exceed 90 percent of its seasonal normal rating in year five of the study period during normal operating conditions.[312] The company indicated that the 80 percent threshold accounts for lead times needed to implement NWA solutions.[313] Unitil assumes a minimum of three years to receive, evaluate, and implement NWA proposals.[314] In addition, Unitil typically considers NWAs to be suitable in addressing loading and/or voltage constraints but not suitable for condition-based replacement projects.[315] Projects that address aging equipment may still be evaluated for NWAs, but this may not result in the issuance of an NWA RFP.

To estimate expenditures, Unitil has established a traditional engineering solution cost threshold before considering NWA solutions. Unitil has assessed that NWAs would generally not be evaluated if the recommended traditional option has an estimated cost of less than $250,000.[316]

Should a traditional engineering project meet the above criteria, Unitil will then issue an RFP for NWA solutions. Proposed NWAs are then reviewed through an evaluation process to score relative options for the company.

Vermont

Vermont's planning process are split into two phases.

<u>Transmission Level Process</u>

Every three years, the Vermont Electric Power Company (VELCO) publishes its LRTP. The LRTP analyzes the transmission system, identifies where the system does not meet design and reliability criteria, and describes the transmission alternatives to resolve the concerns.

Within the LRTP, VELCO applies the bulk transmission screening process originally adopted by the Vermont System Planning Committee (VSPC) and submitted to the Vermont Department of Public

[311] Unitil. Distribution Planning Guide. November 19, 2019. Page 8.

[312] Id. Page 8.

[313] Id. Section 4.3.

[314] Unitil. Project Evaluation Procedure, Page 3, July 2018.

[315] Unitil. Project Evaluation Procedure, Page 4, July 2018.

[316] Unitil. Project Evaluation Procedure, Page 3, July 2018.

Service (PSD) in Docket 7081. This screening process helps to determine if there is potential for the deficiency to be resolved through energy efficiency and/or alternatives such as generation or demand response (or a hybrid of transmission with efficiency and/or generation). For any transmission deficiency that screens, the PSD requires a Reliability Plan. In Vermont, Reliability Plans are synonymous with non-transmission alternatives (NTA).

Any affected distribution utility then drafts a project-specific action plan (PSAP) as required by the Docket 7081 Memorandum of Understanding. PSAPs describe a process for moving a deficiency from identification through to implementing a solution.

Sub-transmission and distribution process (geographic targeting)

Distribution utilities identify distribution-level constraints for consideration by VSPC and consider bulk/predominantly bulk transmission-level constraints once an LRTP is published, as described above.

Distribution constraints are typically identified in a utility's IRPs or at any time in intervening years by the utilities via the VSPC "Geotargeting" processes. As part of this process, the energy efficiency utility in consultation with the distribution utility and VELCO will determine the maximum achievable energy efficiency savings potential and costs. VSPC reviews the resulting recommendations for (1) areas needing new Reliability Plans, and (2) ending energy efficiency geographic targeting in any areas where analysis shows it is no longer cost-effective. The VSPC then it makes a recommendation to the PSD. A Reliability Plan is required for distribution constraints identified by distribution utilities in their IRPs or otherwise that screen in for full analysis using the Distributed Utility Planning (DUP) screening tool from Docket 6290.

There have not been any geographic targeting locations identified since 2012. According to the survey response as part of AESC 2021, Vermont noted that 15 percent of Green Mountain Power's substations are at thermal loading capacity due to backflow of distributed generation. This means that energy efficiency in some cases could lead to increased costs on the system. For example, if a substation is at capacity increased efficiency could result in the dumping of renewable generation or require increased investments to ensure reliability. While this issue is currently limited to a small number of hours, it is anticipated to become exacerbated over the next decade as more renewable energy comes online to meet Vermont's clean energy goals.

Table 122 summarizes the NWA methodology employed by Vermont, as well as recommendations for improvement.

Table 122. Assessment of Vermont's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Methodology for Identification of Locations	Vermont has a robust framework and criteria for identifying transmission, sub-transmission, and distribution-level NWAs.	-	-
Transmission Specific NWA Criteria	Targeted locations are identified through VELCO LRTP using power flow simulations and reliability. The methodology for evaluation is consistent with transmission planning guidelines and regulatory obligations. Vermont has criteria thresholds for excluding locations where NWAs are not suitable (regarding asset condition, cost thresholds, and timeline).	-	-
Distribution Specific NWA Criteria	Vermont has a screening tool specific to distribution-level NWAs. The screening tool contains criteria for excluding locations where NWAs are not suitable (emergency or failing asset, cost and timing thresholds).	-	-

Maine

In June 2019, the Maine Legislature enacted *An Act to Reduce Electricity Costs through Non- wires Alternatives*.[317] This Act identified a non-wires coordinator position in the Office of Public Advocate. Based on this, the criteria and process for identification of NWAs within the state of Maine is currently underway.

Consideration of location-specific costs and benefits in generation-constrained areas

Electrical systems have historically been designed for one-way flow of electrical power from central generators to distributed loads. However, the increased adoption of distributed generation resources is causing changes in that paradigm. This is particularly true in areas where generation can now approach or exceed load, but where the grid was designed and built to serve the load. Such locations have begun

[317] Maine Legislature, An Act to Reduce Electricity Costs through Non-wires Alternatives. http://www.mainelegislature.org/legis/bills/getPDF.asp?paper=HP0855&item=3&snum=129.

to appear in New England, including several locations in Vermont at both the transmission[318] and distribution[319] levels.

As part of its interconnection process, each generator is generally asked to pay for incremental changes in the grid that are required in order to interconnect safely and without impacting reliable service to customers. However, changes in load are not generally subject to the same type of analysis even though they could change the relationship between load and generation on a given circuit or other grid segment. Changes in end-use load that result in increased load during times when the distributed generation is producing could have the effect of mitigating reliability concerns, reducing strain on transformers or other grid hardware, or allowing more generation to interconnect (thereby potentially advancing state energy policies). On the other hand, changes in end-use load that result in decreased load during times when the distributed generation is producing could exacerbate reliability concerns, increase strain on grid hardware, or cause curtailment of generation.

Many of the general principles and considerations of localized avoided T&D costs could apply in the context of generation-constrained areas, just as they apply in the context of load-constrained areas. For example, the analysis would need to identify the specific costs corresponding to changes in the grid configuration that could be avoided or created by a change in end-use energy demand. With sufficient information regarding costs and the impacts on relevant peak loads (or exports), it would be possible to calculate a location-specific avoided T&D cost value for interventions that increase load, and a location-specific cost caused for interventions that decrease load, using the same approach to location-specific avoided T&D costs described earlier in this section.

The temporal and locational characteristics of the need should be carefully described. For example, if the issue of concern is created on sunny days during shoulder seasons when loads are otherwise low, then changes in an end-use that operates only during the coldest days of winter would have no impact. The dynamic aspects of active demand management and load control measures that can respond to grid conditions (such as different behavior on sunny and cloudy days) should be accounted for. This would entail accounting for the contribution during peak and off-peak hours rather than only accounting for the average behavior across all hours. Hourly load profiles and load shapes for measures, including

[318] See, for example, the discussion in Vermont Public Service Department. 2019. Vermont public Service Department. January 15, 2019. "Identifying and Addressing Electric Generation Constraints in Vermont." Vermont.gov. Available at https://publicservice.vermont.gov/sites/dps/files/documents/2019%20Act%20139%20Generation%20Constraints%20Report%20final.pdf.

[319] See Green Mountain Power. 2019. *Vergennes Generation Constrained Area* available at https://www.vermontspc.com/library/document/download/6603/VSPC%20Vergennes%20%285-21-1019%29%20%28002%29.pdf and Green Mountain Power. 2020. *Substation Generation Constraints: Hypothetical Constraint Review* available at https://www.vermontspc.com/library/document/download/7092/GMP_Hypothetical%20Constraint%20Review.pdf for discussions of issues in the vicinity of Vergennes, Vermont. Other presentations and notes from the Generation Constraints Committee of the Vermont System Planning Committee can be found here: https://www.vermontspc.com/vspc-at-work/subcommittees.

correlations with weather conditions where relevant, may be required to fully evaluate the impacts of traditional efficiency or electrification measures.

10.5. Avoided natural gas T&D costs

See Section 2.4: *Avoided natural gas cost methodology* for more information on the assumptions used in AESC with respect to natural gas transmission and distribution.

11. VALUE OF IMPROVED RELIABILITY

The reduction in electric loads can improve reliability in several ways. First, it can increase installed generation reserves and thus reduce the probability of inadequate supply under variable loads and generation outages. Second, the reduction decreases the thermal wear and tear on transformers and conductors and thereby reduce failures. Thirdly, it reduces the probability of overloads on T&D equipment to reduce faults. The last of these three categories overlaps with avoided T&D costs, since the ISO and utilities usually expand capacity to avoid system overloads. To the extent that lower loads result in less T&D capacity, the reduced capacity will tend to offset the benefits of lower loads. We have not been able to determine a method for accounting for that overlap. Hence, we do not estimate any value for reduced acute overloads on the delivery system, even though there are undoubtedly some situations in which lower load would allow the system to survive some equipment failures, without deferring capacity additions.

In AESC 2021, we find a default average VoLL value of $73 per kWh. This value is almost 3 times as large as the value derived in AESC 2018 ($26 per kWh in 2021 dollars). The change in the VoLL component is a result of updated information on VoLLs. This VoLL is then applied to the calculation of reliability benefits resulting from dynamics in New England's FCM to estimate cleared and uncleared benefits linked to improving generation reliability. In AESC 2021, we find 15-year levelized values of $0.47 per kW-year for cleared benefits and $8.45 per kW-year for uncleared benefits. These are 32 percent lower and 21 percent higher, respectively, than the same values estimated in AESC 2018, after adjusting for inflation. For cleared reliability, despite a higher VoLL, overall benefits are lower as a result of flatter supply curve assumptions for the capacity market. Changes to the capacity market have less of an impact on uncleared resources, which exist outside the capacity market. As a result, an increase in the VoLL produces an increase in the uncleared reliability value.

New in AESC 2021, we provide an estimated benefit for T&D reliability, based on data for National Grid Massachusetts. This section is provided as an example calculation of how different utilities could calculate their own T&D reliability benefit. This value would likely differ for each jurisdiction.

The following sections describe VoLL, the application of that value to generation reliability, and the potential for extension to distribution reliability.

11.1. Calculating value of lost load

In AESC 2018, we identified the most recent and detailed analysis of the VoLL to be that in the Lawrence Berkeley National Laboratory's (LBNL) 2015 study on *Updated Value of Service Reliability Estimated for Electric Utility Customers in the United States.* LBNL estimated costs of unserved energy for outages of one to four hours (typical of generation capacity shortfalls) on the order of $3 per kWh for residential,

$17 per kWh for large commercial and industrial (C&I), and $250 per kWh for small C&I—with shorter outages imposing higher costs per kWh (see Table 123).[320]

Table 123. Average cost per unserved kWh (2021 $ per kWh)

	Duration of Outage					
	Momentary	30 minutes	1 hour	4 hours	8 hours	16 hours
Medium & Large C&I	$218	$43	$25	$14	$15	$15
Small C&I	$2,575	$542	$337	$245	$305	$295
Residential	$35	$7	$4	$2	$2	$1

Source: LBNL. (2015). "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf. Table 1
Notes: Values originally reported in 2013 dollars have been converted into 2021 dollars.

Focusing just on the outages of one to four hours (typical of generation capacity shortfalls), these costs translate into values of on the order of $19 per kWh for medium and large C&I, $291 per kWh for small C&I, and $3 per kWh for residential.

For AESC 2021, we reviewed the recent literature on VoLL, looking for values more relevant to New England. We did not find any new domestic studies to add to our literature review conducted for AESC 2018.

In our updated literature review, we identified a relevant 2018 study from Europe written by Cambridge Economic Policy Associates: "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe."[321] The 2018 report estimated the VoLL for each European Union country, for residential customers and 13 types of non-residential customers (nine industrial sectors, construction, transportation, services and a combination of agriculture, forestry, and fishing). The values for some sectors vary strongly with the wealth of the country. To increase comparability with New England, we looked at the estimates for the 19 countries with gross domestic product (GDP) of at least half of New

[320] LBNL. (2015). "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States." Available at https://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf.

[321] Cambridge Economic Policy Associates Ltd. "Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe." July 2018. Available at https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf.

England's $77,574 average GDP per capita.[322] Table 124 shows the estimates for each of those countries and the simple average.[323]

Table 124. Residential VoLL in high-income European countries GDP per capita values

Country	Annual average VoLL for all sectors *2021 $/kWh*	Annual average VoLL for service sector *2021 $/kWh*	GDP per Capita *2021 $/person*
Austria	$12.09	$14.00	$60,631
Belgium	$12.89	$11.76	$56,041
Cyprus	$8.31	$6.24	$42,672
Czech Republic	$4.74	$5.46	$44,094
Denmark	$21.11	$15.56	$62,375
Estonia	$6.95	$3.84	$39,847
Finland	$7.11	$6.52	$52,517
France	$9.29	$9.60	$49,836
Germany	$16.66	$11.48	$58,183
Ireland	$15.46	$18.75	$93,644
Italy	$15.22	$10.51	$45,852
Lithuania	$6.20	$6.00	$40,175
Luxembourg	$18.15	$17.91	$123,535
Malta	$8.56	$6.01	$47,515
Netherlands	$30.79	$11.96	$61,438
Slovenia	$5.80	$6.25	$42,180
Spain	$10.58	$8.91	$44,138
Sweden	$7.41	$9.41	$57,450
United Kingdom	$21.34	$17.52	$50,348
Average	**$12.56**	**$10.40**	**$56,446**

Note: All monetary units have been converted into 2021 dollars.

The $12.56 per kWh average is much higher than the $3 per kWh LBNL estimate for residential customers. Since the average GDP per capita for these countries is $56,446, or 73 percent of the New England GDP/capita, the VoLL for New England households is likely to be higher. For the four highest-income countries, with an average GDP/capita similar to New England's, the average VoLL estimate is 45 percent higher, or $21.38 per kWh. We note that most of the factors that would influence VoLL (cold winters, hot summers, high reliance on computers and related equipment) are at least as powerful for New England as the average European country.

[322] GDP per captia data for New England calculated using U.S. Bureau of Economic Analysis and U.S. Census data (BEA. Last accessed March 3, 2021. "GDP and Personal Income." Bea.gov. Available at https://apps.bea.gov/iTable/iTable.cfm?reqid=70&step=1&acrdn=1) and (U.S. Census Bureau. 2019. "State Population Totals and Components of Change." Census.gov. Available at https://www.census.gov/data/tables/time-series/demo/popest/2010s-state-total.html)

Other than Luxembourg and Ireland, European national GDP per capita is uniformly lower than New England's.

[323] The VoLLs are from Table G.1 of the Cambridge Economic Policy Associates study. The per capita GDP values are from The World Bank. Last accessed March 11, 2021. "GDP Per Capita, PPP – European Union." *Data.worldbank.org.* Available at https://data.worldbank.org/indicator/NY.GDP.PCAP.PP.CD?locations=EU.

The Cambridge Economic Policy Associates study estimates of VoLL for non-residential customers do not map clearly onto the small-C&I and large-C&I categories of the LBNL study. Nor do the industrial sectors in the study map well onto important New England industries, such as biotech. The value for the services sector, which would include a large portion of major New England C&I customers (banking, real estate, data services) is about half of the LBNL estimate for large-C&I customers, at $10.40 per kWh for the nineteen countries. The result is more similar for the European countries most similar to New England in terms of GDP per capita, at $16.04 per kWh.

For AESC 2021, we average the findings from the LBNL and Cambridge Economic Policy Associates studies together for each category of customer. Then, using share-of-sales data from EIA's form 861, we calculate a weighted average (see Table 125). The resulting VoLL is $73 per kWh.

Table 125. Calculation of VoLL

	LBNL *2021 $/kWh*	CEPA Ltd. *2021 $/kWh*	Final *2021 $/kWh*	Sales shares *%*
Residential	$2.80	$12.56	$7.68	40%
Small C&I	$290.87	$10.40	$150.64	45%
Large C&I	$19.36	$10.40	$14.88	14%
Weighted Average VoLL			**$73**	

Notes: Sales shares are estimated using 2019 data from EIA Form 861. We assign "commercial" sales from EIA for Small C&I and "industrial" sales to large C&I.

11.2. Value of reliability: Generation component

We observe that reducing loads can improve generation reliability in three ways:

- Some resources that do not clear the FCA 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. They may also be available to assume the capacity obligations of resources that unexpectedly retire or otherwise become unavailable.
- Not all energy efficiency load reductions will clear in the capacity market or immediately affect the load forecast used to determine the amount of capacity acquired. Those load reductions will increase reserve margins.
- The operation of the ISO New England capacity market increases 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.

The following sections describe how we calculated this component for cleared measures and uncleared measures.

Calculating cleared reliability

In order to calculate cleared reliability benefits, we first assemble several input parameters. First, ISO New England annually publishes marginal reliability index (MRI) curves, which estimate the expected energy lost per MW of additional supply as the reserve margin rises. In AESC 2021, we examine the slope of the MRI curve at each auction's clearing price. The resulting value can be thought of as the estimated change in MWh of reliability benefits per megawatt of reserve. Values calculated in FCA 12 through 15 utilize the MRI curve published for each auction, while all auctions that take place after FCA 15 utilize the MRI curve published for FCA 15. Table 126 displays the estimated change in MWh of reliability benefits per megawatt of reserve, and how it varies with the capacity market clearing price.

Table 126. Change in MWh of reliability benefits per megawatt of reserve for Counterfactual #1 in rest-of-pool region

		Clearing price *2021 $/kW-month*	Δ MWh LOEE per MW *MWh / MW*
FCA 12	2021	$4.77	0.329
FCA 13	2022	$3.96	0.273
FCA 14	2023	$2.47	0.170
FCA 15	2024	$2.75	0.189
FCA 16	2025	$2.72	0.187
FCA 17	2026	$2.88	0.199
FCA 18	2027	$3.11	0.214
FCA 19	2028	$3.30	0.227
FCA 20	2029	$3.59	0.248
FCA 21	2030	$3.42	0.237
FCA 22	2031	$3.67	0.253
FCA 23	2032	$3.90	0.268
FCA 24	2033	$3.86	0.265
FCA 25	2034	$4.67	0.323
FCA 26	2035	$3.66	0.253

Note: Values for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Due to the slopes of the supply and demand curves, bidding an additional MW into the FCA at $0 per kW-month price shifts the supply curve to the right. This shifts out some smaller amount of capacity that would otherwise have cleared, and it results in the amount of cleared supply increasing by only a fraction of the additional supply. That fraction is small when the clearing price is set at a shallow part of the supply curve, and it increases if the clearing price is set at a steeper part of the supply curve (see Table 127). This value is calculated by dividing the supply price shift by the difference between the supply price shift and the slope of the demand curve at the demand value implied by the clearing price.

Table 127. Net increase in cleared supply for Counterfactual #1 in rest-of-pool region

		Clearing price	Net increase in cleared supply
		2021 $/kW-month	*%*
FCA 12	2021	$4.77	8%
FCA 13	2022	$3.96	7%
FCA 14	2023	$2.47	16%
FCA 15	2024	$2.75	17%
FCA 16	2025	$2.72	17%
FCA 17	2026	$2.88	16%
FCA 18	2027	$3.11	20%
FCA 19	2028	$3.30	20%
FCA 20	2029	$3.59	19%
FCA 21	2030	$3.42	20%
FCA 22	2031	$3.67	19%
FCA 23	2032	$3.90	18%
FCA 24	2033	$3.86	18%
FCA 25	2034	$4.67	79%
FCA 26	2035	$3.66	19%

Note: Values for other counterfactuals and regions can be found in the AESC 2021 User Interface.

The final component used to calculate cleared reliability benefits is a decay effect. Over time, customers will respond to lower prices by using somewhat more energy, including at the peak. In addition, lower capacity prices may result in the retirement of some generation resources and termination of some demand-response resources, which will result in these resources being removed 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). The decay schedule used for cleared reliability is the same as the one used for cleared capacity DRIPE (see Table 89, above).

Finally, we calculate the cleared reliability benefit by calculating the product of (a) the change in MWh of reliability benefits per megawatt of reserve, (b) the net increase in cleared supply, (c) the decay effect, and (d) the VoLL, as calculated above.[324] Table 128 describes the overall benefit for a measure installed in 2021. We note that these values are very small compared to the estimated avoided costs in many other categories.

[324] Note that the *AESC 2021 User Interface* allows users to specify their own VoLL, if they so choose.

Table 128. Estimated cleared reliability benefits for Counterfactual #1 in rest-of-pool region for measures installed in 2021, assuming a VoLL of $73 per kWh

		Δ MWh LOEE per MW	Net Increase in Cleared supply	Decay Schedule	Cleared reliability benefits
		MWh / MW	*%*	*%*	*2021 $/kW-month*
FCA 12	2021	0.329	8%	100%	$1.92
FCA 13	2022	0.273	7%	83%	$1.22
FCA 14	2023	0.170	16%	67%	$1.29
FCA 15	2024	0.189	17%	50%	$1.15
FCA 16	2025	0.187	17%	33%	$0.77
FCA 17	2026	0.199	16%	17%	$0.39
FCA 18	2027	0.214	20%	0%	$0.00
FCA 19	2028	0.227	20%	0%	$0.00
FCA 20	2029	0.248	19%	0%	$0.00
FCA 21	2030	0.237	20%	0%	$0.00
FCA 22	2031	0.253	19%	0%	$0.00
FCA 23	2032	0.268	18%	0%	$0.00
FCA 24	2033	0.265	18%	0%	$0.00
FCA 25	2034	0.323	79%	0%	$0.00
FCA 26	2035	0.253	19%	0%	$0.00

Note: Values for other counterfactuals, regions, and resource vintages can be found in the AESC 2021 User Interface. The "decay schedule" series is identical for measures installed in later years, except shifted by the relevant number of years.

Calculating uncleared reliability

Like cleared reliability, the calculation of uncleared reliability benefits requires the assembly of several input parameters.

The first is the estimated change in MWh of reliability benefits per megawatt of reserve. This parameter is the same as is used in the calculation of cleared reliability benefits (see Table 126, above).

Second, uncleared reliability benefits are grossed up to account for the impact of the reserve margin. As with uncleared capacity and uncleared capacity DRIPE, because uncleared reliability benefits accrue outside of the FCM, they are effectively "counted" in the demand side of the capacity auction. See Table 44, above, and surrounding text for more information on this effect.

Third, we assume that reliability has a phased impact on the load forecast. In contrast to uncleared capacity and uncleared capacity DRIPE, reliability is not dependent on the operation of ISO New England's load forecasting and capacity market. As soon as load is reduced, the reserve margin increases (since the uncleared capacity does not initially reduce capacity procurement) and reliability is improved. Hedging of capacity supply, either short- or long-term, does not reduce the reliability effect, as it does capacity DRIPE. Thus, the reliability improvement starts at 100 percent in the first year and persists until the load reduction affects the FCA. Unlike other uncleared avoided cost categories, which operate through the effect on the econometric load forecast, the reliability improvement from any given measure does not rise with the number of years it has been in place, but only by the increase in reserves for the year.[325]

Fourth, uncleared reliability benefits will gradually decay over time, as the load reduction is reflected in the load forecast, reducing the amount of capacity that ISO New England acquires. Eventually, the load reduction would be fully captured in the load forecast, and the reliability benefit would be extinguished. The decay of the reliability benefit of uncleared resources starts later and is more gradual than the one used for cleared resources, because the market does not react to the resources and reduce procurement until it is picked up in the load forecast.

Finally, we calculate the uncleared reliability benefit by calculating the product of (a) the change in MWh of reliability benefits per megawatt of reserve, (b) one plus the reserve margin, (c) the load forecast effect, (c) the decay effect, and (e) the VoLL.[326] Table 129 describes the overall benefit for a measure installed in 2021. Generally speaking, reliability effects of uncleared resources are greater than those of cleared resources. This is because the cleared resources immediately displace other resources, resulting in a smaller net gain in reliability. Uncleared resources increase reliability more than cleared resources do, for the same reason that uncleared resources have no immediate effect on capacity bills or prices—unclear resources are invisible to the capacity market.

Table 129. Estimated uncleared reliability benefits for Counterfactual #1 in rest-of-pool region for measures installed in 2021, assuming a VoLL of $73 per kWh

		Δ MWh LOEE per MW	Reserve Margin	Load Forecast Effect	Decay Schedule	Uncleared reliability benefits
		MWh / MW	*%*	*%*	*%*	*2021 $/kW-month*
FCA 12	2021	0.329	14%	100%	100%	$27.29
FCA 13	2022	0.273	14%	100%	100%	$22.82
FCA 14	2023	0.170	15%	100%	100%	$14.29
FCA 15	2024	0.189	15%	100%	100%	$15.79
FCA 16	2025	0.187	16%	100%	100%	$15.82
FCA 17	2026	0.199	13%	70%	100%	$11.45
FCA 18	2027	0.214	14%	50%	95%	$8.42
FCA 19	2028	0.227	14%	30%	87%	$4.94
FCA 20	2029	0.248	14%	10%	75%	$1.55
FCA 21	2030	0.237	14%	0%	60%	$0.00
FCA 22	2031	0.253	14%	0%	43%	$0.00
FCA 23	2032	0.268	14%	0%	27%	$0.00
FCA 24	2033	0.265	14%	0%	0%	$0.00
FCA 25	2034	0.323	14%	0%	0%	$0.00
FCA 26	2035	0.253	14%	0%	0%	$0.00

Note: Values for other counterfactuals, regions, and resource vintages can be found in the AESC 2021 User Interface. The "decay schedule" series is identical for measures installed in later years, except shifted by the relevant number of years.

[325] In this regard, the reliability benefit of unclear capacity operates more like avoided energy or cleared capacity than like uncleared capacity or capacity DRIPE.

[326] Note that the *AESC 2021 User Interface* allows users to specify their own VoLL, if they so choose.

Important caveats for applying reliability values

Unlike other uncleared avoided cost categories (e.g., uncleared capacity, uncleared capacity DRIPE) uncleared reliability avoided costs are summed over the time period that a measure is active. This is similar to the approach used to sum avoided costs for most categories.

Unlike other uncleared avoided cost categories, users should not apply a scaling factor (like the kind described in Appendix K: *Scaling Factor for Uncleared Resources*). The scaling factor reflects a demand measure's effect on the load forecast, which is a function of the number of daily peaks (the inputs to the ISO New England demand forecast regression) that are reduced by the measure. Because changes in reliability do not impact the load forecast, the scaling factor should not be used to adjust uncleared reliability benefits.

Other considerations: reliability impact on non-summer peak hours

Measures increase generation reliability to the extent that they reduce load at hours that would contribute to ISO New England's estimate of loss-of-energy expectation (LOEE). An efficiency measure that clears as 1 kW of supply in the capacity auction may provide more or less load reduction during the highest LOEE hours. We note that these hours may not necessarily coincide with ISO New England's definition of on-peak hours for on-peak resources (weekday hours ending 14-17 from June through August and hours ending 18 and 19 in December and January) or seasonal resources (hours in June through August, December, and January with load greater than 90 percent of the seasonal 50/50 peak), especially as solar generation reduces LOEE in sunny summer hours.

In setting the demand curve for each capacity auction (both the FCAs and the annual reconfiguration auctions), ISO New England derives various measures of generation risk, including loss-of-load expectation (LOLE), which is a measure of the fraction of time intervals for which supply might be inadequate, and the LOEE, the amount of energy that would not be served on average. ISO New England provided its risk results from the second annual reconfiguration auction for the 2022–2023 capacity compliance period (the period covered by FCA13), as shown in Table 130. All months other than the summer had zero risk in this analysis.

Table 130 suggests that only the reductions in the highest-net-load hours of the summer are likely to have any effect on reliability, at least in the near term.[327] That may change as electrification increases winter loads and storage flattens the effective peaks.

[327] See https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_I_Winter_Peak.pdf for more discussion on this.

Table 130. Monthly distribution of risk prices for capacity commitment period 2022–23, annual reconfiguration auction #2

	June	July	August	Annual
LOLE (days)	0.00066	0.02059	0.07868	0.09994
LOLE (hours)	0.00194	0.11075	0.43035	0.54303
LOEE (MWh)	0.953	119.184	524.418	645.153
Percentage by month				
LOLE (days)	0.7%	20.6%	78.7%	
LOLE (hours)	0.4%	20.4%	79.2%	
LOEE (MWh)	0.1%	18.5%	81.3%	

11.3. Value of reliability: T&D component

New to AESC 2021, we provide an example methodology of how utilities might calculate a value of reliability associated with T&D.

Theory

Reducing loads can also reduce overloads and violations of T&D planning standards, by:

- Leaving additional capacity across this system to accommodate flows from facilities or equipment that are forced out of service by non-load-related problems,
- Reducing overloads under extreme weather conditions, and
- Reducing wear on lines and transformers from the cumulative effects of many hours with high loads.[328]

The aging of transformers (both at substations and along primary feeders) primarily results from the breakdown of insulation due to heating. That deterioration can be driven by:

- Short periods of very high load levels: transformers typically can be operated at over 150 percent of their rated capacity for an hour or two, if they start cool.
- Long periods (such as many hours or days) of lower but still high loads, which heat up the insulation.
- Even more so, very high load levels following a long period of high loads.

Similar considerations also apply to underground T&D lines that are insulated in the ground. These underground lines and their insulation also heat up due to long periods of high loads.

[328] Other causes (tree, weather, animal contact, etc.) of outages are not load-related and are thus outside the scope of this analysis.

Some overhead lines are subject to a different set of load-related failure modes. Generally, the surrounding air cools the lines and reduces the effect of heat buildup at moderate load levels. However when lines are loaded near their thermal ratings, this can lead to deterioration of insulation (if they are insulated). High loads can also stretch and weaken the metal conductor, and reduce line clearance from the ground or other objects below the line. Stretched lines are more vulnerable to breakage from other stresses, such as wind load.[329]

We examined utility reports on distribution outages to attempt to estimate the amount of load lost due to potentially load-related equipment failure, as opposed to events such as tree, vehicle, or animal contact.

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 even when the T&D system does not change. By contrast, the reliability for a T&D element (e.g., distribution substation, feeder, line transformer, secondary lines) is not likely to improve for T&D equipment that is avoided by a load reduction.[330]

Example calculation

For the purposes of AESC 2021, we reviewed the 2019 outages in National Grid Massachusetts "Unplanned Significant Outage Report" in DPU 20-SQ-11, which included about 4,700,000 customer-hours of outage. Those hours were about 65 percent due to trees, with failed equipment accounting for over 14 percent (over 682,000 customer-hours), and other categories (lightning, animals, and other miscellaneous) totaling about 20 percent. The outages that National Grid listed as due to failed equipment included some that were clearly not due to electrical failure, such as broken poles, lightning arresters, and brackets; many categories that might conceivably be related to heavy loading (e.g., "tired fuses," fires, and failed switches, breakers, and reclosers); and a few likely to be load-related (failed transformers, underground cables, and splices). That last group of outages amounted to about 176,000 customer-hours, about 4 percent of the total outage hours. We note that some portion of these outages may be associated with deferred maintenance or defective parts, and may not ultimately be avoidable through load reductions.

Exhibit NG-HSG-3A to National Grid's filing in DPU 18-150 provides customer number and sales by class. The average non-streetlighting customer uses about 15 MWh annually, but many of the largest customers are served at primary or even transmission voltage. The customers served at secondary voltage would be exposed to more outages than customers served at primary voltage, and the transmission-level customers would not be affected by any of these distribution outages. Counting only

[329] Many overhead lines are self-supporting and thus vulnerable to stretching and physical stress. Line supported by much stronger steel messenger wire are less sensitive to the mechanical stresses.

[330] Logically, similar considerations would apply to the reliability of natural gas supply by LDCs, but that subject is beyond the scope of AESC 2021.

50 percent of the sales at primary and none of the sales at transmission, the average usage falls to 14 MWh per customer annually, or about 1.6 kWh per customer-hour.

Multiplying together the number of customer-hours related to load-related outages (about 176,000), 1.6 kWh per customer-hour and $73 per kWh VoLL yields a total annual cost of the potentially load-related outages of about $21 million annually. Dividing by total distribution sales of about 19.8 TWh, this resulting per-MWh cost is $1.04 per MWh. The load-related failures in 2019 were presumably due to accumulated damage over decades of service, but the energy delivered in 2019 will contribute to failures that occur in 2019 as well as future years. Hence, it appears reasonable to estimate the load-related costs of lost distribution reliability in future years to be similar to the cost derived from 2019 data. The distribution reliability cost may vary by time period, with potentially higher costs in peak hours than off-peak hours and higher costs in summer months than the rest of the year.[331]

The methodology of this analysis could be applied for other investor-owned utilities that file similar data, and for additional years. Similar data may be available from electric utilities in other states. We recommend that utilities or program administrators examine data local to their own jurisdictions and evaluate their own estimates of T&D reliability benefits.

[331] High winter loads may also contribute to the aging of transformers, but lower air temperatures reduce overheating and damage. For example, National Grid (MA) aims to change out residential transformers when they reach half-hour peak loads of 160 percent of rated capacity in the summer or 200 percent in the winter (see DPU 16-SG-11 Filing Attachment 2).

12. Sensitivity Analysis

The following sections detail the inputs and results of the sensitivity analysis. In AESC 2021, we evaluate avoided costs under three different sensitivities. These sensitivities include:

- A natural gas price sensitivity with higher gas prices than were used in Counterfactual #1 ("High Gas Price Sensitivity")
- A climate policy sensitivity, where avoided costs for energy efficiency are calculated under a hypothetical regional climate policy with increased levels of electrification and clean energy ("No New EE Climate Policy Sensitivity")
- A climate policy sensitivity which models energy efficiency along with increased levels of electrification and clean energy ("All-In Climate Policy Sensitivity")

These sensitivities were identified through consensus discussion among members of the Study Group.[332]

For each of these sensitivity cases, we find the following:

- In the High Gas Price Sensitivity, energy prices are 27 percent higher, capacity prices are 2 percent lower, RPS compliance costs are 8 percent lower, and non-embedded GHG costs are 21 percent lower. All prices are compared to Counterfactual #1.
- In the No New EE Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 52 percent higher, and RPS compliance costs are 12 percent higher. All prices are compared to Counterfactual #3. This sensitivity features a new avoided cost (the incremental regional clean energy policy compliance cost, or IRCEP), which captures the incremental cost of the region reaching 90 percent non-fossil generation by 2035. This category increases total levelized avoided costs by 0.9 percent.
- In the All-In Climate Policy Sensitivity, energy prices are 4 percent lower, capacity prices are 42 percent higher, and RPS compliance costs are 11 percent higher. All prices are compared to Counterfactual #2. The new IRCEP cost category increases total avoided costs by 0.4 percent, all else being equal.

All of the summary costs described above are framed in terms of 15-year levelized costs for summer on-peak for the WCMA region.

12.1. When and how to use these sensitivities

This section discuss caveats and considerations relating to the modeled sensitivities

[332] This discussion included the distribution of an informal survey by the Synapse Team. Other sensitivities considered, but not analyzed due to time and budget constraints, include a case examining more extended impacts of the COVID-19 pandemic (beyond the effects considered in the main counterfactuals) as well as other versions of a climate policy sensitivity.

High Gas Price Sensitivity

The first sensitivity (the High Gas Price Sensitivity) is modeled primarily because natural gas prices are one of the inputs to which the AESC Study is historically the most sensitive. AESC 2021 is no exception; one of the primary reasons for the decrease in energy values between AESC 2018 and AESC 2021 is the associated decrease in annual natural gas prices. The purpose of this sensitivity is to provide a set of potential avoided energy costs under a future in which natural gas prices prove to be higher than those modeled in the main counterfactuals.

Climate policy sensitivities

The No New EE Climate Policy Sensitivity models a future with ambitious levels of building electrification and transportation electrification, as well as a policy which achieves 90 percent clean energy regionwide by 2035. This sensitivity does <u>not</u> model any incremental energy efficiency installed in 2021 or any later year. This means that it is a suitable sensitivity for considering avoided costs for energy efficiency in a future with more ambitious climate regional policies.

The All-In Climate Policy Sensitivity models a future with ambitious levels of energy efficiency, building electrification, and transportation electrification, as well as a policy which achieves 90 percent clean energy regionwide by 2035. As a result, it can be interpreted not as an avoided cost, but as a projection of <u>expected</u> energy prices, capacity prices, and other price series in a future with ambitious climate policies. Or, it could be interpreted as a projection of avoided costs for energy efficiency and electrification measures beyond those modeled in this scenario. In other words, while the No New EE Climate Policy Sensitivity estimates avoided costs for the first unit or first many units of energy efficiency measures, the All-In Climate Policy Sensitivity estimates avoided costs for the <u>last</u> unit of energy efficiency, or the first unit of energy efficiency beyond what is modeled in this sensitivity.

There are a number of other important caveats to consider relating to the climate policy sensitivities:

- Both climate policy sensitivities model avoided costs under a very specific set of assumptions related to electrification and a hypothetical regional clean energy policy. Different assumptions related to either of these inputs could potentially yield different avoided costs than what are shown here. As a result, these sensitivities are likely most useful in terms of thinking about directions and orders of magnitudes of avoided costs, relative to the main AESC counterfactuals, rather than being useful as sources of avoided costs on their own.

- These sensitivities may be most useful for teeing up questions for future avoided cost studies. They highlight challenges in terms of framing, energy sector modeling, and clean energy policy design that have never before been considered in previous AESC studies. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.

- Some of the highest costs of a decarbonized grid are most likely after these sensitivities' modeling horizon (e.g., post-2035), when building and transportation electrification are expected to reach significant scale. The modeling horizons analyzed in these sensitivities (which are consistent with the 15-year detailed modeling period used in the rest of this report) may undercount avoided costs that occur post-2035. These avoided costs may be of particular importance for measures with lifetimes longer than 12-15 years that are being considered for implementation between 2021 and 2024. Avoided costs derived from these sensitivities would likely be more informative or useful in practical settings if years after 2035 were modeled in more detail. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.

12.2. Sensitivity inputs and methodologies

This section details the input assumptions and methodologies used in the construction of these sensitivities.

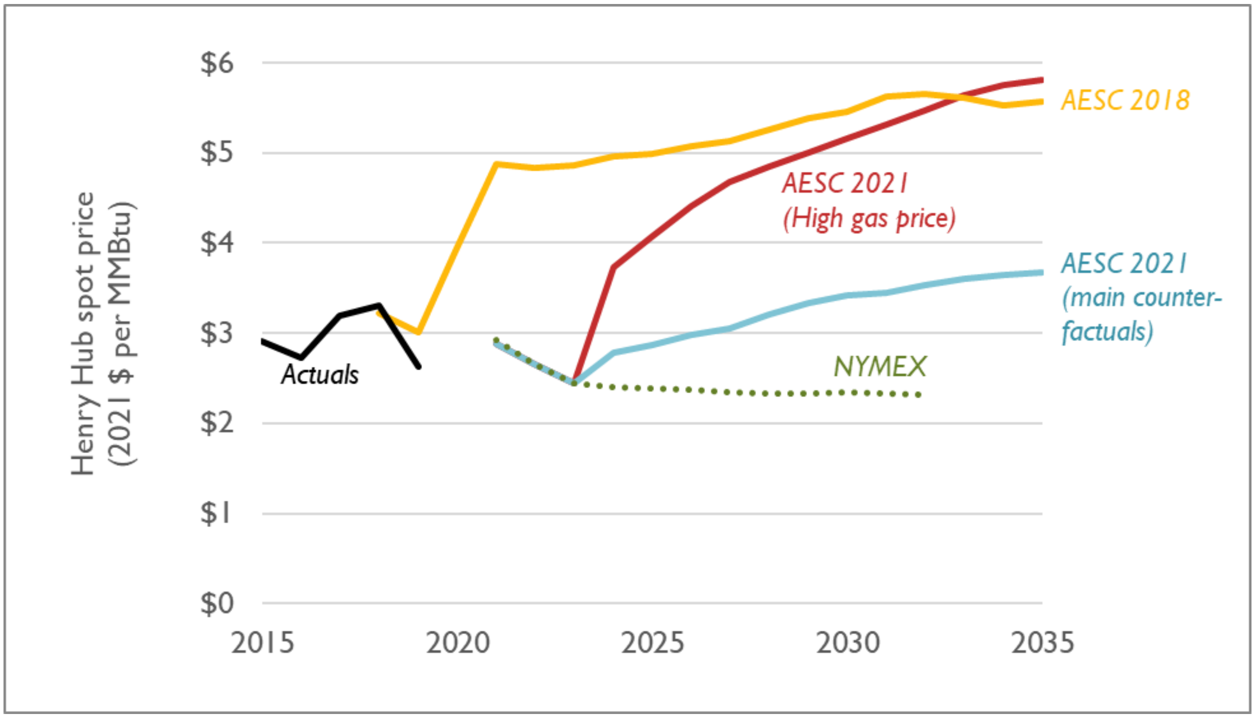
High Gas Price Sensitivity

The High Gas Price Sensitivity is a modification of Counterfactual #1. The primary change made in this sensitivity is a different assumption for long-term gas prices. Figure 52 illustrates the difference between the Henry Hub price used in the main four AESC 2021 counterfactuals and the gas price used in this sensitivity (other series are shown for comparative purposes). The high gas price is identical to the main price in 2021 through 2023. Between 2024 and 2035, the high gas price is 51 percent higher than the main case, on average.

The high gas price trajectory depicted in Figure 52 is created by swapping out the AEO 2021 Reference case series used to create mid- and long-term gas prices in the main four AESC counterfactuals for the AEO 2021 "Low oil and gas supply" case.[333] This series depicts a future with higher gas prices as a result of lower gas recovered per well and lower assumed rates of technological improvement (which would otherwise reduce costs and increase productivity). In this case, domestic natural gas production in 2035 is 30 Tcf, an 11 percent reduction compared to 2020 levels (for comparison, the AEO 2021 Reference case used as a data source for the gas price in the main AESC counterfactuals reaches 39 Tcf in 2035, a 14 percent increase compared to 2020).

[333] This was called the "Low oil and gas resource technology case" in earlier AEO studies, including the one used as a data source for AESC 2018. For more information on these cases, see "Annual Energy Outlook 2021: Case Descriptions." U.S. Energy Information Administration. February 2021. Available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/case_descriptions_2021.pdf.

Figure 52. Henry Hub price forecast in main AESC 2021 case and High Gas Price Sensitivity



We made no further changes to inputs for this sensitivity. This includes no changes to Algonquin basis prices, monthly price changes, or changes to load. Our modeling methodology otherwise followed the methodology described for the four main counterfactuals, as described above.

Climate policy sensitivities

The inputs for the two subsequent sensitivities are discussed together due a large overlap in assumptions. Generally speaking, the inputs in these sensitivities can be split into two categories: inputs that modify demand assumptions, and inputs that modify supply assumptions.

Modifications to demand

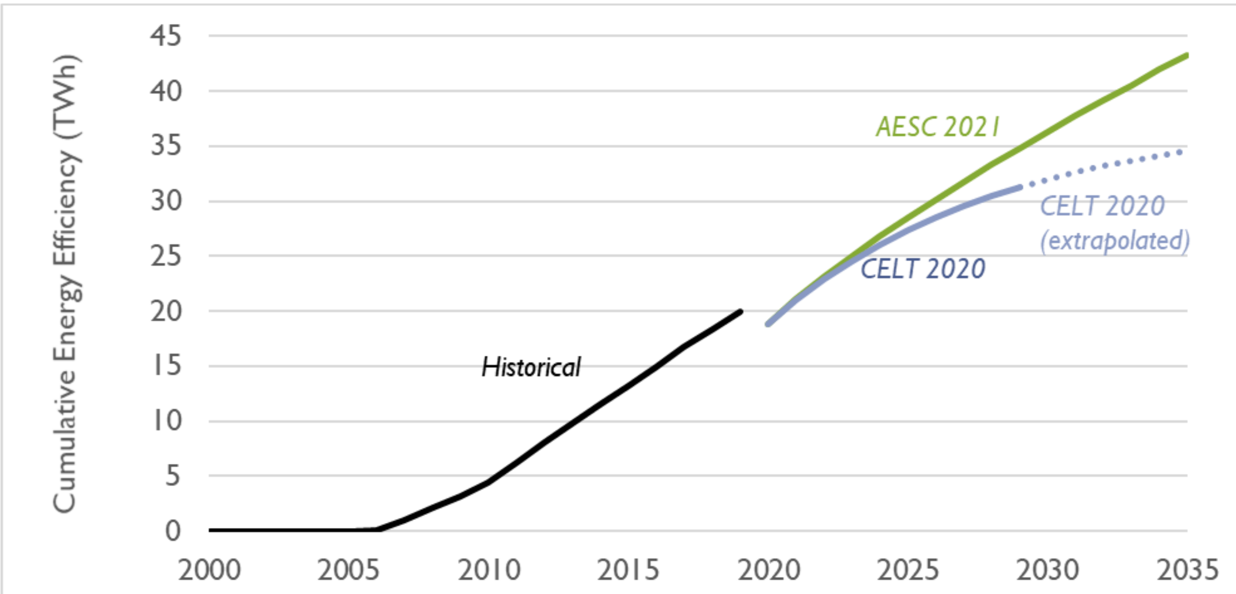
Depending on the climate policy sensitivity considered, we use a different counterfactual as a starting point. The No New EE Climate Policy Sensitivity relies on Counterfactual #3 as a starting point, whereas the All-In Climate Policy Sensitivity relies on Counterfactual #2 as a starting point. We make modifications to assumptions on energy efficiency, building electrification, transportation electrification, and active demand management.

<u>Energy efficiency</u>

In terms of energy efficiency assumptions, the No New EE Climate Policy Sensitivity does not differ from Counterfactual #3. Both series assume that no incremental energy efficiency is installed in 2021 or any later years.

The All-In Climate Policy Sensitivity uses the same energy efficiency assumptions as Counterfactual #2. Both modeling runs rely on a modified version of the energy efficiency forecast described in CELT 2020. This trajectory is illustrated in Figure 53 and discussed in detail above in Section 4.3: *New England system demand*. As in Counterfactual #2, hourly load profiles for energy efficiency match the load shape used in the econometric component of the energy forecast.

Figure 53. Historical and projected cumulative regionwide energy efficiency impacts used in the All-In Climate Policy Sensitivity



Notes: This is a reproduction of Figure 17. The All-In Climate Policy Sensitivity utilizes the "AESC 2021" trajectory for energy efficiency, which is the same assumption used in Counterfactual #2. No incremental energy efficiency installed in 2021 or any later year is modeled in the No New EE Climate Policy Sensitivity.

<u>Building electrification</u>

Both climate policy sensitivities envision a future with more ambitious building electrification policies than were modeled in the AESC 2021 counterfactuals. We note that Counterfactual #3 included some quantity of incremental building electrification (roughly 3.4 TWh regionwide by 2035, according to data produced by ISO New England in CELT 2020) while Counterfactual #2 maintained the level of building electrification identified in 2020 throughout the study period.

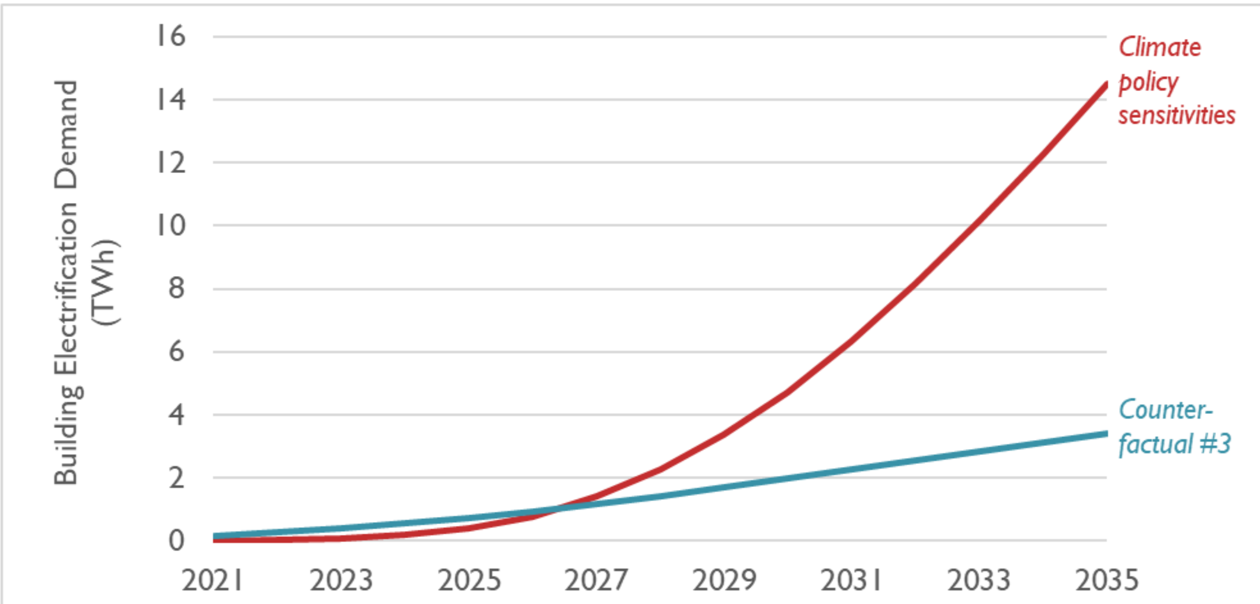
Both climate policy sensitivities use an entirely different projection for building electrification. We rely on inputs described in the December 2020 *Decarbonization Roadmap* study published by the Massachusetts Executive Office of Energy and Environmental Affairs (MA EEA).[334] This study envisions a

[334] A series of reports relevant to the *Decarbonization Roadmap* study can be found at https://www.mass.gov/info-details/ma-decarbonization-roadmap. Detail on building electrification measures can be found in *Building Sector Report: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study.* December 2020. Massachusetts Executive Office of Energy and Environmental Affairs. Available at https://www.mass.gov/doc/building-sector-technical-report/download.

number of different pathways in which all six New England states (as well as a number of other jurisdictions in the Northeast) achieve net-zero GHG emissions by 2050.

Specifically, we rely on building decarbonization data from the *Decarbonization Roadmap*'s "All Options" case. This case projects an increase in building electrification demand of about 14 TWh in 2035, relative to 2020 levels (see Figure 45).[335] This includes demand from both residential and commercial sectors, and it includes load related to space heating as well as water heating. We note that MA EEA's modeling is conducted through 2050; in 2050, MA EEA projects a total of 44 TWh related to building electrification throughout New England.[336]

Figure 54. Building electrification trajectory used in the climate policy sensitivities, compared with the trajectory used in Counterfactual #3



Note: No incremental building electrification measures installed in 2021 or any later year are modeled in Counterfactual #2.

As in Counterfactual #3 and other AESC 2021 counterfactuals, the hourly load profile assumed for building electrification in this sensitivity analysis relies on load shape data published by ISO New England in CELT 2020. See Section 4.3: *New England system demand* for more information.

[335] Detailed annual and state-specific data was provided to Synapse Team by MA EEA via email in January through March 2021. We note that at the time of AESC 2021's sensitivity analysis, MA EEA is continuing to model scenarios for its Interim Clean Energy and Climate Report for 2030 (more information is available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2030). Later scenarios discussed or published by MA EEA may explore different levels of building electrification than was used in this analysis.

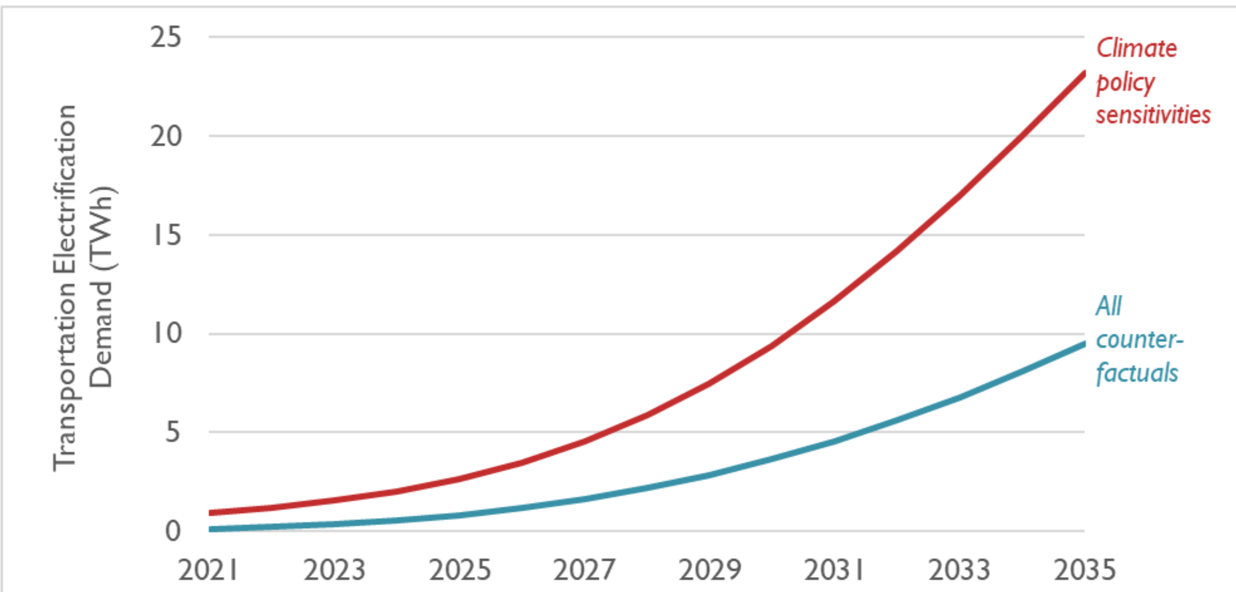
[336] As with all modeling in AESC 2021, our sensitivity analysis focuses on the years 2021 through 2035.

Transportation electrification

In all of the AESC counterfactuals, we rely on a forecast of transportation electrification demand based on Bloomberg New Energy Finance's (BNEF) *Electric Vehicle Outlook 2020*. By 2035, this projection results in 9.5 TWh of transportation electrification demand throughout New England. See Section 4.3: *New England system demand* for more information on how this projection was developed.

As with building electrification, the more ambitious trajectories for transportation electrification modeled in the AESC 2021 climate policy sensitivities are based on data from MA EEA's *Decarbonization Roadmap*. As with building electrification, we rely on annual, state-specific data for the "All Options" case, as provided to the Synapse Team by MA EEA. This projection includes demand from light-, medium-, and heavy-duty vehicles. This projection results in 23.2 TWh of transportation electrification demand throughout New England in 2035 (see Figure 55).

Figure 55. Transportation electrification trajectory used in the climate policy sensitivities, compared with the trajectory used in the AESC counterfactuals



Consistent with the AESC 2021 counterfactuals, the hourly load profile assumed for transportation electrification in this sensitivity analysis relies on load shape data published by ISO New England in CELT 2020. See Section 4.3: *New England system demand* for more information.

Flexible load

The the climate policy sensitivities feature exogenous flexible load resources not modeled in the main AESC counterfactuals. For the purposes of this section, flexible load is defined as the ability of some end-uses to shift the consumption of electricity from one hour to another. Examples of flexible load might include a program that requires, compensates, or requests EV owners to charge their vehicles at a later time, or for owners of electric water heaters to pre-heat their water several hours ahead of expected use.

The four main counterfactuals in AESC 2021 do not explicitly model any flexible load.[337] Instead, end-uses that are expected to allow for flexible load utilize simple, static hourly load shapes (see Section 4.3: *New England system demand* for more information on the assumed load shapes).

To determine an appropriate quantity of flexible load to model in our climate policy sensitivities, we relied upon the *Decarbonization Roadmap* study described above. Documentation for this study provides high-level information on the quantity of flexible load modeled in 2050 in Massachusetts for a number of different end-uses (including water heating, space heating, cooling, and light-duty vehicles).[338] In 2050, MA EEA models about 20 percent of Massachusetts' space and water heating demand being flexible (with a 1- or 2-hour advance or delay), and 50 percent of Massachusetts' LDV demand being flexible (with an 8-hour delay option only). We expand these percentages to the entire region (assuming that the rest of the region implements flexible load on a similar scale) and to years in the AESC 2021 Study Period (based on the modeled level of electrification in 2021 through 2035, relative to 2050). These calculations imply 600 MW of flexible load for space and water heating will be available regionwide in 2035, and 1,125 MW of flexible load for electric LDVs will be available in 2035. Figure 56 illustrates the quantities of flexible load that we modeled in each year. These quantities of flexible load were then assigned to each state based on each state's recent historical electricity demand relative to regionwide demand.

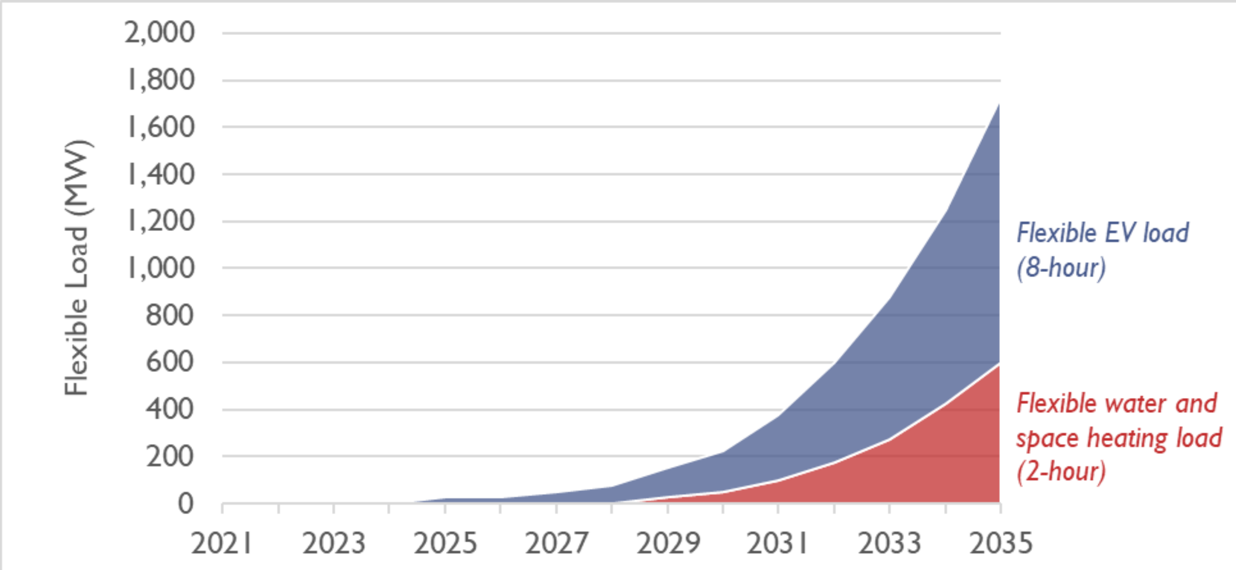
Flexible load is assumed to be eligible for capacity payments. We assume that, like other demand response resources, flexible load has a capacity credit of 90 percent (the same assumption used for battery storage). It is possible that in reality flexible load resources would require some other out-of-market payments or incentives. However, those costs are not modeled in this sensitivity analysis.[339]

[337] However, we note that all counterfactuals include some amount of active demand management, including demand response and behind-the-meter storage.

[338] Detail on flexible load is presented in Section 7.10 of MA EEAs' technical appendix titled *Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study*, available at https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

[339] This is consistent with how this analysis models costs related to building electrification and transportation electrification. Only costs related to existing electricity markets (e.g., energy, capacity RPS, and others) are modeled. Costs associated with other programs are not included.

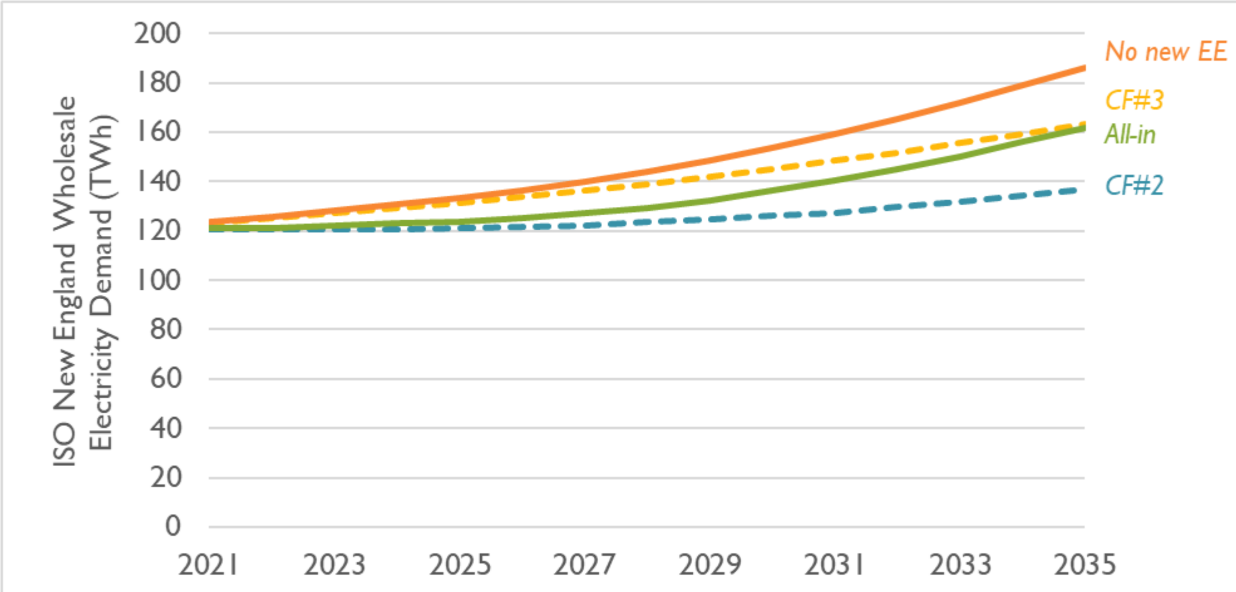
Figure 56. Proposed quantities of flexible load to be modeled in the climate policy sensitivities



Aggregate impacts

The demand-side policies described in the previous sections are combined with the econometric load forecast and produce the aggregate demand trajectories shown in Figure 57. Demand trajectories for Counterfactual #2 (CF#2) and Counterfactual #3 (CF#3) are shown for comparative purposes. We observe that systemwide demand in the All-In Climate Policy Sensitivity coincidently ends at roughly the same level as Counterfactual #3, although it follows a different trajectory (particularly during the mid- to late-2020s). Meanwhile, the No New EE Climate Policy Sensitivity closely resembles Counterfactual #3 through the mid-2020s before diverging and ending at a level roughly 23 TWh than Counterfactual #3 in 2035.

Figure 57. Systemwide wholesale demand in the No New EE and All-In Climate Policy Sensitivities



Modifications to supply

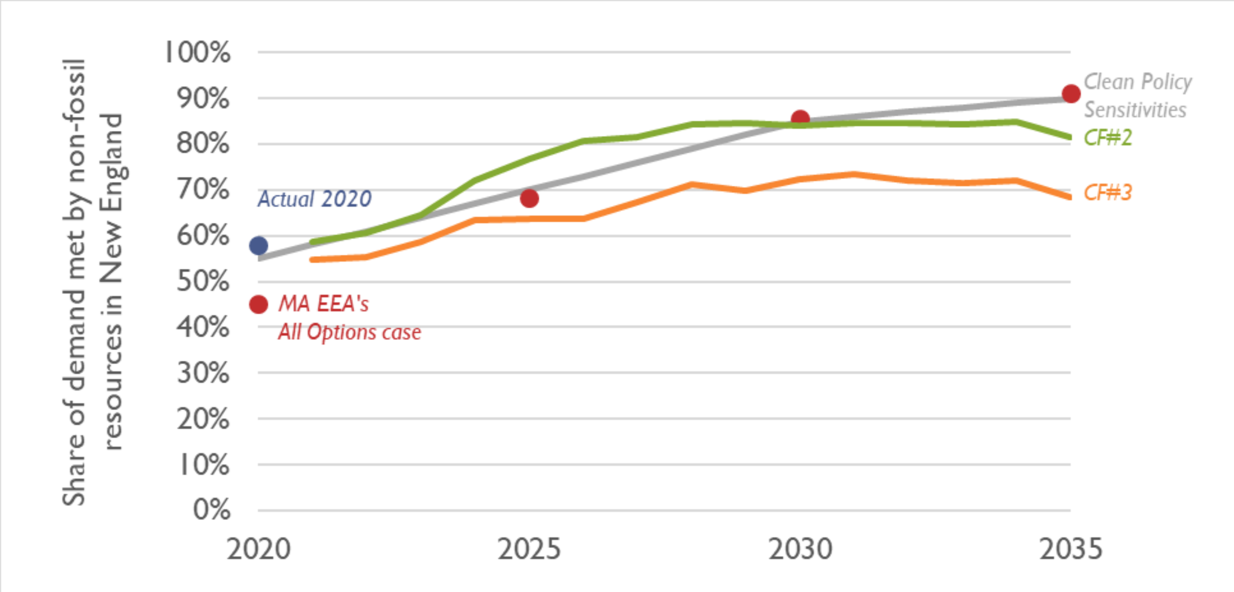
The climate policy sensitivities also envision changes to energy supply, beyond what is described elsewhere in this report. In short, we model an increasing amount of regional electricity demand being met with non-fossil resources. In our climate policy sensitivities, resources that are defined as "fossil" include resources where electricity is generated from burning coal, natural gas, or oil. All other resources are non-fossil, and include wind, solar, hydro, nuclear, biomass, imports, municipal solid waste, and other miscellaneous resource types.

To determine what level of incremental non-emitting supply should be modeled from 2021 through 2035, we return to the "All Options" case in MA EEA's *Decarbonization Roadmap*.[340] The "All Options" case achieves a non-emitting share of 68 percent in 2025, 84 percent in 2030, and 91 percent in 2035. Relying on this data, as well as actual data on the share of non-emitting supply in 2020 from ISO New England, the Synapse Team developed a clean policy trajectory from 2020 to 2035 (see Figure 58). This trajectory begins at 55 percent in 2020, reaches 70 percent in 2025, 85 percent in 2030, and finally 90 percent in 2035. Values in all other years are interpolated.

We do not model any additional renewable procurement policies beyond what is already modeled in the main AESC sensitivities. See Section 7.2 *Renewable Energy Certificate (REC) Price Forecasting* for more information on renewable procurement assumptions.

[340] Detailed annual and state-specific data was provided to Synapse Team by MA EEA via email in January through March 2021.

Figure 58. Shares of demand met by non-fossil resources in Counterfactual #2 (CF#2), Counterfactual #3 (CF#3), MA EEA's All Options Case, and the climate policy sensitivities



<u>Developing an incremental regional clean energy policy</u>

We multiply the clean policy trajectory (Figure 58) by the annual demand requirements (Figure 57) to estimate how much total non-fossil supply needs to be provided under the two climate policy sensitivities in each year. For both climate policy sensitivities, we then subtract the amount of non-fossil supply that is currently modeled in the "starting" counterfactuals (Counterfactual #3 for the No New EE Climate Policy Sensitivity and Counterfactual #2 for the All-In Climate Policy Sensitivity). This provides an initial estimate of how much more non-fossil supply is required to meet the clean policy trajectory. We then perform a series of steps to iterate on this TWh requirement:

- First, we model the policy as beginning in 2025. This is done because new renewable policies in New England frequently have a period between when they are codified and when they go into effect. This period allows the market to begin to respond to the policy and ramp up the production of new clean energy several years ahead of time.
- Second, we simplify the early years of the policy to allow for a gradual phase-in. Again, this is done to allow the clean energy market to respond to the policy and avoid non-compliance with or very high prices for the policy in the mid- to late-2020s.
- Third, we perform an interactive check to evaluate whether the clean policy trajectory described in Figure 58 is achieved.

We created the IRCEP to drive the deployment of this additional clean energy quantity. For the purposes of these sensitivities, the IRCEP has the following parameters:

- IRCEP functions like a new, additional RPS policy covering New England. Using the IRCEP requirements described above, the REMO model identifies which resources are most cost-effective for each sensitivity. Depending on the sensitivity and the year, we observe that these resources include onshore wind, utility-scale solar, and offshore wind.[341]

- IRCEP is a "wrap-around" policy, similar to the Massachusetts CES. To this end, all currently enacted RPS targets count toward satisfaction of the IRCEP. All incremental demand (above current RPS policies) is assumed fulfilled by Class I-eligible resources as defined by states with Class I RPS policies (e.g., Massachusetts, Connecticut, Rhode Island, Maine, and New Hampshire). In general, this includes land-based wind, offshore wind, solar, small hydro facilities meeting minimum sustainability criteria, and ocean energy systems. These resources may be built anywhere in New England or in adjacent control areas and have energy and RECs delivered to ISO New England.

- Unlike RPS policies, the IRCEP (as it is modeled here) does not include the flexibility to bank excess compliance in one year for application in a future year.

- Ordinarily, an RPS policy identifies entities who must legally comply with the policy. For example, in practice, Massachusetts load-serving entities (e.g., Eversource, National Grid, Until, and all competitive retail electricity providers) must retire a specific number of RECs to fulfill the Class 1 RPS requirement for each year. Because the IRCEP is a simplified, hypothetical, regionwide policy created to identify a shadow price of compliance with a climate policy, we do not specify the ultimate means of compliance.

<u>Other resource builds</u>

Unlike the main four counterfactuals in AESC 2021 and the High Gas Price Sensitivity, we disable the model's ability to build new natural gas-fired generators in the two climate policy sensitivities. This is done to align the sensitivities with a future in which 90 percent of electricity is supplied by non-fossil sources.[342]

However, the capacity expansion model is allowed to build energy storage resources. While energy storage is not a resource that will be built to fulfill IRCEP requirements, energy storage resources are available to be built if they are deemed economic. Reasons for economic builds might include reliability requirements for capacity (e.g., due to increased load associated with electrification) or low or negatively priced energy in some hours (e.g., as a result of a large supply of zero-marginal-cost renewables) and high-priced energy in other hours (e.g., when demand due in part to electrified end-uses is high, but supply from renewables is low). See Section 4.5: *Anticipated non-renewable resource additions and retirements* for more discussion on energy storage.

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[341] In particular, the cost of offshore wind is assumed to fall over time as later projects take advantage of transmission infrastructure constructed to serve earlier projects.

[342] We performed a number of exploratory runs examining outcomes with natural gas builds allowed. We observed largely consistent finding with the results described here, with similar energy and capacity prices.

Interpreting the resulting costs

IRCEP functions as an RPS policy across the six states. As with other RPS polices, it requires the purchase of RECs in order to comply, implying a cost of compliance.

For each state, we calculate costs resulting from the IRCEP as follows:

1. First, we calculate the total RPS percentage from new and existing programs, absent the IRCEP (see Table 55 and Table 56). In some states and years, this value is as low as 25 percent. In other states and years, this value is as high as 100 percent.
2. Second, we subtract the percentages calculated in Step 1 from the percentages associated with the clean energy trajectory. In some states and years, this calculation implies that 65 percent of statewide load is subject to IRCEP. In other states and years, this value is 0 percent. This percentage describes the amount of clean energy avoided by every 1 MWh of energy efficiency (e.g., a value of 65 percent means that for every 1 MWh of energy efficiency installed, 0.65 MWh of IRCEP-derived clean energy would be avoided).
3. Finally, we multiply the resulting percentages from Step 2 by the calculated cost of new entry for each year, for each state. This cost varies depending on which resources are marginal.

The resulting values would be the cost of compliance under IRCEP for each state. The above methodology is similar to the costs of RPS compliance calculations described in Section 7.3: *Avoided RPS compliance cost per MWh reduction.*

12.3. Results of sensitivity analysis

The following sections detail the results of the sensitivity analysis for energy prices, capacity prices, RPS compliance, and other avoided cost categories.

High Gas Price Sensitivity

This sensitivity is a modification of Counterfactual #1 using a higher natural gas price. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #1. A summary of the changes in avoided costs is shown in Table 131.

Table 131. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 High Gas Price Sensitivity versus AESC 2021 Counterfactual #1

	Counter-factual #1	High Gas Price Sensitivity	High Gas Price Sensitivity, relative to Counterfactual #1		Notes
	2021 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	1.18	1.15	-0.03	-2%	*3,4,5,6*
Avoided Retail Energy Costs	3.85	4.89	1.05	27%	*5,7,8*
Avoided RPS Compliance	1.28	1.17	-0.10	-8%	*5,7,9*
Subtotal: Capacity and Energy	**6.30**	**7.21**	**0.92**	**15%**	
GHG non-embedded	**4.74**	**3.75**	**-0.98**	**-21%**	*5,10*
NO_X non-embedded	**0.08**	**0.08**	**0.00**	**0%**	*5*
Transmission & Distribution (PTF)	**2.02**	**2.02**	**0.00**	**0%**	*3,5,11*
Value of Reliability	**0.01**	**0.01**	**0.00**	**0%**	*3,5,6,12*
Electric capacity DRIPE	0.41	0.41	0.00	0%	*5,6*
Electric energy and cross-DRIPE	1.20	1.39	0.19	16%	*5,7,13*
Subtotal: DRIPE	**1.61**	**1.80**	**0.19**	**12%**	**-**
Total	**14.77**	**14.89**	**0.12**	**1%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars.
2. All values shown in this figure relate to AESC 2021. AESC 2018 data is not presented in this table.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2021 Counterfactual #1 cost (2021 $/kW-year) of $49/kW-year
AESC 2021 High Gas Price Sensitivity cost (2021 $/kW-year) of $48/kW-year
5. Includes T&D loss adjustments of 9.0% for energy and 16.0% for peak demand
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh in Counterfactual #1 and $42/MWh in the High Gas Price Sensitivity
9. Avoided RPS compliance cost of $12/MWh in Counterfactual #1 and $11/MWh in the High Gas Price Sensitivity
10. Assumes non-embedded GHG cost based on New England MAC (electric sector)
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year in both cases. These values do not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year in Counterfactual #1 and $0.47/kW-year in the High Gas Price Sensitivity, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. These DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.

Energy prices

Table 132 compares the wholesale energy price results for this sensitivity with Counterfactual #1. As with the comparison described in Chapter 6: *Avoided Energy Costs*, all comparisons use 15-year levelized costs for WCMA reporting region. Generally, we find that the changes in levelized energy prices for this sensitivity correspond with the differences in Henry Hub prices described above.[343] As in Counterfactual #1, natural gas generators are the marginal resource in most hours of this sensitivity and typically set the price.

Table 132. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	$40.85	$46.86	$45.20	$32.67	$29.86
High Gas Price Sensitivity	$49.79	$55.80	$54.27	$41.57	$38.57
% Change	22%	19%	20%	27%	29%

Notes: Levelization period is 2021–2035 and real discount rate is 0.81 percent.

Capacity prices

Compared to Counterfactual #1, the 15-year levelized capacity price in the High Gas Price Sensitivity is 2 percent lower (see Table 133). This is because the two cases are identical from FCA 12 through FCA 24 (with no differences in resource builds or demand) with only minor differences in resource builds in 2034 and 2035 as a result of higher gas and energy prices.

[343] 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 133. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2021 Counterfactual #1	AESC 2021 High Gas Price Sensitivity
2021/2022	12	$4.77	$4.77
2022/2023	13	$3.96	$3.96
2023/2024	14	$2.47	$2.47
2024/2025	15	$2.75	$2.75
2025/2026	16	$2.72	$2.72
2026/2027	17	$2.88	$2.88
2027/2028	18	$3.11	$3.11
2028/2029	19	$3.30	$3.30
2029/2030	20	$3.59	$3.59
2030/2031	21	$3.42	$3.42
2031/2032	22	$3.67	$3.67
2032/2033	23	$3.90	$3.90
2033/2034	24	$3.86	$3.86
2034/2035	25	$4.67	$3.75
2035/2036	26	$3.66	$3.24
15-year levelized cost		**$3.51**	**$3.42**
Percent difference			**-2%**

Notes: Levelization period is 2021/2022 to 2035/2036 and real discount rate is 0.81 percent for AESC 2021. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Cost of RPS compliance

Table 134 shows how the cost of RPS compliance changes in the High Gas Price Sensitivity, relative to Counterfactual #1. Depending on the state and RPS class, costs of compliance in the High Gas Price Sensitivity are between 0 and 17 percent lower than in Counterfactual #1. Generally, higher gas prices yield lower costs of RPS compliance, as the renewables built to fulfill these RPS requirements are able to obtain a larger amount of revenue from the energy market. As a result, they require less in the way of additional costs from the sale of RECs, which lowers the cost of RPS compliance.

Table 134. Avoided cost of RPS compliance (2021 $ per MWh)

		CT	ME	MA	NH	RI	VT
Counterfactual #1	Class 1/New	$6.59	$6.92	$5.61	$2.66	$14.96	$1.34
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$2.05	$5.44	$0.03	$2.56
	Total	**$7.93**	**$7.37**	**$11.81**	**$8.10**	**$14.99**	**$3.90**
High Gas Price Sensitivity	Class 1/New	$5.65	$5.73	$4.76	$2.35	$12.50	$1.15
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$1.96	$5.39	$0.03	$2.33
	Total	**$6.99**	**$6.18**	**$10.86**	**$7.74**	**$12.53**	**$3.47**
Percent Difference	Class 1/New	-14%	-17%	-15%	-11%	-16%	-14%
	MA CES & CPS	-	-	0%	-	-	-
	All Other Classes	0%	0%	-4%	-1%	16%	-9%
	Total	**-12%**	**-16%**	**-8%**	**-4%**	**-16%**	**-11%**

Other avoided costs

We observe minor differences in other avoided cost categories. Relative to Counterfactual #1, avoided costs for PTF, NO_X non-embedded, and capacity DRIPE in the High Gas Price Sensitivity are either identical or nearly so. We observe higher energy and cross-DRIPE values as a result of higher energy prices. Finally, we observe that the GHG non-embedded cost is about 20 percent lower than in Counterfactual #1. This is because when this value is based on a New England-based marginal abatement cost, one of the inputs to this value is energy prices. Higher energy prices imply a smaller residual cost for the marginal resource (in this case, offshore wind), causing the compliance cost to decrease.

No New EE Climate Policy Sensitivity

This sensitivity is a modification of Counterfactual #3 with higher loads and more clean energy. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #3. A summary of the changes in avoided costs is shown in Table 135. This table differs from similar versions of this table found throughout this report in that it includes a separate line for avoided costs related to IRCEP compliance. It also differs from other versions in that the “GHG non-embedded” row in Table 135 utilizes the social cost of carbon, rather than the marginal abatement cost derived from the New England electricity sector. This is because in some ways, the entire sensitivity is a marginal abatement cost calculation. As a result, we do not provide this comparison in the report in order to avoid improper comparisons and applications. See the subsection at the end of this chapter titled “Other considerations for modeling climate policy sensitivities” for more discussion on this topic.

Table 135. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 No New EE Climate Policy Sensitivity versus AESC 2021 Counterfactual #3, using the SCC

	Counter-factual #3	No New EE Climate Policy Sensitivity	No New EE Climate Policy Sensitivity, relative to Counterfactual #3		*Notes*
	2021 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	1.22	1.86	0.64	52%	*3,4,5,6*
Avoided Retail Energy Costs	3.92	3.79	-0.12	-3%	*5,7,8*
Avoided RPS Compliance	1.40	1.56	0.17	12%	*5,7,9*
Avoided IRCEP Costs	-	0.15	-	-	*14*
Subtotal: Capacity and Energy	**6.54**	**7.37**	**0.83**	**13%**	
GHG non-embedded (based on SCC)	**4.87**	**4.87**	**0.00**	**0%**	*5,10*
NO_X non-embedded	**0.08**	**0.08**	**0.00**	**0%**	*5*
Transmission & Distribution (PTF)	**2.02**	**2.02**	**0.00**	**0%**	*3,5,11*
Value of Reliability	**0.01**	**0.01**	**0.00**	**0%**	*3,5,6,12*
Electric capacity DRIPE	0.41	0.41	0.00	0%	*5,6*
Electric energy and cross-DRIPE	1.21	1.20	-0.01	-1%	*5,7,13*
Subtotal: DRIPE	**1.62**	**1.61**	**-0.01**	**-1%**	**-**
Total	**15.15**	**15.96**	**0.81**	**5%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars.
2. All values shown in this figure relate to AESC 2021. AESC 2018 data is not presented in this table.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2021 Counterfactual #3 cost (2021 $/kW-year) of $51/kW-year
AESC 2021 No new EE climate policy sensitivity cost (2021 $/kW-year) of $79/kW-year
5. Includes T&D loss adjustments of 9.0% for energy and 16.0% for peak demand
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $33/MWh in Counterfactual #3 and $32/MWh in the No New EE Climate Policy Sensitivity
9. Avoided RPS compliance cost of $13/MWh in Counterfactual #3 and $16/MWh in the No New EE Climate Policy Sensitivity
10. Assumes non-embedded GHG cost based on the social cost of carbon in both cases
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year in both cases. These values do not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.47/kW-year in Counterfactual #3 and $0.47/kW-year in the No New EE Climate Policy Sensitivity, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. These DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
14. The IRCEP cost represents this state's incremental cost of deploying enough clean energy for the region to reach 90 percent clean energy by 2035.

Energy prices

Table 136 compares the wholesale energy price results for this sensitivity with Counterfactual #3. As with the comparison described in Chapter 6: *Avoided Energy Costs*, all comparisons use 15-year levelized costs for WCMA reporting region. Generally, we find that prices are 4 percent lower than estimated in Counterfactual #3. This is largely due to zero-marginal-cost renewables lowering the clearing price. However, as in Counterfactual #3, natural gas generators are the marginal resource in most hours and typically set the price.

Table 136. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 3	$41.34	$47.43	$45.63	$33.28	$29.93
No New EE Climate Policy Sensitivity	$39.82	$46.20	$43.62	$32.23	$28.02
% Change	-4%	-3%	-4%	-3%	-6%

Notes: Levelization period is 2021–2035 and real discount rate 0.81 percent.

Capacity prices

Compared to Counterfactual #3, the 15-year levelized capacity price in the No New EE Climate Policy Sensitivity is 55 percent higher (see Table 137 and Figure 59). Capacity price trajectories are similar until FCA 22, at which point the two series diverge. Capacity prices in the No New EE Climate Policy Sensitivity increase, nearing or reaching the price ceiling implied by the MRI curve in FCA 24 through FCA 26. This price increase is due to a rapid increase in peak demand due to electrification, particularly in FCA 24 through FCA 26 when the system switches to winter peaking.

To model capacity prices in winter peaking years, we follow an identical methodology described above in Chapter 5: *Avoided Capacity Costs*, with two exceptions: (1) we rely on winter peak values to inform the demand quantity and (2) we adjust the capacity contribution for solar and wind to reflect more accurate seasonal capacity contributions from these resources.[344] Otherwise, we assume that the market's operation is unchanged. Likewise, other results that are derived from the capacity price modeling (e.g., capacity DRIPE, reliability) are derived using identical methodologies to that described in previous chapters.

We note that the operation of the capacity market in a winter-peaking future is highly uncertain. However, given what we know about the structure of the market as it exists today, the above changes are the only necessary modifications to successfully model a capacity price.

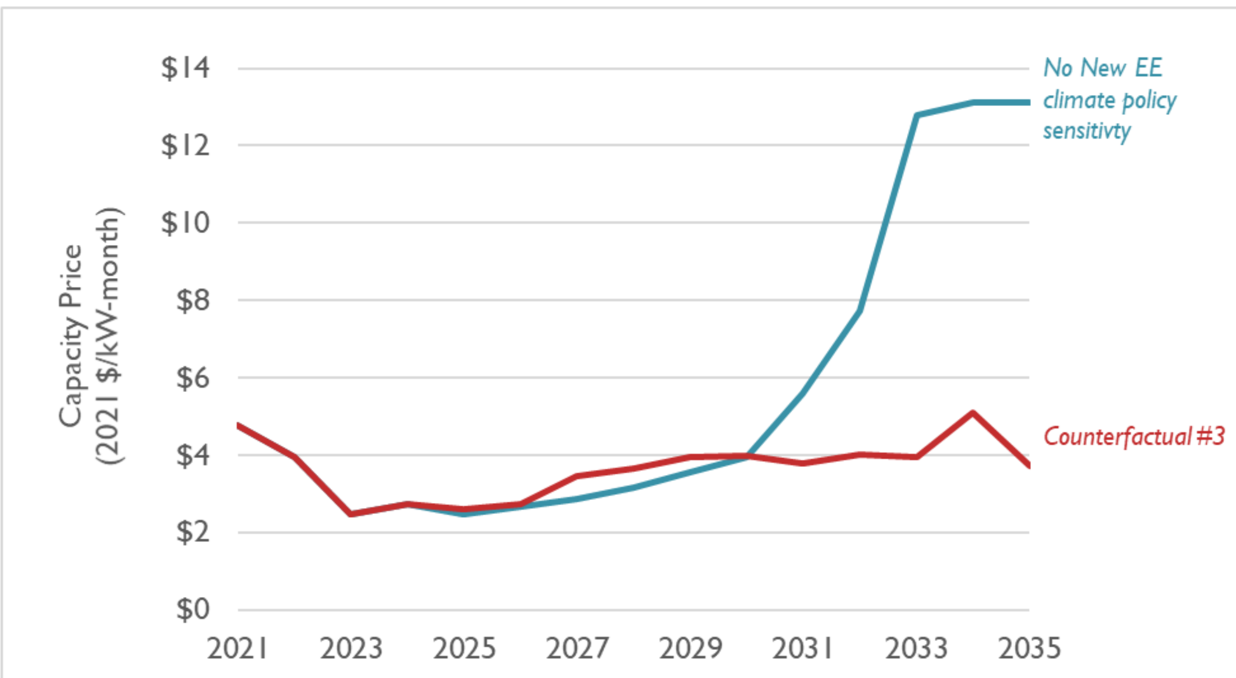
[344] Based on historical data from ISO New England on capacity obligations (see FCA Obligations workbook at https://www.iso-ne.com/static-assets/documents/2018/02/fca_obligations.xlsx) we assume that the winter capacity contribution of wind is double the summer capacity contribution, and that the winter capacity contribution of solar is 0 percent.

Table 137. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2021 Counterfactual #3	No New EE Climate Policy Sensitivity
2021/2022	12	$4.77	$4.77
2022/2023	13	$3.96	$3.96
2023/2024	14	$2.47	$2.47
2024/2025	15	$2.75	$2.75
2025/2026	16	$2.59	$2.46
2026/2027	17	$2.75	$2.66
2027/2028	18	$3.46	$2.86
2028/2029	19	$3.65	$3.15
2029/2030	20	$3.94	$3.57
2030/2031	21	$3.97	$3.95
2031/2032	22	$3.79	$5.59
2032/2033	23	$4.02	$7.73
2033/2034	24	$3.95	$12.80
2034/2035	25	$5.09	$13.13
2035/2036	26	$3.73	$13.13
15-year levelized cost		**$3.65**	**$5.56**
Percent difference			**52%**

Notes: Levelization period is 2021/2022 to 2035/2036 and real discount rate is 0.81 percent for AESC 2021. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Figure 59. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)



Cost of RPS compliance

Table 138 shows how the cost of RPS compliance changes in the No New EE Climate Policy Sensitivity, relative to Counterfactual #3. Depending on the state and RPS class, costs of compliance in the No New EE Climate Policy Sensitivity are between 0 and 30 percent higher than in Counterfactual #3. This increase in compliance costs is due to increased energy demand, and as a result, increased REC prices and resulting RPS compliance costs.

Table 138. Avoided cost of RPS compliance (2021 $ per MWh)

		CT	ME	MA	NH	RI	VT
Counterfactual #3	Class 1/New	$7.50	$8.11	$6.66	$3.18	$16.77	$1.58
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$2.13	$5.49	$0.03	$2.86
	Total	**$8.84**	**$8.56**	**$12.93**	**$8.67**	**$16.81**	**$4.44**
No New EE Climate Policy Sensitivity	Class 1/New	$8.82	$10.55	$8.15	$4.07	$21.61	$1.92
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$2.17	$5.54	$0.03	$3.23
	Total	**$10.16**	**$11.00**	**$14.47**	**$9.62**	**$21.64**	**$5.15**
Percent Difference	Class 1/New	18%	30%	22%	28%	29%	22%
	MA CES & CPS	-	-	0%	-	-	-
	All Other Classes	0%	0%	2%	1%	16%	13%
	Total	**15%**	**28%**	**12%**	**11%**	**29%**	**16%**

Other avoided costs

We observe minor differences in other avoided cost categories. Relative to Counterfactual #3, avoided costs for PTF, NO_X non-embedded, capacity DRIPE, energy DRIPE and cross-DRIPE in the No New EE Climate Policy Sensitivity are either identical or nearly so.

All-In Climate Policy Sensitivity

This sensitivity is a modification of Counterfactual #2 with higher loads and more clean energy. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #2. A summary of the changes in avoided costs is shown in Table 139. This table differs from similar versions of this table found throughout this report in that it includes a separate line for avoided costs related to IRCEP compliance. It also differs from other versions in that the "GHG non-embedded" row in Table 135Table 139 utilizes the social cost of carbon, rather than the marginal abatement cost derived from the New England electricity sector. This is because in some ways, the entire sensitivity is a marginal abatement cost calculation. As a result, we do not provide this comparison in the report in order to avoid improper comparisons and applications. See the subsection at the end of this chapter titled "Other considerations for modeling climate policy sensitivities" for more discussion on this topic.

Table 139. Illustration of avoided retail summer on-peak electricity cost components, AESC 2021 All-In Climate Policy Sensitivity versus AESC 2021 Counterfactual #2, using the SCC

	Counter-factual #2	All-In Climate Policy Sensitivity	All-In Climate Policy Sensitivity, relative to Counterfactual #2		*Notes*
	2021 cents/kWh	*2021 cents/kWh*	*2021 cents/kWh*	*% Difference*	
Avoided Retail Capacity Costs	1.16	1.64	0.48	42%	*3,4,5,6*
Avoided Retail Energy Costs	3.63	3.49	-0.14	-4%	*5,7,8*
Avoided RPS Compliance	0.98	1.08	0.11	11%	*5,7,9*
Avoided IRCEP Costs	-	0.06	-	-	*14*
Subtotal: Capacity and Energy	**5.77**	**6.28**	**0.51**	**9%**	
GHG non-embedded (based on SCC)	**4.87**	**4.87**	**0.00**	**0%**	*5,10*
NO_X non-embedded	**0.08**	**0.08**	**0.00**	**0%**	*5*
Transmission & Distribution (PTF)	**2.02**	**2.02**	**0.00**	**0%**	*3,5,11*
Value of Reliability	**0.01**	**0.01**	**0.00**	**-1%**	*3,5,6,12*
Electric capacity DRIPE	0.39	0.39	0.00	0%	*5,6*
Electric energy and cross-DRIPE	1.08	1.10	0.02	2%	*5,7,13*
Subtotal: DRIPE	**1.47**	**1.48**	**0.02**	**1%**	**-**
Total	**14.22**	**14.75**	**0.53**	**4%**	**-**

Notes:
1. Values are shown for the WCMA reporting zone, summer on-peak, on a 15-year levelized basis; all values are in 2021 dollars.
2. All values shown in this figure relate to AESC 2021. AESC 2018 data is not presented in this table.
3. Assumes load factor of 55%
4. Avoided cost of capacity purchases:
AESC 2021 Counterfactual #2 cost (2021 $/kW-year) of $48/kW-year
AESC 2021 All-in climate policy sensitivity cost (2021 $/kW-year) of $68/kW-year
5. Includes T&D loss adjustments of 9.0% for energy and 16.0% for peak demand
6. This table assumes that 100% of capacity, capacity DRIPE, and reliability values are cleared or bid into the capacity market
7. Includes wholesale risk premium adjustment of 8.0%
8. Avoided wholesale energy cost (2021 $/MWh) of $31/MWh in Counterfactual #2 and $29/MWh in the All-In Climate Policy Sensitivity
9. Avoided RPS compliance cost of $9/MWh in Counterfactual #2 and $10/MWh in the All-In Climate Policy Sensitivity
10. Assumes non-embedded GHG cost based on social cost of carbon in both cases
11. Assumes pooled transmission facility (PTF) cost (2021 $/kW-year) of $84/kW-year in both cases. These values do not include avoided costs related to non-PTF facilities or local T&D systems.
12. Assumes reliability value (2021 $/kW-year) of $0.46/kW-year in Counterfactual #2 and $0.45/kW-year in the High Gas Price Sensitivity, and a VOLL of $73/kWh
13. "Electric energy and cross-DRIPE" is the sum of electric energy, G-E cross-DRIPE and E-G-E cross-DRIPE. These DRIPE values represent the Massachusetts-wide (zone-on-zone) value, but not the Rest-of-Pool amount.
14. The IRCEP cost represents this state's incremental cost of deploying enough clean energy for the region to reach 90 percent clean energy by 2035.

Energy prices

Table 140 compares the wholesale energy price results for this sensitivity with Counterfactual #2. As with the comparison described in Chapter 6: *Avoided Energy Costs*, all comparisons use 15-year levelized costs for WCMA reporting region. Generally, we find that prices are 3 percent higher than estimated in Counterfactual #2. Price increases due to higher loads are largely offset by price decreases due to zero-marginal-cost renewables lowering the clearing price. Winter prices increase as a result of higher winter loads caused by building and transportation electrification.

Table 140. Comparison of energy prices for WCMA region (2021 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 2	$37.79	$42.98	$41.66	$30.87	$27.95
All-In Climate Policy Sensitivity	$38.87	$45.70	$43.27	$29.64	$26.63
% Change	3%	6%	4%	-4%	-5%

Notes: Levelization period is 2021–2035 and real discount rate is 0.81 percent.

Capacity prices

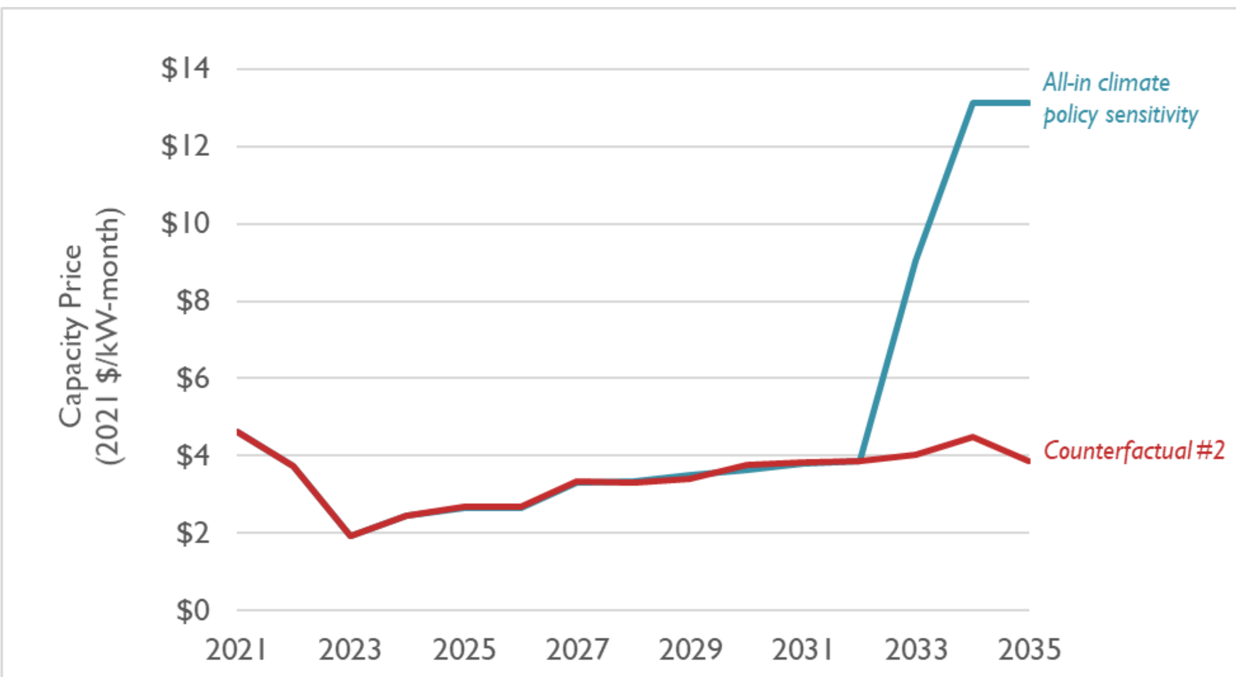
Compared to Counterfactual #2, the 15-year levelized capacity price in the All-In Climate Policy Sensitivity is 42 percent higher (see Table 141 and Figure 60). Capacity prices in the All-In Climate Policy Sensitivity are identical or similar to prices in Counterfactual #2 from FCA 12 through FCA 23, as more clean energy comes online and demand does not diverge substantially. Beginning in FCA 24, the All-In Climate Policy Sensitivity features a faster increase in demand, caused by increased electrification and a switch to winter peaking, resulting in higher prices. See the above section on capacity price results for the No New EE Climate Policy Sensitivity for more information on how capacity price modeling was performed for these winter-peaking years.

Table 141. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2021 Counterfactual #2	AESC 2021 All-In Climate Policy Sensitivity
2021/2022	12	$4.63	$4.63
2022/2023	13	$3.73	$3.73
2023/2024	14	$1.92	$1.92
2024/2025	15	$2.46	$2.46
2025/2026	16	$2.69	$2.64
2026/2027	17	$2.69	$2.65
2027/2028	18	$3.33	$3.29
2028/2029	19	$3.30	$3.33
2029/2030	20	$3.41	$3.49
2030/2031	21	$3.77	$3.62
2031/2032	22	$3.81	$3.79
2032/2033	23	$3.86	$3.87
2033/2034	24	$4.02	$9.04
2034/2035	25	$4.47	$13.13
2035/2036	26	$3.86	$13.13
15-year levelized cost		**$3.45**	**$4.89**
Percent difference			**42%**

Notes: Levelization period is 2021/2022 to 2035/2036 and real discount rate is 0.81 percent for AESC 2021. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2021 User Interface.

Figure 60. Comparison of capacity prices in rest-of-pool (2021 $ per kW-month)



Cost of RPS compliance

Table 142 shows how the cost of RPS compliance changes in the All-In Climate Policy Sensitivity, relative to Counterfactual #2. Depending on the state and RPS class, costs of compliance in the All-In Climate

Policy Sensitivity are between 0 and 60 percent higher than in Counterfactual #2. This increase in compliance costs is due to increased energy demand, and as a result, increased REC prices and resulting RPS compliance costs.

Table 142. Avoided cost of RPS compliance (2021 $ per MWh)

		CT	ME	MA	NH	RI	VT
Counterfactual #2	Class 1/New	v	$3.10	$3.10	$1.31	$5.63	$0.75
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$1.80	$5.11	$0.03	$1.93
	Total	**$4.77**	**$3.55**	**$9.04**	**$6.41**	**$5.66**	**$2.67**
All-In Climate Policy Sensitivity	Class 1/New	$4.78	$4.67	$3.95	$1.69	$9.02	$0.95
	MA CES & CPS	-	-	$4.14	-	-	-
	All Other Classes	$1.34	$0.45	$1.92	$5.22	$0.03	$2.16
	Total	**$6.12**	**$5.12**	**$10.01**	**$6.91**	**$9.05**	**$3.11**
Percent Difference	Class 1/New	39%	51%	27%	29%	60%	26%
	MA CES & CPS	-	-	0%	-	-	-
	All Other Classes	0%	0%	6%	2%	16%	12%
	Total	**28%**	**44%**	**11%**	**8%**	**60%**	**16%**

Other avoided costs

We observe minor differences in other avoided cost categories. Relative to Counterfactual #2, avoided costs for PTF, NO_X non-embedded, capacity DRIPE, energy DRIPE and cross-DRIPE in the No New EE Climate Policy Sensitivity are either identical or nearly so.

As in the No New EE Climate Policy Sensitivity, we observe large differences between the IRCEP cost and the non-embedded GHG cost based on the marginal abatement cost from the New England electric sector. Compared to the No New EE Climate Policy Sensitivity, non-embedded GHG costs in this sensitivity are lower primarily as a result of lower loads. In this sensitivity, IRCEP drives the addition of only a small amount of incremental renewable capacity before 2029. This produces low costs of compliance in the early years of the study, which are the least-discounted and therefore the most valuable from a levelized perspective.

For more information on why costs under IRCEP differ from costs derived from a New England-derived MAC, see page 313.

Other considerations for modeling climate policy sensitivities

This section focuses on other considerations related to the climate policy sensitivities. These considerations may be useful when developing future AESC analyses.

Energy prices

Except in a few situations described above, we note that energy prices in the climate policy sensitivities closely resemble energy prices in the main counterfactuals. In other words, adding a substantial amount of clean energy to the grid (even above the quantity expected under current legislation and regulations) and increasing electric demand by nearly 20 percent does not substantially change energy prices on annual basis. However, we do note that there are seasonal shifts. In particular, we observe lower summer prices (as more solar depresses energy prices during periods of high insolation) and higher winter prices (as higher levels of building and transportation electrification drive an increased demand for electricity in winter months). As electrification levels continue to increase past 2035, it is possible that we may observe larger changes in energy prices.

In addition, in the No New EE Climate Policy Sensitivity, we observe very low energy prices from the mid-2020s through the early 2030s in Maine. This is caused by a large amount of onshore wind deployments, without corresponding increases in transmission (to link Maine with southern New England) or increased loads in Maine itself (e.g., accelerating deployments of EVs or heat pumps). Future AESC modeling may wish to take these constraints into consideration, as the assumptions used for transmission or load changes may have a substantial impact on energy prices.

Electric sector generation

We observe that implementing the climate policies described above implies that generation from fossil-fired power plants decreases from about 50 TWh in 2020, to about 30 TWh in 2025 to about 20 TWh in 2028 through 2035.

We also note that in years with very high levels of renewables (e.g., the mid-2030s), the model is not always able to reach the IRCEP requirement. For example, in the All-In Climate Policy Sensitivity, we reached 87 percent non-fossil energy in 2035, rather than the 90 percent target. This discrepancy is partly due to wind curtailments and increasing storage demand, as well as non-fossil resources (like nuclear and hydro) being unexpectedly displaced by renewable resources. This observation may in some instances be a modeling artifact, caused by inconsistencies in input assumptions related to weather patterns for renewables and load. In future AESC studies, it may behoove the Study Group to evaluate this phenomenon in more detail.

Finally, the current climate policy sensitivities attribute existing non-emitting generation among the six states at a very high level. As states increasingly deploy polices (like Massachusetts' CES-E or municipal GGES) that require load-serving entities to procure and retire clean energy certificates, this may cause a shift in the IRCEP compliance cost across the states.

Capacity prices and winter peak

In both climate policy sensitivities, we observe that the New England electricity system becomes winter peaking in the early 2030s. This change to winter peaking may necessitate substantive changes to the design of the current capacity market. In the interim, the capacity prices calculated in this analysis represent our best estimate of capacity prices under the current construct. We do modify seasonal capacity credits for solar and wind, which substantially reduces available supply.

Climate policy sensitivity results and marginal abatement costs

Generally speaking, we observe large differences between the IRCEP cost and the non-embedded GHG cost based on the marginal abatement cost from the New England electric sector (e.g., offshore wind). We note that these approaches represent fundamentally different approaches to calculating the cost of abating climate pollution.

- The New England-specific marginal abatement cost derived from the electric sector is equal to the all-in cost of offshore wind, less energy costs. This cost starts immediately in 2021 at a high price, then decreases over time.
- In the climate policy sensitivity, we begin modeling the IRCEP program beginning in 2025. This means there is no cost in the first four years of the study. Over time, this policy results in dozens of TWh of additional clean energy added to the New England system. This incremental clean energy consists of a mix of solar, onshore wind, and offshore wind.

Because of the different approaches used to create these values, results from these two approaches are challenging to compare on an apples-to-apples basis. Some of the major differences include:

- The New England marginal abatement cost approach assumes that avoided costs begin in 2021 and persist throughout the study period. In the climate policy sensitivities, the IRCEP program begins in 2025. This difference is key when comparing costs in levelized terms. Because of the levelization calculations used in summarizing avoided costs in AESC, where values earlier in the analysis are discounted less than values far into the study period, there are at least four “high-worth” near-term years in the climate policy sensitivities where the cost of compliance is $0 per MWh.
- In the climate policy sensitivities, we derate the cost of new entry by each state’s share of load that is subject to the IRCEP. For example, in Massachusetts in 2035, we calculate that 86 percent of EDC load is subject to the RPS or similar programs. Because the regional target in this year under IRCEP is 90 percent, we would multiply the cost of new entry by 4 percent. In another example, in Rhode Island in 2035, 100 percent of load is expected to be met with current RPS programs. This means that there is no incremental cost associated with IRCEP, and therefore the compliance cost is zero. In the New England MAC approach, the compliance cost is not derated.
- The cost of new entry differs in the two approaches. In the New England MAC approach, the cost of new entry is based on offshore wind, which has a high cost early in the period that decreases over time. Meanwhile, in the climate policy sensitivities, the cost of new entry is based on a mix of different resources, including solar, onshore wind, and offshore wind.

Separately, we note that the non-embedded GHG cost under IRCEP is also substantially lower than the social cost of carbon recommended in Chapter 8: *Non-Embedded Environmental Costs*. These represent two fundamentally different approaches to calculating the non-embedded GHG cost. (the social cost of carbon is a damage approach, while IRCEP is a marginal abatement cost approach).

Considering costs after 2035

The climate policy sensitivities are modeled in detail from 2021 through 2035, consistent with the detailed modeling horizon used elsewhere in AESC. This limitation means that costs reported in the period after 2035 are extrapolated based on costs from 2031-2035. In years after 2035, electricity markets will likely face a number of new issues that may lead to substantially different avoided costs than are reported with this extrapolation technique.

- In order for the New England states to reach their climate and decarbonization goals, we expect that that levels of building and transportation electrification are likely to increase substantially after 2035. For example, in the All-in climate policy sensitivity, regional loads in 2035 are projected to be 1.3 times higher than today. Massachusetts' *Decarbonization Roadmap* study suggests that electrification would cause 2040 loads to be 1.5 times higher than today. In 2050, loads would be 1.9 times higher. These higher levels of load may lead to increased energy and capacity prices.

- Higher levels of load would also likely increase RPS compliance and IRCEP compliance costs, all else being equal. IRCEP costs may also increase as a result of clean energy requirements increasing 90 percent (e.g., 100 percent by 2050, as is assumed in the *Decarbonization Roadmap* study). The subsection above titled "Electric sector generation" discusses in more detail the challenges of modeling an electricity system with very high levels of renewable penetration, and the impacts on avoided costs associated with these challenges.

- Reaching very high levels of renewable penetration (e.g., 85-100 percent) and electrification may require other investments not currently addressed in the AESC study. For example, this future may involve high levels of investment in transmission and distribution, increased needs for flexible load and long-duration storage, or novel technologies for smaller, hard-to-reach sectors not considered in these sensitivities (e.g., hydrogen or renewable fuels).

- Because capacity costs rise quickly in the early 2030s, the extrapolation techniques used for calculating avoided costs in 2036-2055 for the main AESC analysis yield implausibly high capacity costs in these years.

Other climate policy costs

The costs analyzed in this chapter are primarily focused on electric sector costs. Our analysis does not include any costs or prices associated with building electrification, transportation electrification, or energy efficiency deployment. Our modeled costs in this chapter also do not include any avoided costs related to renewable fuels (like RNG or B100), which may be useful to consider as a complementary avoided cost for building electrification measures alongside the IRCEP price described here.

Finally, our analysis does not include any costs of distribution investments or enhancements, which may be necessary in some areas as building and transportation electrification increases, or, conversely, mitigated by energy efficiency under these same circumstances. The avoided costs associated with this mitigation may be substantial and are not included in our avoided cost calculations.

APPENDIX A: USAGE INSTRUCTIONS

This appendix describes how values post-2035 are extrapolated, 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.

Extrapolation of values post-2035

Many demand-side measures have lifetimes extending past 2035, which requires the extrapolation of avoided cost values for years 2036 through 2055.[345]

In past editions of AESC, authors used the formula as described in Equation 12 to extrapolate costs for each avoided cost category.[346] The resulting growth rate is then applied to values in 2035 to calculate values in 2036. Subsequent years through 2055 are calculated similarly.

Equation 12. Compound annual growth rate (CAGR) formula used in past versions of AESC

$$CAGR = \left(\frac{Avoided\ Cost_{n+4}}{Avoided\ Cost_n}\right)^{\left(\frac{1}{4}\right)} - 1$$

This extrapolation methodology was chosen historically because it relies on values that are "close to" the extrapolated period, under the theory that extrapolated values would be most influenced by more "recent" values (and should be less influenced by values in the early 2020s, for example). However, members of the AESC 2021 Study Group pointed out that because this methodology only relies on two data points, in certain circumstances (i.e., when the 2031 or 2035 values are divergent relative to the rest of the series) this method can produce a very high or very low growth rate. As a result, it may not be suitable for calculating avoided costs post-2035.

The Synapse Team developed a list of pros and cons of the CAGR extrapolation methodology as well as other methodologies, then provided a recommendation for which approach to use.

Compound annual growth rate (CAGR)

A CAGR spanning a five-year period has been the method used for extrapolating non-modeled values in all recent previous AESC studies. But other CAGR periods (e.g., spanning 6 years, 10 years, or something

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[345] Program administrators installing measures with long lifetimes in 2022 or later years will utilize avoided costs in 2051 and later.

[346] In past versions of AESC, this has been referred to this as a "Five-year CAGR" since it spans five data years, although it only covers four years of growth.

else) are also possible candidates for use. Table 143 summarizes the main advantages and disadvantages of the CAGR approach.

Table 143. Advantages and disadvantages of CAGR approach

Advantages	Disadvantages
A shorter-term CAGR relies on data points that are closest to the extrapolated period.	Any CAGR relies on two data points. If these data points are outliers relative to the rest of the series, the growth rate may be too low or too high.
This approach has been used historically and is widely recognized and understood.	

Average annual growth rate (AAGR)

The AAGR is a common alternate to the CAGR. AAGR is calculated by determining the annual year-on-year change in the values of a series, then calculating the simple mathematical mean (average) over that set of resulting growth rates. Unlike CAGR, it relies on a set of numbers to inform future values (rather than only two data points). However, AAGR has a drawback of overstating trends in some circumstances. Consider the example shown in Table 144. In this scenario, the series varies between a value of 100 and 110 over a period of 11 years, but returns to 100 in the final year. Because a unit reduction from a high value is a lower percentage than a unit reduction from a low value, the AAGR is 0.5 percent over this time period, whereas a CAGR would produce a growth rate of 0 percent. If annual variability is small, this effect may not substantially bias the resulting AAGR. However, if the annual variability is large in at least some years, the resulting AAGR may be larger than expected.

Table 144. Example of AAGR calculation over a stationary series

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Value	100	110	100	110	100	110	100	110	100	110	100
Annual Growth rate	-	10%	-9%	10%	-9%	10%	-9%	10%	-9%	10%	-9%
AAGR	-	-	-	-	-	-	-	-	-	-	0.5%

As with CAGR, for AAGR there is a choice to make about what period to rely on for forecasting the future (e.g., spanning 6 years, 10 years, or something else). Table 145 summarizes the main advantages and disadvantages of the AAGR approach.

Table 145. Advantages and disadvantages of AAGR approach

Advantages	Disadvantages
AAGR relies on a set of data points (rather than just two as in the CAGR method), which smooths out the resulting growth rate.	AAGR can be biased towards larger changes in values, even if the series is mostly invariant.
This approach is widely used (outside of AESC) and understood.	This approach has not been used in previous AESC studies.

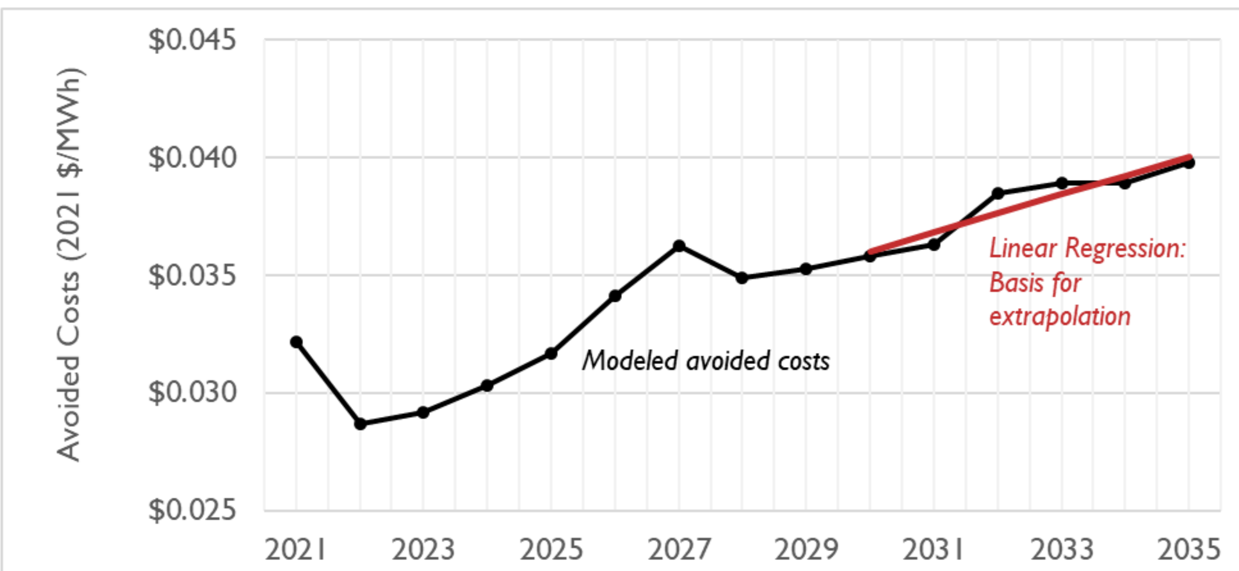
Calculating a growth rate based on a regression

The Synapse Team developed a third extrapolation option aimed at reconciling the following needs:

- The need to extrapolate future values using modeled values that are relatively "near" the extrapolated period
- The need to rely on extrapolate avoided costs that are representative of the recent trend, absent noise in the data

One way to achieve both of these goals is to smooth the values, then calculate the CAGR or AAGR. One smoothing technique is to perform a linear regression over the values in question. Figure 61 depicts a linear regression of the 2030 to 2035 datapoints in an example set of avoided costs. This linear regression creates a basis for extrapolation that is both (a) based on a set of "recent" values and (b) smooths the noise in the series.

Figure 61. Example of linear regression over a short period



We then calculate a CAGR using the first value in the regression and the last value in the regression. Alternately, we could instead calculate the AAGR over the same period (starting with the annual growth rate observed between the second point in the regression and the first point, and so on). For many regressions, these two growth rates will be virtually identical (e.g., within one one-tenth of a percent), with the AAGR being slightly larger than the CAGR due to the regression producing a constant unit change added to smaller, then larger, avoided costs. Table 146 summarizes the advantages and disadvantages of this approach.

Table 146. Advantages and disadvantages of regression-derived growth rate approach

Advantages	Disadvantages
This approach smooths the trend observed over a recent set of data points.	This approach has not been used in previous studies and was derived specifically for AESC.
Resulting CAGR and AAGR will be virtually identical for most series.	

Recommendation for extrapolation

In developing our recommendation, the Synapse Team notes the following:

- The Study Group has expressed a desire for a single extrapolation methodology for use across all avoided cost categories for ease of use.
- The Study Group has expressed a desire for an extrapolation technique to be both (a) based on data from years close to the extrapolation period and (b) be representative of the overall trend during this period (rather than being heavily weighted by one or two outlying data points).
- The "best" extrapolation method should be selected based on the one technique that best meets the needs expressed for extrapolation, rather than the one that produces the best-looking or most reasonable result for a particular avoided cost series.

The Synapse Team recommends the CAGR with regression technique as the extrapolation technique best suited to using recent values that are representative of a number of data points in each avoided cost series. In addition, we recommend increasing the timespan to 2030–2035. The addition of another year covers a period large enough to produce a less-noisy trend. The 2030–2035 time period also continues to represent a period of time that better represents post-2036 trends. The Synapse Team recommends using CAGR rather than AAGR as this method avoids the bias inherent in AAGR related to weighting unit changes applied to larger vs. smaller numbers.[347]

[347] There are two exceptions to this recommendation. First, we estimate capacity price shifts in 2036-2055 (used to calculate capacity DRIPE benefits in these years) by examining the median price shift from 2025 through 2035. A median is used rather than a trend plus CAGR because small year-on-year differences in demand or supply can produce substantial swings in price shifts in one year, followed by a return to the original price shift just one year later. These swings are much larger than any swings observed in other avoided cost inputs, and are an outcome of the stepwise supply function used by ISO New England (and deployed in AESC). This period is chosen because it is the period where capacity prices are projected, rather than based on observed auction data. The second exception is the final avoided cost streams for uncleared measures (e.g., uncleared capacity, uncleared capacity DRIPE). Because avoided costs in these categories vary by measure life, and because they are summed over the entire study period (rather than over the measure life as with all other avoided cost categories), we extrapolate the inputs used for these categories (e.g., capacity clearing prices, loads) but calculate avoided costs explicitly for each year through 2055.

Note that through the use of the *AESC 2021 User Interface* and other appendices, readers of AESC 2021 can calculate their own extrapolated values if their policy context requires some alternate methodology than the one recommended above.

Levelization calculations

The AESC Study 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: 2021 to 2030
- 15-year: 2021 to 2035
- 30-year: 2021 to 2050

All levelized costs are calculated using a real discount rate of 0.81 percent.

To calculate levelized costs beyond the three periods documented above, readers of AESC will require (a) a real discount rate (0.81 percent or otherwise specified), (b) the number of years and timeframe over which costs are to be levelized (e.g., 10 years—2021 through 2030 inclusive), and (c) the specific avoided cost values for the relevant reporting region. Equation 13 describes the formula used to estimate a levelized cost within Excel.

Equation 13. Excel formula used for calculating levelized costs

$$Levelized\ cost = -PMT(DiscountRate, NumberOfYears, NPV(DiscountRate, StreamOfCostsWithinPeriod))$$

Converting constant 2021 dollars to nominal dollars

Unless specifically noted, this report presents all dollar values in 2021 constant dollars. To convert constant 2021 dollars into nominal (current) dollars, apply the formula described in Equation 14. Inflator and deflator conversion factors for AESC 2021 are presented in *Appendix E: Common Financial Parameters*.

Equation 14. Nominal-constant dollar conversion

$$Nominal\ Value = \frac{Constant\ Value\ (in\ 2021\ \$)}{Annual\ Conversion\ Factor\ to\ 2021\ \$}$$

Comparisons to previous AESC studies

A reader of the AESC 2021 Study may prepare comparisons of the AESC 20221 Study's 15-year levelized avoided costs with the 2018 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 2021 and AESC 2018 (for the relevant reporting region and costing period)
- Convert the AESC 2018 values from 2018 dollars to 2021 dollars
- Calculate the 15-year levelized cost in 2021 dollars using the AESC 2021 real discount rate (0.81 percent)

APPENDIX B: DETAILED ELECTRIC OUTPUTS

AESC 2021 provides detailed avoided electricity cost projections, both energy and capacity, for each New England state. This appendix provides an overview of and instructions on how to apply those avoided costs. All values can be found in the *AESC 2021 User Interface* (see Appendix F: *User Interface* for more information) and state values are summarized in the standalone Excel file titled "Appendix B."[348]

Structure of Appendix B tables

For each state, Appendix B presents tables with the following avoided costs:

1. Avoided unit cost of electric energy
2. Avoided REC costs to load
3. Avoided non-embedded GHG costs
4. Avoided NO_X costs
5. Energy DRIPE for intrastate and rest-of-pool for 2021 installations
6. Electric Cross-DRIPE
7. Avoided unit cost of electric capacity by demand reduction bidding strategy
8. Capacity DRIPE for intrastate and rest-of-pool for 2021 installations
9. Avoided reliability costs
10. Avoided cost of pooled transmission facilities (PTF)

Illustrative levelized values are provided for each avoided cost.

Appendix B is organized into wholesale values, then retail values. Users typically do not need to use or modify the wholesale values directly, but users should apply values in accordance with state regulations.

Within these two categories, avoided costs are further arranged into avoided energy-based costs (presented in $ per kWh) and avoided capacity-based costs (presented in $ per kW-year).

[348] For comparative, historical purposes, we also estimate avoided costs for two subregions within Connecticut and three subregions within Massachusetts. Avoided costs for these subregions are not materially different from avoided costs for each of two relevant states. This subregional data is only found in the *AESC 2021 User Interface*.

Energy-based avoided costs, $ per kWh

Avoided electric energy costs are presented by year in four costing periods: on-peak winter, off-peak winter, on-peak summer, off-peak summer. ISO New England defines these costing periods as follows:[349]

- Summer on-peak: The 16-hour block from 7 a.m. till 11 p.m., Monday–Friday (except ISO holidays), in the months of June–September (1,376 Hours, 15.7 percent of 8,760)[350]
- Summer off-peak: All other hours between 11 p.m. and 7 a.m., Monday–Friday, weekends, and ISO holidays in the months of June–September (1,552 Hours, 17.7 percent of 8,760)
- Winter on-peak: The 16-hour block from 7 a.m. till 11 p.m., Monday–Friday (except ISO holidays), in the eight months of January–May and October–December (2,720 Hours, 31.0 percent of 8,760)
- Winter off-peak: All other hours between 11 p.m. and 7 a.m., Monday–Friday, all day on weekends, and ISO holidays–in the months of January–May and October–December (3,112 Hours, 35.5 percent of 8,760)

The annual avoided electricity cost for a given year, or set of years, is equal to the hour-weighted average of avoided costs for each of the four costing periods of that year (see Equation 15).

Equation 15. Calculation of annual avoided electricity cost

$$\begin{aligned} &Annual\ avoided\ electricity\ cost \\ &\qquad = (15.7\% \times Summer\ OnPeak) + (17.7\% \times Summer\ OffPeak) \\ &\qquad + (31.0\% \times Winter\ OnPeak) + (35.5\% \times Winter\ OffPeak) \end{aligned}$$

The specific wholesale avoided energy costs included in Appendix B are explained below.

- *Wholesale avoided costs of electricity energy*. Annual wholesale electric energy prices are outputted from the EnCompass simulation runs.[351]
- *Wholesale REC costs to load*. Annual avoided REC costs are specific to each state.
- *Wholesale non-embedded GHG and NO_X costs.* Annual estimates of non-embedded CO_2 and NO_X values are provided for each of the four energy costing periods. Non-embedded costs of NO_X are included in Appendix B for the first time in AESC 2021 and

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[349] ISO New England. Last accessed March 10, 2021. "Glossary and Acronyms." *Iso-ne.com.* Available at https://www.iso-ne.com/participate/support/glossary-acronyms/.

[350] ISO New England holidays are New Year's Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

[351] The avoided energy costs are computed for the aggregate load shape in each zone by costing period as described in more detail in Section 4.3. New *England system demand*.

can be included in a program administrator's cost-effectiveness model if desired. These avoided costs are calculated in the same manner as non-embedded carbon costs.

- *Wholesale energy DRIPE*. Separate projections are provided for wholesale intrastate and rest-of-pool energy DRIPE.[352] Users should apply energy DRIPE values in accordance with relevant state regulations governing treatment of energy DRIPE. For example, Massachusetts only considers intrastate DRIPE benefits, whereas Rhode Island considers both intrastate and rest-of-pool DRIPE benefits.

- *Wholesale cross-DRIPE.* Annual wholesale electric cross-DRIPE values include both electric-gas cross-DRIPE and electric-gas-electric cross-DRIPE, which represents the benefits from a reduction in the quantity of electricity that reduces gas consumption and that subsequently reduces electric prices. Users should treat the avoided costs for electric cross-DRIPE similarly to energy DRIPE.

Capacity-based avoided costs, $ per kW-year

Most capacity-based avoided cost components—including wholesale avoided unit cost of electric capacity, wholesale capacity DRIPE, and reliability—are separated into cleared, uncleared, and weighted average values.

The *cleared* capacity columns provide estimates for FCA capacity prices reported on a calendar year basis. ISO New England generally reports capacity prices based on power-years (June 1 to May 31).

The *uncleared* capacity columns provide estimates for capacity based on uncleared capacity or unbid capacity avoided through energy efficiency measures. The values are multiplied by the capacity price load effect and reserve margin percentages. 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 2026 for measures installed in 2021.

Wholesale capacity DRIPE projections are provided for intrastate and rest-of-pool energy DRIPE for installation year 2021. Users should apply capacity DRIPE values in accordance with relevant state regulations governing treatment of capacity DRIPE.

Avoided cost for PTF is based on costs allocated to LSEs from ISO New England. This is the only capacity-based avoided cost that is not separated into cleared, uncleared, and weighted average values, because it is not part of the FCM. Utilities that use avoided PTF costs should include only local transmission investments (those not eligible for PTF treatment) in their own avoided transmission cost analyses.

In the *AESC 2021 User Interface*, users may specify a percentage of measures that are cleared in the FCM. This percentage is then used to calculate a weighted average avoided cost for cleared and uncleared capacity, cleared and uncleared capacity DRIPE, and cleared and uncleared reliability. The weighted average is based on a simplified bidding strategy consisting of *x* percent of demand reductions

[352] DRIPE vintage years are available for 2021 through 2025 within the *AESC 2021 User Interface*.

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.

How to convert wholesale avoided costs to retail avoided costs

AESC estimates avoided electric costs at the wholesale level, meaning reductions at power plants or energy markets. The *AESC 2021 User Interface* and Appendix B Excel workbooks allow users to convert the wholesale values to retail values. Retail avoided costs represent reductions at the customer meter or end-use level, and they are meant to approximate the price customers see on utility bills.

Depending on the avoided cost, two adjustment factors are applied to convert from wholesale to retail values: (1) a factor for transmission and distribution losses, and (2) a wholesale risk premium. Both factors are described in detail below. These adjustments gross up wholesale values, leading to retail values that are greater than wholesale values.

In general, the formula for converting from wholesale to retail is shown in Equation 16.

Equation 16. Converting from wholesale to retail avoided costs

$$Avoided\ retail\ cost = (avoided\ wholesale\ cost) \times (1 + losses) \times (1 + wholesale\ risk\ premium)$$

Wholesale risk premium

The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary-service. This is because retail suppliers incur various market risks when they set contract prices in advance of supply delivery. In AESC, this premium over wholesale prices is called the *wholesale risk premium*, and the default assumption is that retail prices are 8 percent greater than wholesale prices.

Types of risk

The wholesale risk premium accounts for multiple risks. First, there is the retail supplier's cost to mitigate cost risks. Retail suppliers mitigate some risk by hedging their costs in advance, but there is still uncertainty in the final price borne by the supplier. This includes cost risk from hourly energy balancing, 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 for utility standard-service offers run risks related to customer migration. Customers may migrate from the utility's standard offer service to competitive supply, presumably at times of low market prices, leaving the supplier to sell surplus into a weak market at a loss. Alternatively, customers may switch from competitive supply to the utility's standard offer service at times of high market prices, forcing the supplier to purchase additional power in a high-cost market.

Estimating the wholesale risk premium

Estimates of the appropriate premium range from less than 5 percent to around 10 percent, based on analyses of confidential supplier bids—primarily in Massachusetts, Connecticut, and Maryland—to which the Synapse Team or sponsors have been privy.[353] 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 tend to see the resulting costs incorporated into the adders in supplier bids.[354] AESC 2021 uses a wholesale risk premium of 8 percent to reflect these dynamics.

AESC 2021 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[355]

The risk premium is a separate input to the avoided-cost spreadsheet. Therefore, 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.

Members of the Study Group have inquired if a similar wholesale risk premium could be applied for natural gas efficiency programs. Natural gas marketers also undertake contracts of varying durations for future delivery and account for risks in their retail pricing. The current scope of AESC 2021 does not include the development of a wholesale risk premium for natural gas, but such work could be included in future AESC studies or updates to this study.

[353] Note that these bids are confidential and cannot be made public.

[354] The default value for Vermont is set in accordance with guidance from the Vermont PUC, which also specifies a default value for municipal utilities. These utilities typically either procure a basket of generation resources or contract for bundled service from suppliers.

[355] Capacity costs present a different risk profile than energy costs. With the FCM, suppliers have a good estimate of the capacity price three years in advance and of the capacity requirement for 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, RPSs, and other factors. Given the uncertainty and variability in the overall risk premium, we do not believe that differentiating between energy and capacity premiums is warranted. We thus apply the retail premium uniformly to both energy and capacity values.

Transmission and distribution losses

There is a loss of electricity between a generating unit and ISO New England's delivery points. Therefore, a kilowatt load reduction at the ISO New England's delivery points 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. These losses occur on both the transmission and distribution systems and apply to both energy and capacity avoided costs.[356]

When converting from wholesale to retail values, program administrators can use the default T&D loss value in AESC of 8 percent, or program administrators can use their own custom T&D loss factors.

AESC T&D losses

AESC converts avoided costs from wholesale to retail values assuming marginal losses of 9 percent for energy (i.e., all avoided cost categories that are described in terms of $ per kWh) and 16 percent for peak demand (i.e., all avoided cost categories that are described in terms of $ per kW-year). Table 147 displays the recommended loss factors, along with the average factors from which they are derived. We note that previous editions of AESC have typically recommended a loss factor of 8 percent be applied to all avoided cost categories.[357] However, this loss factor is average (rather than marginal) and focused on peak hours (rather than all hours). As a result, we have updated the recommended loss factors in AESC 2021. See Section 4.3 *New England system demand* for more discussion on deriving marginal loss factors.

Table 147. Loss factors recommended for use in AESC 2021

	Energy	Peak Demand
Average	6% *(a)*	8% *(c)*
Marginal *Recommended in AESC 2021*	9% *(b)*	16% *(d)*

Sources: (a) https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf, slide 25; (b) 1.5 x 6%, per 2011 RAP paper; (c) ISO New England Market Rules, Section III.13.1.4.1.1.6.(a); (d) 2 x 8%, per 2011 RAP paper.

Custom T&D losses

If a program administrator chooses to apply custom T&D loss values, it needs to consider three types of losses: distribution losses, transmission non-PTF losses, and transmission PTF losses. Below, we estimate

[356] The forecast of capacity costs from the FCM do not reflect these losses; therefore forecasted capacity costs should be adjusted to account for them.

[357] Note that this 8 percent value includes both transmission losses (2.5 percent) and distribution losses (5.5 percent). ISO New England. October 10, 2019. *Transmission planning Technical Guide.* Available at https://www.iso-ne.com/static-assets/documents/2017/03/transmission_planning_techincal_guide_rev6.pdf.

PTF losses and describe the need for program administrators to derive their own non-PTF costs. These two components could then be added to custom distribution losses values, perhaps developed using the guidance in Section 10.4: *Localized value of avoided T&D*.

PTF 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 and non-PTF demand that enable to us to estimate PTF losses.[358] On average, system PTF losses between 2010 and 2020 are 1.6 percent. This is the same number described in AESC 2018.

PTF losses probably vary among zones, because 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. However, marginal losses by zone could not be identified using the available data provided by ISO New England in December 2020, and it would be difficult to estimate from historical data anyway. Therefore, we use average losses for AESC 2021.

Non-PTF losses

AESC does not recommend a calculation for non-PTF losses at this time. Utilities who wish to develop a custom T&D factor should examine their own data and formulate their own non-PTF losses as appropriate. These non-PTF losses include losses over the non-PTF transmission substations and lines to distribution substations.

Applying wholesale to retail factors

Table 148 summarizes which retail factors are applied when converting wholesale avoided cost to retail avoided costs. Losses apply to all avoided costs.[359] Losses are applied to avoided capacity costs to be consistent with how generation capacity is procured or avoided.

The wholesale risk premium is applied to energy values except non-embedded values and to uncleared capacity values. The wholesale risk premium does not apply to non-embedded values because, by definition, these costs are not embedded in electricity prices; therefore retail suppliers do not include these costs in supply contracts. The wholesale risk premium does not apply to cleared capacity values because resources cleared in the FCM receive FCM prices.

Avoided PTF costs, represent avoided infrastructure investments, which would not be impacted by line losses or wholesale market risks.

[358] ISO New England defines system load as the sum of generation and net interchange, minus pumping load, and non-PTF demand. ISO New England uses the term "non-PTF demand" 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.

[359] This includes avoided PTF costs. Avoided PTF costs are calculated on the basis of dollars per *generating* kW. In order to be applied to retail kW savings, they must be increased by a loss factor.

Table 148. Wholesale to retail factors by avoided cost category

Avoided cost categories	Losses	Wholesale Risk Premium
Electric energy, energy DRIPE, cross-DRIPE	✓	✓
Non-embedded GHG, non-embedded NOx	✓	
Cleared capacity, capacity DRIPE, reliability	✓	
Uncleared capacity, capacity DRIPE, reliability	✓	✓
PTF losses	✓	

Guide to applying the avoided costs

AESC 2021 allows users to specify certain inputs as well as to choose which of the avoided cost components to include in their analyses. The retail avoided costs are calculated using the following default values:

1. Wholesale risk premium: 8 percent[360]
2. Losses: 9 percent for dollar-per-kWh values and 16 percent for dollar-per-kW values[361]
3. Real discount rate: 0.81 percent

Users may insert their own values for these input assumptions. 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 on the "User Results" page.

[360] The wholesale risk premium for Vermont is 11.1 percent per Vermont DPS. See Appendix A for a more detailed discussion of the wholesale risk premium.

[361] Each program administrator should obtain or calculate the losses applicable to its specific system as described in Chapter 10 on avoided T&D costs.

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. Values are also provided in the standalone Excel workbook titled "Appendix C."

Avoided natural gas costs by end-use

Table 150 through Table 154 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 150 through Table 154 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 155 through Table 160 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. New in AESC 2021, we also display both zone-on-zone and zone-on-rest-of-pool (ROP) values.[362]

[362] Previous versions of AESC directed users of the study to calculate zone-on-Rest-of-Pool values on their own, by subtracting the state values from the New England-wide value. We now present these values separately and explicitly for the reader's convenience.

Column 1 of each of these tables shows gas supply DRIPE for measures installed in 2021. Program administrators can use the 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. An analogous value for zone-on-Rest-of-Pool DRIPE appears in Column 10.

Columns 2 through 9 show gas-electric (G-E) cross-fuel DRIPE by costing period and load segment for each state. Program administrators can use the value by year from these columns and apply them to the MMBtu of gas reduction from the relevant costing period and load segment. These values are calculating using the end-use share assumptions depicted in Table 149.[363]

Table 149. End-use and sector share assumptions used to calculate G-E cross-DRIPE

Sector	End-Use	Share of Sector	Share of Total Consumption
Residential	Non heating	6%	
Residential	Hot water	27%	40%
Residential	Heating	67%	
Commercial & Industrial	Non heating	27%	60%
Commercial & Industrial	Heating	73%	

Note: DRIPE effects for "Non Heating" and "Hot Water" in residential are identical. They are reported separately to facilitate formulas in many program administrators' benefit-cost models. Conversely, commercial & industrial "Non heating" includes hot water measures, but are combined to facilitate their use in the benefit-cost models.

An analogous set of values are shown for zone-on-Rest-of-Pool DRIPE in Columns 11 through 18.

Avoided natural gas costs by costing period

Avoided natural gas costs are shown in Table 161 and Table 162 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 to derive the avoided costs by end-use that are presented in Table 150 and Table 153. 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 150 and the Baseload values in Table 161 are the same.

The values in Table 161 and Table 162 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

[363] In AESC 2021, the "share of sector" percentages are calculated by using New England-specific data from EIA's 2015 RECS survey (EIA. Last accessed March 10, 2021. *2015 RECS Survey.* Available at https://www.eia.gov/consumption/residential/data/2015/c&e/ce4.2.xlsx.)
"Share of total consumption" percentages are calculated based on 2014-2019 data for all six New England states obtained from EIA. "Natural Gas Consumption by End Use." *Eia.gov*. Available at https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SME_a.htm.
Note that prior editions of AESC utilized data supplied by National Grid.

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 150. Avoided cost of gas to retail customers by end-use for southern New England (SNE) assuming no avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	4.45	5.21	6.92	6.21	5.29	6.42	5.92	6.07
2022	4.24	5.11	7.08	6.26	5.20	6.50	5.93	6.11
2023	4.03	4.90	6.84	6.03	4.98	6.27	5.71	5.88
2024	4.35	5.22	7.17	6.35	5.30	6.60	6.03	6.20
2025	4.41	5.28	7.22	6.41	5.36	6.65	6.09	6.26
2026	4.52	5.38	7.31	6.51	5.46	6.75	6.19	6.36
2027	4.58	5.43	7.36	6.56	5.52	6.80	6.24	6.41
2028	4.72	5.58	7.50	6.70	5.66	6.94	6.38	6.55
2029	4.85	5.70	7.62	6.82	5.79	7.06	6.50	6.67
2030	4.91	5.76	7.67	6.87	5.84	7.11	6.56	6.73
2031	4.92	5.77	7.67	6.88	5.86	7.12	6.57	6.73
2032	4.99	5.84	7.73	6.94	5.92	7.18	6.63	6.80
2033	5.06	5.90	7.79	7.00	5.98	7.24	6.69	6.86
2034	5.08	5.92	7.80	7.02	6.01	7.25	6.71	6.87
2035	5.09	5.93	7.80	7.02	6.01	7.25	6.71	6.88
2036	5.14	5.97	7.83	7.05	6.05	7.29	6.75	6.91
2037	5.18	6.01	7.86	7.09	6.09	7.32	6.78	6.95
2038	5.22	6.05	7.90	7.13	6.13	7.35	6.82	6.98
2039	5.27	6.09	7.93	7.16	6.17	7.39	6.86	7.02
2040	5.31	6.13	7.96	7.20	6.21	7.42	6.89	7.06
2041	5.36	6.17	7.99	7.23	6.25	7.46	6.93	7.09
2042	5.40	6.21	8.03	7.27	6.30	7.49	6.97	7.13
2043	5.45	6.25	8.06	7.31	6.34	7.53	7.01	7.17
2044	5.50	6.29	8.09	7.34	6.38	7.56	7.05	7.20
2045	5.54	6.34	8.13	7.38	6.42	7.60	7.08	7.24
2046	5.59	6.38	8.16	7.42	6.46	7.64	7.12	7.28
2047	5.64	6.42	8.19	7.45	6.51	7.67	7.16	7.32
2048	5.69	6.46	8.23	7.49	6.55	7.71	7.20	7.36
2049	5.73	6.51	8.26	7.53	6.59	7.74	7.24	7.39
2050	5.78	6.55	8.29	7.57	6.64	7.78	7.28	7.43
2051	5.83	6.59	8.33	7.60	6.68	7.82	7.32	7.47
2052	5.88	6.64	8.36	7.64	6.72	7.85	7.36	7.51
2053	5.93	6.68	8.40	7.68	6.77	7.89	7.40	7.55
2054	5.98	6.73	8.43	7.72	6.81	7.93	7.44	7.59
2055	6.03	6.77	8.47	7.76	6.86	7.97	7.48	7.63
Levelized (2021–2030)	4.50	5.35	7.26	6.47	5.44	6.70	6.15	6.32
Levelized (2021–2035)	4.67	5.52	7.42	6.63	5.60	6.86	6.31	6.48
Levelized (2021–2050)	5.03	5.86	7.72	6.94	5.95	7.17	6.64	6.80

Table 151. Avoided cost of gas to retail customers by end-use for southern New England (SNE) assuming some avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	5.41	6.17	8.30	7.56	6.07	7.82	7.35	7.43
2022	5.20	6.07	8.47	7.63	5.98	7.91	7.39	7.48
2023	4.99	5.86	8.23	7.40	5.76	7.68	7.16	7.26
2024	5.31	6.18	8.55	7.72	6.08	8.00	7.48	7.58
2025	5.37	6.24	8.61	7.78	6.14	8.06	7.54	7.64
2026	5.48	6.34	8.70	7.87	6.24	8.15	7.64	7.73
2027	5.54	6.39	8.75	7.92	6.30	8.20	7.69	7.78
2028	5.68	6.53	8.89	8.06	6.44	8.34	7.83	7.92
2029	5.80	6.66	9.01	8.19	6.57	8.47	7.95	8.05
2030	5.87	6.72	9.06	8.24	6.62	8.52	8.01	8.10
2031	5.88	6.73	9.06	8.25	6.64	8.52	8.01	8.11
2032	5.95	6.79	9.12	8.31	6.70	8.58	8.08	8.17
2033	6.02	6.86	9.18	8.37	6.76	8.64	8.13	8.23
2034	6.04	6.88	9.19	8.38	6.79	8.66	8.15	8.24
2035	6.05	6.89	9.19	8.38	6.79	8.66	8.15	8.25
2036	6.10	6.93	9.22	8.42	6.83	8.69	8.19	8.28
2037	6.14	6.97	9.25	8.45	6.87	8.73	8.22	8.32
2038	6.18	7.01	9.28	8.49	6.91	8.76	8.26	8.35
2039	6.23	7.05	9.31	8.52	6.95	8.80	8.30	8.39
2040	6.27	7.09	9.35	8.56	6.99	8.83	8.33	8.42
2041	6.32	7.13	9.38	8.59	7.03	8.86	8.37	8.46
2042	6.36	7.17	9.41	8.63	7.07	8.90	8.41	8.49
2043	6.41	7.21	9.44	8.66	7.11	8.93	8.44	8.53
2044	6.45	7.25	9.48	8.70	7.16	8.97	8.48	8.57
2045	6.50	7.29	9.51	8.74	7.20	9.00	8.52	8.60
2046	6.54	7.33	9.54	8.77	7.24	9.04	8.55	8.64
2047	6.59	7.38	9.58	8.81	7.28	9.08	8.59	8.68
2048	6.64	7.42	9.61	8.84	7.32	9.11	8.63	8.71
2049	6.69	7.46	9.64	8.88	7.37	9.15	8.67	8.75
2050	6.73	7.50	9.68	8.92	7.41	9.18	8.70	8.79
2051	6.78	7.55	9.71	8.95	7.45	9.22	8.74	8.83
2052	6.83	7.59	9.74	8.99	7.50	9.26	8.78	8.86
2053	6.88	7.64	9.78	9.03	7.54	9.29	8.82	8.90
2054	6.93	7.68	9.81	9.07	7.58	9.33	8.86	8.94
2055	6.98	7.72	9.85	9.10	7.63	9.37	8.89	8.98
Levelized (2021–2030)	5.46	6.31	8.65	7.83	6.22	8.11	7.60	7.69
Levelized (2021–2035)	5.63	6.48	8.81	7.99	6.38	8.27	7.76	7.85
Levelized (2021–2050)	5.99	6.82	9.11	8.31	6.72	8.58	8.08	8.17

Table 152. Avoided cost of gas to retail customers by end-use for northern New England (NNE) assuming no avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	4.28	5.13	7.04	6.24	5.21	6.48	5.93	6.10
2022	4.07	4.98	7.04	6.18	5.07	6.43	5.84	6.02
2023	3.86	4.76	6.79	5.95	4.85	6.19	5.60	5.79
2024	4.18	5.08	7.12	6.27	5.17	6.51	5.93	6.11
2025	4.25	5.15	7.17	6.33	5.24	6.57	5.99	6.17
2026	4.36	5.25	7.26	6.42	5.34	6.66	6.08	6.26
2027	4.42	5.30	7.30	6.47	5.39	6.71	6.13	6.31
2028	4.56	5.45	7.44	6.61	5.54	6.85	6.27	6.45
2029	4.69	5.57	7.56	6.73	5.66	6.97	6.40	6.57
2030	4.75	5.63	7.61	6.78	5.72	7.02	6.45	6.63
2031	4.77	5.64	7.61	6.79	5.73	7.02	6.46	6.64
2032	4.84	5.71	7.67	6.85	5.80	7.08	6.52	6.70
2033	4.91	5.77	7.72	6.91	5.86	7.14	6.58	6.76
2034	4.94	5.80	7.73	6.93	5.89	7.15	6.60	6.77
2035	4.95	5.80	7.73	6.93	5.89	7.15	6.60	6.78
2036	5.00	5.84	7.76	6.96	5.93	7.19	6.64	6.81
2037	5.04	5.89	7.79	7.00	5.98	7.22	6.68	6.85
2038	5.09	5.93	7.82	7.03	6.02	7.25	6.71	6.88
2039	5.14	5.97	7.85	7.07	6.06	7.29	6.75	6.92
2040	5.18	6.01	7.88	7.10	6.10	7.32	6.79	6.95
2041	5.23	6.05	7.91	7.14	6.14	7.35	6.82	6.99
2042	5.28	6.10	7.94	7.17	6.18	7.39	6.86	7.03
2043	5.33	6.14	7.97	7.21	6.23	7.42	6.90	7.06
2044	5.38	6.18	8.00	7.24	6.27	7.45	6.94	7.10
2045	5.43	6.22	8.03	7.28	6.31	7.49	6.97	7.14
2046	5.48	6.27	8.07	7.32	6.36	7.52	7.01	7.17
2047	5.53	6.31	8.10	7.35	6.40	7.56	7.05	7.21
2048	5.58	6.36	8.13	7.39	6.45	7.59	7.09	7.25
2049	5.63	6.40	8.16	7.43	6.49	7.63	7.13	7.29
2050	5.68	6.45	8.19	7.46	6.53	7.66	7.17	7.33
2051	5.73	6.49	8.22	7.50	6.58	7.70	7.21	7.36
2052	5.79	6.54	8.26	7.54	6.63	7.73	7.25	7.40
2053	5.84	6.58	8.29	7.58	6.67	7.77	7.29	7.44
2054	5.89	6.63	8.32	7.61	6.72	7.81	7.33	7.48
2055	5.95	6.68	8.35	7.65	6.76	7.84	7.37	7.52
Levelized (2021–2030)	4.34	5.22	7.23	6.39	5.31	6.63	6.06	6.24
Levelized (2021–2035)	4.51	5.39	7.38	6.55	5.48	6.79	6.22	6.39
Levelized (2021–2050)	4.89	5.74	7.65	6.86	5.83	7.08	6.53	6.71

Table 153. Avoided cost of gas to retail customers by end-use for northern New England (NNE) assuming some avoidable retail margin (2021 $ per MMBtu)

Year	Residential				Commercial & Industrial			All Retail End-Uses
	Non heating	*Hot Water*	*Heating*	*All*	*Non heating*	*Heating*	*All*	
2021	5.24	6.09	8.43	7.61	5.99	7.89	7.38	7.47
2022	5.03	5.94	8.43	7.56	5.85	7.84	7.30	7.40
2023	4.82	5.72	8.18	7.32	5.63	7.60	7.06	7.17
2024	5.14	6.04	8.50	7.64	5.95	7.92	7.39	7.49
2025	5.21	6.11	8.55	7.70	6.02	7.97	7.45	7.55
2026	5.31	6.21	8.64	7.79	6.12	8.07	7.54	7.64
2027	5.38	6.26	8.69	7.84	6.17	8.12	7.59	7.69
2028	5.52	6.41	8.83	7.98	6.32	8.25	7.73	7.83
2029	5.65	6.53	8.94	8.10	6.44	8.37	7.85	7.95
2030	5.71	6.59	8.99	8.15	6.50	8.42	7.90	8.00
2031	5.73	6.60	8.99	8.16	6.51	8.43	7.91	8.01
2032	5.80	6.67	9.05	8.22	6.58	8.49	7.97	8.07
2033	5.87	6.73	9.11	8.28	6.64	8.55	8.03	8.13
2034	5.90	6.76	9.12	8.29	6.67	8.56	8.05	8.15
2035	5.91	6.76	9.11	8.29	6.67	8.56	8.05	8.15
2036	5.96	6.80	9.14	8.33	6.71	8.59	8.08	8.18
2037	6.00	6.85	9.17	8.36	6.75	8.63	8.12	8.22
2038	6.05	6.89	9.20	8.39	6.80	8.66	8.15	8.25
2039	6.10	6.93	9.23	8.43	6.84	8.69	8.19	8.29
2040	6.14	6.97	9.26	8.46	6.88	8.73	8.23	8.32
2041	6.19	7.01	9.30	8.50	6.92	8.76	8.26	8.36
2042	6.24	7.05	9.33	8.53	6.96	8.79	8.30	8.39
2043	6.28	7.10	9.36	8.57	7.01	8.83	8.33	8.43
2044	6.33	7.14	9.39	8.60	7.05	8.86	8.37	8.46
2045	6.38	7.18	9.42	8.64	7.09	8.89	8.41	8.50
2046	6.43	7.22	9.45	8.67	7.13	8.93	8.44	8.53
2047	6.48	7.27	9.48	8.71	7.18	8.96	8.48	8.57
2048	6.53	7.31	9.51	8.74	7.22	9.00	8.52	8.61
2049	6.58	7.36	9.54	8.78	7.26	9.03	8.55	8.64
2050	6.63	7.40	9.58	8.81	7.31	9.07	8.59	8.68
2051	6.68	7.44	9.61	8.85	7.35	9.10	8.63	8.72
2052	6.73	7.49	9.64	8.89	7.40	9.14	8.67	8.75
2053	6.78	7.53	9.67	8.92	7.44	9.17	8.70	8.79
2054	6.84	7.58	9.70	8.96	7.49	9.21	8.74	8.83
2055	6.89	7.62	9.73	9.00	7.53	9.24	8.78	8.87
Levelized (2021–2030)	5.30	6.18	8.61	7.76	6.09	8.04	7.51	7.61
Levelized (2021–2035)	5.47	6.35	8.76	7.92	6.26	8.19	7.67	7.77
Levelized (2021–2050)	5.85	6.70	9.04	8.22	6.61	8.49	7.98	8.08

Table 154. Avoided cost of gas to retail customers by end-use for Vermont assuming some avoidable retail margin (2021 $ per MMBtu)

Year	Residential			
	Design Day 1	*Peak Days* 9	*Remaining Winter* 141	*Shoulder / Summer* 214
2021	554.38	15.27	3.39	3.03
2022	554.43	15.39	3.43	3.07
2023	554.47	17.05	3.48	3.12
2024	555.04	17.09	4.05	3.68
2025	555.37	17.17	4.37	4.01
2026	555.71	17.28	4.72	4.35
2027	556.03	16.97	5.03	4.67
2028	556.42	17.20	5.43	5.07
2029	556.80	17.31	5.81	5.44
2030	557.10	17.65	6.11	5.75
2031	557.14	17.61	6.15	5.79
2032	557.22	17.65	6.23	5.87
2033	557.30	17.53	6.31	5.95
2034	557.34	17.78	6.35	5.99
2035	557.36	17.57	6.37	6.01
2036	557.42	17.57	6.43	6.07
2037	557.48	17.57	6.49	6.12
2038	557.53	17.57	6.55	6.18
2039	557.59	17.57	6.61	6.24
2040	557.65	17.57	6.67	6.30
2041	557.70	17.57	6.73	6.36
2042	557.76	17.57	6.79	6.43
2043	557.82	17.56	6.85	6.49
2044	557.87	17.56	6.91	6.55
2045	557.93	17.56	6.97	6.61
2046	557.99	17.56	7.04	6.68
2047	558.04	17.56	7.10	6.74
2048	558.10	17.56	7.17	6.81
2049	558.16	17.56	7.23	6.87
2050	558.21	17.56	7.30	6.94
2051	558.27	17.56	7.36	7.01
2052	558.33	17.56	7.43	7.07
2053	558.38	17.56	7.50	7.14
2054	558.44	17.56	7.57	7.21
2055	558.50	17.56	7.63	7.28
Levelized (2021–2030)	555.55	16.82	4.56	4.20
Levelized (2021–2035)	556.10	17.08	5.11	4.75
Levelized (2021–2050)	552.49	17.51	11.15	13.51

Table 155. Intrastate gas supply DRIPE and gas cross-DRIPE for Connecticut (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.00	0.24	0.24	0.44	0.38	0.24	0.44	0.39	0.38	0.02	1.21	1.21	2.21	1.88	1.21	1.21	1.21	1.48
2022	0.01	0.36	0.36	0.67	0.57	0.36	0.67	0.59	0.58	0.03	1.82	1.82	3.33	2.84	1.82	1.82	1.82	2.23
2023	0.01	0.44	0.44	0.81	0.68	0.44	0.81	0.71	0.70	0.03	2.08	2.08	3.80	3.24	2.08	2.08	2.08	2.54
2024	0.01	0.35	0.35	0.64	0.55	0.35	0.64	0.56	0.56	0.03	1.68	1.68	3.08	2.62	1.68	1.68	1.68	2.06
2025	0.01	0.24	0.24	0.45	0.38	0.24	0.45	0.39	0.39	0.03	1.43	1.43	2.61	2.23	1.43	1.43	1.43	1.75
2026	0.01	0.17	0.17	0.32	0.27	0.17	0.32	0.28	0.28	0.03	0.98	0.98	1.78	1.52	0.98	0.98	0.98	1.20
2027	0.01	0.12	0.12	0.21	0.18	0.12	0.21	0.19	0.19	0.03	0.61	0.61	1.09	0.93	0.61	0.61	0.61	0.74
2028	0.01	0.09	0.09	0.16	0.14	0.09	0.16	0.14	0.14	0.03	0.43	0.43	0.76	0.65	0.43	0.43	0.43	0.52
2029	0.01	0.06	0.06	0.10	0.08	0.06	0.10	0.08	0.08	0.03	0.27	0.27	0.46	0.39	0.27	0.27	0.27	0.32
2030	0.01	0.03	0.03	0.05	0.04	0.03	0.05	0.04	0.04	0.03	0.12	0.12	0.19	0.17	0.12	0.12	0.12	0.14
2031	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.00	0.00	0.03	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.01
2032	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.04	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	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.06	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	0.06	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	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.01	0.21	0.21	0.39	0.33	0.21	0.39	0.34	0.34	0.03	1.08	1.08	1.96	1.67	1.08	1.08	1.08	1.31
2021–2035	0.01	0.15	0.15	0.26	0.23	0.15	0.26	0.23	0.23	0.03	0.73	0.73	1.33	1.13	0.73	0.73	0.73	0.89
2021–2050	0.01	0.08	0.08	0.14	0.12	0.08	0.14	0.12	0.12	0.04	0.39	0.39	0.71	0.60	0.39	0.39	0.39	0.47

Table 156. Intrastate gas supply DRIPE and gas cross-DRIPE for Massachusetts (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.01	0.73	0.73	1.33	1.14	0.73	1.33	1.17	1.16	0.01	0.72	0.72	1.32	1.13	0.72	0.72	0.72	0.88
2022	0.02	1.09	1.09	1.99	1.69	1.09	1.99	1.74	1.72	0.02	1.10	1.10	2.01	1.71	1.10	1.10	1.10	1.34
2023	0.02	1.19	1.19	2.18	1.86	1.19	2.18	1.91	1.89	0.02	1.33	1.33	2.43	2.07	1.33	1.33	1.33	1.62
2024	0.02	0.93	0.93	1.70	1.44	0.93	1.70	1.49	1.47	0.02	1.10	1.10	2.02	1.72	1.10	1.10	1.10	1.35
2025	0.02	0.77	0.77	1.41	1.20	0.77	1.41	1.24	1.22	0.02	0.90	0.90	1.65	1.40	0.90	0.90	0.90	1.10
2026	0.02	0.51	0.51	0.93	0.80	0.51	0.93	0.82	0.81	0.02	0.64	0.64	1.17	1.00	0.64	0.64	0.64	0.79
2027	0.02	0.32	0.32	0.57	0.49	0.32	0.57	0.50	0.50	0.02	0.41	0.41	0.73	0.63	0.41	0.41	0.41	0.50
2028	0.02	0.23	0.23	0.40	0.34	0.23	0.40	0.35	0.35	0.02	0.29	0.29	0.52	0.44	0.29	0.29	0.29	0.35
2029	0.02	0.14	0.14	0.24	0.21	0.14	0.24	0.21	0.21	0.02	0.18	0.18	0.31	0.27	0.18	0.18	0.18	0.22
2030	0.03	0.06	0.06	0.10	0.09	0.06	0.10	0.09	0.09	0.02	0.09	0.09	0.14	0.12	0.09	0.09	0.09	0.10
2031	0.03	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
2032	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2034	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2035	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2036	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2037	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2038	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2039	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2040	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2041	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2042	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2043	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2044	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2045	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2046	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2047	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2048	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	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	0.03	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	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.02	0.61	0.61	1.10	0.94	0.61	1.10	0.97	0.95	0.02	0.68	0.68	1.25	1.06	0.68	0.68	0.68	0.84
2021–2035	0.02	0.41	0.41	0.75	0.64	0.41	0.75	0.66	0.65	0.02	0.47	0.47	0.85	0.72	0.47	0.47	0.47	0.57
2021–2050	0.03	0.22	0.22	0.40	0.34	0.22	0.40	0.35	0.34	0.02	0.25	0.25	0.45	0.38	0.25	0.25	0.25	0.30

Table 157. Intrastate gas supply DRIPE and gas cross-DRIPE for Maine (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*	*10*	*11*	*12*	*13*	*14*	*15*	*16*	*17*	*18*
2021	0.00	0.17	0.17	0.32	0.27	0.17	0.32	0.28	0.28	0.02	1.28	1.28	2.34	1.99	1.28	1.28	1.28	1.56
2022	0.00	0.26	0.26	0.49	0.41	0.26	0.49	0.43	0.42	0.03	1.92	1.92	3.52	2.99	1.92	1.92	1.92	2.35
2023	0.00	0.32	0.32	0.59	0.50	0.32	0.59	0.52	0.51	0.04	2.20	2.20	4.02	3.42	2.20	2.20	2.20	2.69
2024	0.00	0.28	0.28	0.51	0.43	0.28	0.51	0.45	0.44	0.04	1.76	1.76	3.21	2.73	1.76	1.76	1.76	2.15
2025	0.00	0.24	0.24	0.44	0.38	0.24	0.44	0.39	0.38	0.04	1.44	1.44	2.62	2.23	1.44	1.44	1.44	1.75
2026	0.00	0.17	0.17	0.31	0.27	0.17	0.31	0.28	0.27	0.04	0.99	0.99	1.79	1.53	0.99	0.99	0.99	1.20
2027	0.00	0.11	0.11	0.19	0.16	0.11	0.19	0.17	0.17	0.04	0.62	0.62	1.11	0.95	0.62	0.62	0.62	0.75
2028	0.00	0.08	0.08	0.13	0.11	0.08	0.13	0.12	0.12	0.04	0.44	0.44	0.78	0.67	0.44	0.44	0.44	0.54
2029	0.00	0.05	0.05	0.08	0.07	0.05	0.08	0.07	0.07	0.04	0.27	0.27	0.47	0.41	0.27	0.27	0.27	0.33
2030	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.04	0.13	0.13	0.20	0.18	0.13	0.13	0.13	0.15
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	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	0.04	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	0.04	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	0.04	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	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.06	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	0.06	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	0.06	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	0.06	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	0.07	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	0.07	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	0.07	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	0.08	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	0.08	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	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.17	0.17	0.31	0.27	0.17	0.31	0.28	0.27	0.04	1.12	1.12	2.03	1.73	1.12	1.12	1.12	1.36
2021–2035	0.00	0.12	0.12	0.21	0.18	0.12	0.21	0.19	0.19	0.04	0.76	0.76	1.38	1.18	0.76	0.76	0.76	0.93
2021–2050	0.00	0.06	0.06	0.11	0.10	0.06	0.11	0.10	0.10	0.05	0.40	0.40	0.73	0.62	0.40	0.40	0.40	0.49

Table 158. Intrastate gas supply DRIPE and gas cross-DRIPE for New Hampshire (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
2021	0.00	0.16	0.16	0.30	0.25	0.16	0.30	0.26	0.26	0.02	1.29	1.29	2.36	2.01	1.29	1.29	1.29	1.57
2022	0.00	0.25	0.25	0.46	0.39	0.25	0.46	0.40	0.40	0.03	1.94	1.94	3.54	3.02	1.94	1.94	1.94	2.37
2023	0.00	0.30	0.30	0.56	0.47	0.30	0.56	0.49	0.48	0.04	2.22	2.22	4.05	3.45	2.22	2.22	2.22	2.71
2024	0.00	0.27	0.27	0.50	0.42	0.27	0.50	0.44	0.43	0.04	1.76	1.76	3.22	2.74	1.76	1.76	1.76	2.16
2025	0.00	0.24	0.24	0.44	0.38	0.24	0.44	0.39	0.38	0.04	1.43	1.43	2.62	2.23	1.43	1.43	1.43	1.75
2026	0.00	0.17	0.17	0.31	0.27	0.17	0.31	0.27	0.27	0.04	0.99	0.99	1.79	1.53	0.99	0.99	0.99	1.20
2027	0.00	0.11	0.11	0.19	0.16	0.11	0.19	0.17	0.17	0.04	0.62	0.62	1.11	0.95	0.62	0.62	0.62	0.75
2028	0.00	0.07	0.07	0.13	0.11	0.07	0.13	0.12	0.12	0.04	0.45	0.45	0.78	0.67	0.45	0.45	0.45	0.54
2029	0.00	0.05	0.05	0.08	0.07	0.05	0.08	0.07	0.07	0.04	0.28	0.28	0.47	0.41	0.28	0.28	0.28	0.33
2030	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.04	0.13	0.13	0.21	0.18	0.13	0.13	0.13	0.15
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	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	0.04	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	0.04	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	0.04	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	0.05	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	0.05	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	0.05	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	0.05	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	0.06	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	0.06	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	0.06	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	0.06	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	0.07	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	0.07	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	0.07	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	0.07	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	0.08	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	0.08	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	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.17	0.17	0.30	0.26	0.17	0.30	0.27	0.26	0.04	1.12	1.12	2.04	1.74	1.12	1.12	1.12	1.37
2021–2035	0.00	0.11	0.11	0.21	0.18	0.11	0.21	0.18	0.18	0.04	0.77	0.77	1.39	1.18	0.77	0.77	0.77	0.93
2021–2050	0.00	0.06	0.06	0.11	0.09	0.06	0.11	0.10	0.10	0.05	0.41	0.41	0.74	0.63	0.41	0.41	0.41	0.49

Table 159. Intrastate gas supply DRIPE and gas cross-DRIPE for Rhode Island (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
2021	0.00	0.11	0.11	0.20	0.17	0.11	0.20	0.18	0.17	0.02	1.34	1.34	2.46	2.09	1.34	1.34	1.34	1.64
2022	0.00	0.17	0.17	0.31	0.26	0.17	0.31	0.27	0.27	0.03	2.01	2.01	3.70	3.14	2.01	2.01	2.01	2.47
2023	0.00	0.21	0.21	0.37	0.32	0.21	0.37	0.33	0.32	0.04	2.31	2.31	4.24	3.61	2.31	2.31	2.31	2.83
2024	0.00	0.16	0.16	0.28	0.24	0.16	0.28	0.24	0.24	0.04	1.88	1.88	3.44	2.93	1.88	1.88	1.88	2.30
2025	0.00	0.13	0.13	0.23	0.20	0.13	0.23	0.21	0.20	0.04	1.54	1.54	2.83	2.41	1.54	1.54	1.54	1.89
2026	0.00	0.10	0.10	0.17	0.14	0.10	0.17	0.15	0.15	0.04	1.06	1.06	1.94	1.65	1.06	1.06	1.06	1.30
2027	0.00	0.06	0.06	0.10	0.09	0.06	0.10	0.09	0.09	0.04	0.67	0.67	1.20	1.03	0.67	0.67	0.67	0.81
2028	0.00	0.04	0.04	0.07	0.06	0.04	0.07	0.06	0.06	0.04	0.48	0.48	0.85	0.73	0.48	0.48	0.48	0.58
2029	0.00	0.03	0.03	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.30	0.30	0.51	0.44	0.30	0.30	0.30	0.35
2030	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02	0.04	0.14	0.14	0.22	0.19	0.14	0.14	0.14	0.16
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	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	0.04	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	0.04	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	0.04	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	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.06	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	0.06	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	0.06	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	0.06	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	0.07	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	0.07	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	0.07	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	0.07	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	0.08	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	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.10	0.10	0.18	0.16	0.10	0.18	0.16	0.16	0.04	1.19	1.19	2.16	1.84	1.19	1.19	1.19	1.45
2021–2035	0.00	0.07	0.07	0.12	0.11	0.07	0.12	0.11	0.11	0.04	0.81	0.81	1.47	1.25	0.81	0.81	0.81	0.99
2021–2050	0.00	0.04	0.04	0.07	0.06	0.04	0.07	0.06	0.06	0.05	0.43	0.43	0.78	0.67	0.43	0.43	0.43	0.52

Table 160. Intrastate gas supply DRIPE and gas cross-DRIPE for Vermont (2021 $ per MMBtu)

	Zone-on-Zone									Zone-on-ROP								
	Gas Supply DRIPE	G-E Cross DRIPE								Gas Supply DRIPE	G-E Cross DRIPE							
		Residential				Commercial & Industrial			All end-uses		Residential				Commercial & Industrial			All end-uses
		Non Heating	Hot Water	Heating	All	Non Heating	Heating	All			Non Heating	Hot Water	Heating	All	Non Heating	Heating	All	
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
2021	0.00	0.03	0.03	0.06	0.05	0.03	0.06	0.05	0.05	0.02	1.42	1.42	2.59	2.21	1.42	1.42	1.42	1.73
2022	0.00	0.05	0.05	0.09	0.08	0.05	0.09	0.08	0.08	0.03	2.14	2.14	3.91	3.33	2.14	2.14	2.14	2.61
2023	0.00	0.06	0.06	0.11	0.09	0.06	0.11	0.09	0.09	0.04	2.46	2.46	4.50	3.83	2.46	2.46	2.46	3.01
2024	0.00	0.05	0.05	0.10	0.08	0.05	0.10	0.08	0.08	0.04	1.98	1.98	3.62	3.09	1.98	1.98	1.98	2.42
2025	0.00	0.04	0.04	0.08	0.07	0.04	0.08	0.07	0.07	0.04	1.63	1.63	2.98	2.54	1.63	1.63	1.63	1.99
2026	0.00	0.03	0.03	0.06	0.05	0.03	0.06	0.05	0.05	0.04	1.13	1.13	2.04	1.74	1.13	1.13	1.13	1.37
2027	0.00	0.02	0.02	0.03	0.03	0.02	0.03	0.03	0.03	0.04	0.71	0.71	1.27	1.09	0.71	0.71	0.71	0.86
2028	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02	0.04	0.51	0.51	0.89	0.77	0.51	0.51	0.51	0.61
2029	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.05	0.31	0.31	0.54	0.46	0.31	0.31	0.31	0.37
2030	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.01	0.00	0.05	0.15	0.15	0.23	0.20	0.15	0.15	0.15	0.17
2031	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02
2032	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.05	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	0.06	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	0.06	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	0.06	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	0.07	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	0.07	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	0.07	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	0.07	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	0.08	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	0.08	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	0.08	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	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2051	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2052	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2053	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2054	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2055	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Levelized																		
2021–2030	0.00	0.03	0.03	0.06	0.05	0.03	0.06	0.05	0.05	0.04	1.26	1.26	2.29	1.95	1.26	1.26	1.26	1.54
2021–2035	0.00	0.02	0.02	0.04	0.03	0.02	0.04	0.03	0.03	0.04	0.86	0.86	1.56	1.33	0.86	0.86	0.86	1.05
2021–2050	0.00	0.01	0.01	0.02	0.02	0.01	0.02	0.02	0.02	0.05	0.45	0.45	0.82	0.70	0.45	0.45	0.45	0.55

Table 161. Avoided natural gas costs by costing period – southern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	*365*	*273*	*151*	*90*	*30*	*10*
2021	$4.45	$5.61	$7.69	$8.67	$16.69	$29.84
2022	$4.24	$5.44	$7.69	$10.19	$19.27	$33.14
2023	$4.03	$5.20	$7.41	$10.03	$18.98	$32.63
2024	$4.35	$5.52	$7.73	$10.35	$19.51	$33.20
2025	$4.41	$5.57	$7.76	$10.42	$19.61	$33.22
2026	$4.52	$5.66	$7.84	$10.54	$19.79	$33.33
2027	$4.58	$5.71	$7.86	$10.61	$19.89	$33.34
2028	$4.72	$5.85	$7.99	$10.76	$20.15	$33.56
2029	$4.85	$5.96	$8.09	$10.91	$20.37	$33.75
2030	$4.91	$6.01	$8.12	$10.97	$20.47	$33.77
2031	$4.92	$6.02	$8.11	$11.00	$20.49	$33.68
2032	$4.99	$6.08	$8.15	$11.08	$20.61	$33.73
2033	$5.06	$6.13	$8.19	$11.15	$20.72	$33.77
2034	$5.08	$6.15	$8.19	$11.18	$20.76	$33.72
2035	$5.09	$6.15	$8.17	$11.20	$20.77	$33.63
2036	$5.14	$6.18	$8.19	$11.25	$20.83	$33.61
2037	$5.18	$6.21	$8.20	$11.30	$20.90	$33.59
2038	$5.22	$6.25	$8.22	$11.35	$20.97	$33.58
2039	$5.27	$6.28	$8.23	$11.40	$21.04	$33.56
2040	$5.31	$6.31	$8.25	$11.45	$21.11	$33.55
2041	$5.36	$6.34	$8.26	$11.50	$21.18	$33.53
2042	$5.40	$6.38	$8.28	$11.55	$21.25	$33.52
2043	$5.45	$6.41	$8.29	$11.60	$21.32	$33.50
2044	$5.50	$6.45	$8.31	$11.66	$21.39	$33.48
2045	$5.54	$6.48	$8.32	$11.71	$21.46	$33.47
2046	$5.59	$6.51	$8.34	$11.76	$21.54	$33.45
2047	$5.64	$6.55	$8.35	$11.81	$21.61	$33.44
2048	$5.69	$6.58	$8.37	$11.87	$21.68	$33.42
2049	$5.73	$6.62	$8.38	$11.92	$21.75	$33.40
2050	$5.78	$6.65	$8.40	$11.97	$21.82	$33.39
2051	$5.83	$6.69	$8.41	$12.03	$21.89	$33.37
2052	$5.88	$6.72	$8.43	$12.08	$21.97	$33.36
2053	$5.93	$6.76	$8.45	$12.13	$22.04	$33.34
2054	$5.98	$6.79	$8.46	$12.19	$22.11	$33.33
2055	$6.03	$6.83	$8.48	$12.24	$22.19	$33.31

Table 162. Avoided natural gas costs by costing period – northern New England (2021 $ per MMBtu)

Years	Baseload	Winter/Shoulder	Winter	Top 90	Top 30	Top 10
Days	*365*	*273*	*151*	*90*	*30*	*10*
2021	$4.28	$5.33	$7.23	$11.55	$19.19	$30.24
2022	$4.07	$5.17	$7.24	$11.65	$21.82	$31.77
2023	$3.86	$4.94	$6.96	$11.30	$21.58	$31.63
2024	$4.18	$5.26	$7.29	$11.60	$22.15	$31.96
2025	$4.25	$5.32	$7.33	$11.60	$22.30	$32.05
2026	$4.36	$5.41	$7.41	$11.63	$22.53	$32.18
2027	$4.42	$5.47	$7.45	$11.63	$22.67	$32.26
2028	$4.56	$5.60	$7.58	$11.71	$22.97	$32.44
2029	$4.69	$5.72	$7.69	$11.78	$23.24	$32.59
2030	$4.75	$5.78	$7.73	$11.78	$23.38	$32.68
2031	$4.77	$5.79	$7.72	$11.73	$23.44	$32.71
2032	$4.84	$5.85	$7.77	$11.74	$23.60	$32.80
2033	$4.91	$5.91	$7.82	$11.75	$23.75	$32.89
2034	$4.94	$5.93	$7.82	$11.71	$23.83	$32.94
2035	$4.95	$5.93	$7.81	$11.66	$23.87	$32.96
2036	$5.00	$5.97	$7.83	$11.64	$23.98	$33.03
2037	$5.04	$6.00	$7.85	$11.63	$24.09	$33.09
2038	$5.09	$6.04	$7.88	$11.61	$24.20	$33.15
2039	$5.14	$6.08	$7.90	$11.59	$24.31	$33.22
2040	$5.18	$6.11	$7.92	$11.57	$24.43	$33.28
2041	$5.23	$6.15	$7.94	$11.55	$24.54	$33.34
2042	$5.28	$6.19	$7.96	$11.54	$24.65	$33.41
2043	$5.33	$6.23	$7.99	$11.52	$24.76	$33.47
2044	$5.38	$6.27	$8.01	$11.50	$24.88	$33.54
2045	$5.43	$6.30	$8.03	$11.48	$24.99	$33.60
2046	$5.48	$6.34	$8.05	$11.46	$25.11	$33.66
2047	$5.53	$6.38	$8.08	$11.45	$25.22	$33.73
2048	$5.58	$6.42	$8.10	$11.43	$25.34	$33.79
2049	$5.63	$6.46	$8.12	$11.41	$25.45	$33.86
2050	$5.68	$6.50	$8.14	$11.39	$25.57	$33.92
2051	$5.73	$6.54	$8.17	$11.37	$25.69	$33.99
2052	$5.79	$6.58	$8.19	$11.36	$25.80	$34.05
2053	$5.84	$6.62	$8.21	$11.34	$25.92	$34.12
2054	$5.89	$6.66	$8.23	$11.32	$26.04	$34.18
2055	$5.95	$6.70	$8.26	$11.30	$26.16	$34.25

APPENDIX D: DETAILED OIL AND OTHER FUELS 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 (2021–2030), 15-year (2021–2035), and 30-year periods (2021–2050). 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 163 provides the avoided costs for three types of fuel:

- Fuel Oils, which includes distillate fuel oil, residual fuel oil, and a weighted average
- Other Fuels, which includes cord wood, wood pellets, kerosene, and propane
- Transportation fuels, including motor gasoline and motor diesel

Avoided costs for these fuels are shown by year and by applicable sector (residential, commercial, industrial, and/or transportation).

Table 164, Table 165, Table 166, and Table 167 provide information on DRIPE values for specific petroleum products. These tables modify the values shown in Table 104 by multiplying those by the adjustment factors described in Table 105.

All values are also provided in the standalone Excel workbook titled “Appendix D.”

Table 163. Avoided costs of petroleum fuels and other fuels by sector (2021 $ per MMBtu)

Year	Fuel oils							Other Fuels					Transportation	
	Residential	Commercial			Industrial			Residential				Industrial		
	Distillate Fuel Oil	Distillate Fuel Oil	Residual Fuel Oil	Weighted	Distillate Fuel Oil	Residual Fuel Oil	Weighted	Cord Wood	Wood Pellets	Kero-sene	Pro-pane	Kero-sene	Motor Gasoline	Motor Diesel
2021	$19	$21	$15	$21	$20	$15	$20	$17	$18	$24	$34	$17	$20	$20
2022	$19	$20	$14	$20	$19	$14	$19	$17	$18	$24	$34	$16	$21	$20
2023	$21	$21	$15	$21	$20	$15	$20	$19	$20	$26	$36	$17	$21	$21
2024	$23	$21	$15	$21	$21	$15	$20	$20	$21	$28	$37	$17	$21	$22
2025	$23	$22	$15	$21	$21	$15	$20	$20	$22	$29	$38	$18	$21	$22
2026	$24	$22	$15	$21	$21	$15	$20	$21	$23	$30	$39	$18	$21	$22
2027	$25	$22	$15	$22	$21	$15	$21	$21	$23	$30	$39	$18	$21	$23
2028	$25	$22	$16	$22	$22	$16	$21	$22	$23	$31	$40	$18	$22	$23
2029	$25	$23	$16	$22	$22	$16	$21	$22	$24	$31	$40	$18	$22	$23
2030	$26	$23	$16	$23	$22	$16	$22	$22	$24	$32	$40	$19	$23	$24
2031	$26	$23	$16	$23	$22	$16	$22	$22	$24	$32	$41	$19	$23	$24
2032	$26	$23	$17	$23	$23	$17	$22	$23	$24	$32	$41	$19	$24	$24
2033	$26	$24	$17	$23	$23	$17	$22	$23	$25	$32	$41	$19	$24	$24
2034	$26	$24	$17	$23	$23	$17	$22	$23	$25	$32	$41	$19	$24	$25
2035	$27	$24	$17	$24	$23	$17	$23	$23	$25	$33	$41	$19	$24	$25
2036	$27	$24	$17	$24	$23	$17	$23	$23	$25	$33	$41	$20	$25	$25
2037	$27	$24	$17	$24	$23	$17	$23	$23	$25	$33	$42	$20	$25	$25
2038	$27	$24	$17	$24	$24	$17	$23	$23	$25	$33	$42	$20	$25	$25
2039	$27	$25	$17	$24	$24	$17	$23	$24	$25	$33	$42	$20	$25	$25
2040	$27	$25	$18	$25	$24	$18	$23	$24	$26	$34	$42	$20	$26	$26
2041	$28	$25	$18	$25	$24	$18	$24	$24	$26	$34	$42	$20	$26	$26
2042	$28	$25	$18	$25	$24	$18	$24	$24	$26	$34	$42	$21	$26	$26
2043	$28	$25	$18	$25	$25	$18	$24	$24	$26	$34	$43	$21	$27	$26
2044	$28	$26	$18	$25	$25	$18	$24	$24	$26	$35	$43	$21	$27	$26
2045	$28	$26	$18	$25	$25	$18	$24	$25	$26	$35	$43	$21	$27	$26
2046	$28	$26	$18	$26	$25	$18	$25	$25	$27	$35	$43	$21	$28	$27
2047	$29	$26	$19	$26	$25	$19	$25	$25	$27	$35	$43	$21	$28	$27
2048	$29	$26	$19	$26	$26	$19	$25	$25	$27	$35	$44	$22	$28	$27
2049	$29	$27	$19	$26	$26	$19	$25	$25	$27	$36	$44	$22	$29	$27
2050	$29	$27	$19	$26	$26	$19	$25	$25	$27	$36	$44	$22	$29	$27
2051	$29	$27	$19	$27	$26	$19	$26	$25	$27	$36	$44	$22	$29	$28
2052	$30	$27	$19	$27	$26	$19	$26	$26	$28	$36	$44	$22	$30	$28
2053	$30	$27	$19	$27	$27	$19	$26	$26	$28	$37	$44	$22	$30	$28
2054	$30	$28	$20	$27	$27	$20	$26	$26	$28	$37	$45	$23	$30	$28
2055	$30	$28	$20	$28	$27	$20	$26	$26	$28	$37	$45	$23	$31	$28
2021-2029	$23	$22	$15	$21	$21	$15	$20	$20	$22	$28	$38	$18	$21	$22
2021-2035	$24	$22	$16	$22	$21	$16	$21	$21	$22	$30	$39	$18	$22	$23
2021-2050	$26	$24	$17	$23	$23	$17	$22	$22	$24	$32	$41	$19	$24	$24

Note: Assumes a real discount rate of 0.81 percent.

Table 164. Home heating (diesel) fuel DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.09	0.02	0.04	0.01	0.01	0.01	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2022	0.09	0.02	0.04	0.01	0.01	0.01	0.01	0.07	0.05	0.08	0.08	0.09	0.09
2023	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.09	0.09
2024	0.11	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.10	0.10
2025	0.11	0.02	0.05	0.01	0.01	0.01	0.01	0.09	0.06	0.10	0.10	0.10	0.10
2026	0.11	0.03	0.05	0.01	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2027	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2028	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2029	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2030	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2031	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2032	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2033	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2034	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2035	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2036	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2037	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.11	0.12	0.12
2038	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2039	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2040	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2041	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2042	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.13
2043	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2044	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2045	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2046	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2047	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2048	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2049	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2050	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2051	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2052	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2053	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
2054	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
2055	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
Levelized (2021–2035)	0.11	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11

Table 165. Residual fuel DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.05	0.01	0.02	0.01	0.01	0.00	0.00	0.04	0.03	0.04	0.04	0.05	0.05
2022	0.05	0.01	0.02	0.01	0.01	0.00	0.00	0.04	0.03	0.05	0.05	0.05	0.05
2023	0.06	0.01	0.02	0.01	0.01	0.00	0.00	0.05	0.03	0.05	0.05	0.06	0.06
2024	0.06	0.01	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.05	0.06	0.06	0.06
2025	0.06	0.01	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2026	0.07	0.01	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2027	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06
2028	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.07	0.07
2029	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.06	0.07	0.07
2030	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.06	0.07	0.07
2031	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2032	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2033	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2034	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2035	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.06	0.07	0.07	0.07
2036	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2037	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2038	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2039	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2040	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.04	0.07	0.07	0.07	0.07
2041	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2042	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2043	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2044	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2045	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.07
2046	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.07	0.08
2047	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2048	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2049	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2050	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2051	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2052	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2053	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2054	0.08	0.02	0.03	0.01	0.01	0.00	0.00	0.06	0.05	0.07	0.07	0.08	0.08
2055	0.08	0.02	0.04	0.01	0.01	0.00	0.00	0.07	0.05	0.07	0.07	0.08	0.08
Levelized (2021–2035)	0.07	0.02	0.03	0.01	0.01	0.00	0.00	0.05	0.04	0.06	0.06	0.06	0.06

Table 166. Motor gasoline DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.08	0.02	0.04	0.01	0.01	0.00	0.00	0.07	0.05	0.07	0.08	0.08	0.08
2022	0.09	0.02	0.04	0.01	0.01	0.01	0.01	0.07	0.05	0.08	0.08	0.09	0.09
2023	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.09	0.09
2024	0.11	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.10	0.10
2025	0.11	0.02	0.05	0.01	0.01	0.01	0.01	0.09	0.06	0.10	0.10	0.10	0.10
2026	0.11	0.03	0.05	0.01	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2027	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2028	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2029	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.11	0.11	0.11
2030	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.11	0.11	0.12	0.12
2031	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2032	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2033	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2034	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2035	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2036	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2037	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2038	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2039	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.11	0.12	0.12
2040	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2041	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2042	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2043	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2044	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2045	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2046	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2047	0.14	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2048	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2049	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2050	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2051	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2052	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2053	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2054	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
2055	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.13
Levelized (2021–2035)	0.11	0.03	0.05	0.01	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11

Table 167. Motor diesel DRIPE by state (2021 $ per MMBtu)

Year	Zone-on-Zone DRIPE							Zone on Rest-of-Region DRIPE					
	All	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2021	0.10	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.09	0.09
2022	0.11	0.02	0.04	0.01	0.01	0.01	0.01	0.08	0.06	0.09	0.09	0.10	0.10
2023	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.09	0.07	0.10	0.10	0.11	0.11
2024	0.12	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2025	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.07	0.11	0.11	0.12	0.12
2026	0.13	0.03	0.05	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12
2027	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.12	0.12	0.13	0.13
2028	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2029	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.12	0.13	0.13
2030	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.12	0.13	0.13	0.14
2031	0.14	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.08	0.13	0.13	0.14	0.14
2032	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2033	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2034	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2035	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.11	0.09	0.13	0.13	0.14	0.14
2036	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2037	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2038	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2039	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.13	0.14	0.14
2040	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.14	0.14
2041	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.14	0.14
2042	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.14	0.14
2043	0.15	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.15	0.15
2044	0.16	0.03	0.06	0.02	0.02	0.01	0.01	0.12	0.09	0.13	0.14	0.15	0.15
2045	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2046	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2047	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2048	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2049	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2050	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.12	0.09	0.14	0.14	0.15	0.15
2051	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.09	0.14	0.14	0.15	0.15
2052	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.14	0.15	0.15
2053	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.15	0.15	0.15
2054	0.16	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.15	0.16	0.16
2055	0.17	0.04	0.07	0.02	0.02	0.01	0.01	0.13	0.10	0.14	0.15	0.16	0.16
Levelized (2021–2035)	0.13	0.03	0.06	0.02	0.01	0.01	0.01	0.10	0.08	0.11	0.12	0.12	0.12

APPENDIX E: COMMON FINANCIAL PARAMETERS

This appendix presents values for converting nominal dollars to constant 2021 dollars (2021 $) as well as a real discount rate for calculating illustrative levelized avoided costs. These values are used throughout the AESC 2021 study, including in calculations that convert constant to nominal dollars and in levelization calculations. Note also that the *AESC 2021 User Interface* workbook allows users to specify their own discount rate in the calculation of levelized costs.

In summary, we present 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 2021 $ is a long-term inflation rate of 2.00 percent (the same used as in AESC 2018).
- The real discount rate is 0.81 percent (versus 1.34 percent in AESC 2018).

Conversion of nominal dollars to constant 2021 dollars

Unless otherwise stated, all dollar values in AESC 2021 are in 2021 dollars. Therefore, a set of inflators is needed to convert prior year nominal dollars into 2021 $, and a set of deflators to convert future year nominal dollars into 2021$. Those values are presented in Table 168. The inflators are calculated from the GDP chain-type price index published by the U.S. Department of Commerce's Bureau of Economic Analysis.[364] The inflation rate during 2020 has varied from a low of 0.1 percent in May and increased to 1.3 percent in August. Based on this upward trend we model an inflation rate of 1.5 percent for 2020.

Table 168. GDP price index and inflation rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2021$
2000	78.08		1.489
2001	79.79	2.19%	1.457
2002	81.05	1.58%	1.434
2003	82.56	1.86%	1.408
2004	84.78	2.69%	1.371
2005	87.42	3.12%	1.330
2006	90.07	3.03%	1.290
2007	92.49	2.69%	1.257
2008	94.29	1.95%	1.233
2009	95.00	0.76%	1.223

[364] U.S. Department of Commerce, Bureau of Economic Analysis, Table 1.1.9 Implicit Price Deflators for Gross Domestic Product, 8/20/20.

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2021$
2010	96.11	1.17%	1.209
2011	98.12	2.09%	1.185
2012	100.00	1.92%	1.162
2013	101.76	1.76%	1.142
2014	103.64	1.85%	1.121
2015	104.62	0.95%	1.111
2016	105.72	1.05%	1.099
2017	107.71	1.88%	1.079
2018	110.30	2.40%	1.054
2019	112.27	1.79%	1.035
2020	113.95	1.50%	1.020
2021	**116.23**	**2.00%**	**1.000**
2022	118.55	2.00%	0.980
2023	120.92	2.00%	0.961
2024	123.34	2.00%	0.942
2025	125.81	2.00%	0.924
2026	128.33	2.00%	0.906
2027	130.89	2.00%	0.888
2028	133.51	2.00%	0.871
2029	136.18	2.00%	0.853
2030	138.90	2.00%	0.837
2031	141.68	2.00%	0.820
2032	144.51	2.00%	0.804
2033	147.41	2.00%	0.788
2034	150.35	2.00%	0.773
2035	153.36	2.00%	0.758
2036	156.43	2.00%	0.743
2037	159.56	2.00%	0.728
2038	162.75	2.00%	0.714
2039	166.00	2.00%	0.700
2040	169.32	2.00%	0.686
2041	172.71	2.00%	0.673
2042	176.16	2.00%	0.660
2043	179.69	2.00%	0.647
2044	183.28	2.00%	0.634
2045	186.95	2.00%	0.622
2046	190.68	2.00%	0.610
2047	194.50	2.00%	0.598
2048	198.39	2.00%	0.586
2049	202.36	2.00%	0.574
2050	206.40	2.00%	0.563

For the years in our analysis, we use a long-term inflation rate of 2.00 percent. This is the same inflation rate used in the AESC 2018 study. The 2 percent inflation rate is also consistent with the 20-year annual average inflation rate from 2001 to 2019 of 1.93 percent, derived from the GDP chain-type price index. We also examined projections of long-term inflation made by the Congressional Budget Office (CBO) in January 2020 which were 2.00 percent for 2025–2030.[365] In both August and September, the Federal Reserve Board indicated its intent of maintaining a long-term average inflation rate of 2.0 percent. The rate may however vary over the shorter term to address employment problems.[366] Note also that the long-term rate used in the 2020 AEO was 2.30 percent.[367]

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. 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 formula in Equation 17.

Equation 17. Calculating the real discount rate

$$Real\ discount\ rate = \frac{1 + nominal\ discount\ rate}{1 + inflation\ rate} - 1$$

For the nominal discount rate, past AESC studies have generally used 30-year Treasury bills. Because of unusual market conditions (where short-term rates were higher than long-term rates) in AESC 2018 we used a blending of the 10-year and 30-year rates. For this study we return to the use of the 30-year T-Bills. Rates on Treasury bills have declined dramatically in recent years, and have continued to do so to a greater degree during the COVID-19 pandemic (see Figure 62). Through most of 2018, treasury bill rates were about 3 percent, and then declined to about 2.5 percent in 2019. As of July 2020, because of the effects of the COVID-19 pandemic, the 30-year bills were at 1.25 percent and 10-year bills were at 0.62 percent.[368]

Since AESC 2021 requires a long-term value, we use the average of the 30-year T-Bill rates for the two years prior to the COVID-19 pandemic,[369] which is 2.82 percent. This is not greatly different than the

[365] CBO, The Budget and Economic Outlook: Fiscal Years 2020 to 2030, Table 2-1, page 30, January 2020. The same 2025-2030 GDP price index value of 2.0 percent was in the July 2020 update.

[366] Federal Reserve. August 27, 2020. "Federal Open Market Committee Announces Approval of Updates to its Statement on Longer-Run Goals and Monetary Policy Strategy." *Federalreserve.gov.* Available at https://www.federalreserve.gov/newsevents/pressreleases/monetary20200827a.htm.

[367] U.S. EIA. Last accessed March 10, 2021. "Annual Energy Outlook 2020." *Eia.gov.* Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2020&cases=ref2020&sourcekey=0.

[368] As of January 2021, 30-year bills were at 1.87 percent and 10-year bills were at 1.12 percent. These are not substantially different enough to warrant altering the results presented here.

[369] From January 2018 through January 2020.

rate of 3.37 percent used In AESC 2018. This results in a nominal discount rate of 2.82 percent. The resultant future nominal price indices are shown in shown in Table 169.

Figure 62. Recent treasury bill rates at the time of AESC 2021's input assumption development

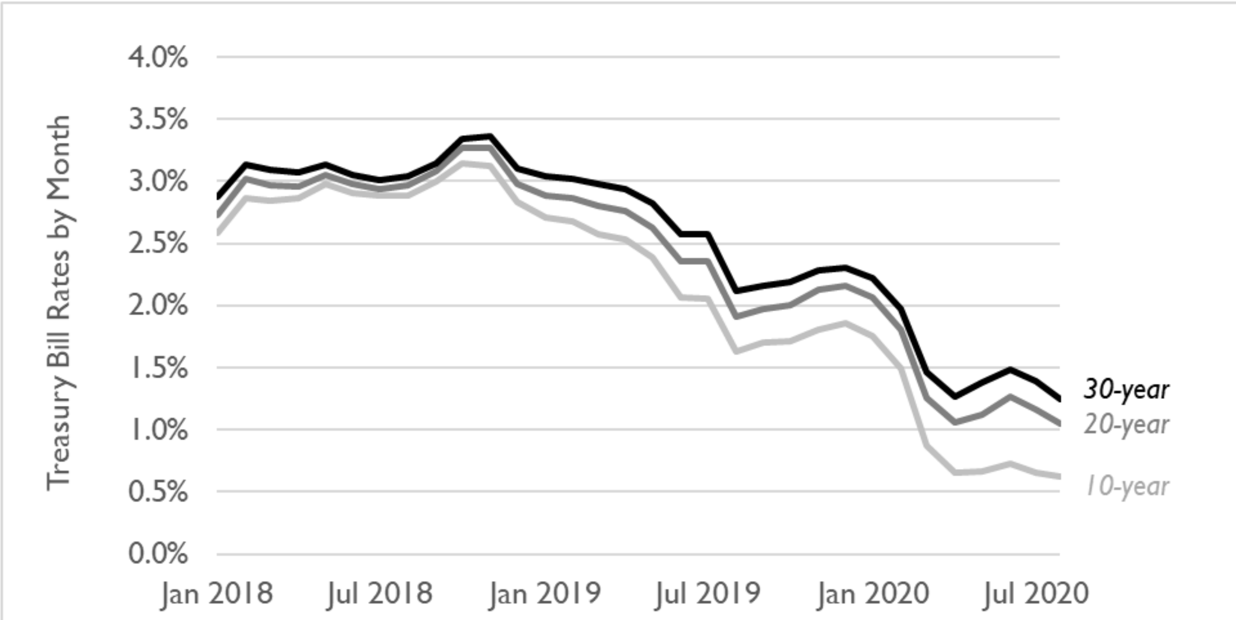


Table 169. Composite nominal rate calculation

Year	Rate	Index	Year	Rate	Index
2021	2.82%	1.000	2039	2.82%	1.650
2022	2.82%	1.028	2040	2.82%	1.697
2023	2.82%	1.057	2041	2.82%	1.745
2024	2.82%	1.087	2042	2.82%	1.794
2025	2.82%	1.118	2043	2.82%	1.845
2026	2.82%	1.149	2044	2.82%	1.897
2027	2.82%	1.182	2045	2.82%	1.950
2028	2.82%	1.215	2046	2.82%	2.005
2029	2.82%	1.249	2047	2.82%	2.062
2030	2.82%	1.285	2048	2.82%	2.120
2031	2.82%	1.321	2049	2.82%	2.180
2032	2.82%	1.358	2050	2.82%	2.242
2033	2.82%	1.397			
2034	2.82%	1.436			
2035	2.82%	1.476			
2036	2.82%	1.518			
2037	2.82%	1.561			
2038	2.82%	1.605			

Notes: A nominal rate of 2.82 percent used throughout the period.

AESC 2021 requires the calculation of illustrative levelized avoided costs expressed in 2021$ for various intervals using the identified real discount rate. Note that the *AESC 2021 User Interface* workbook allows readers of AESC 2021 to input their preferred discount rate to calculate levelized avoided costs.

The real discount rate formula produces a rate of 0.81 percent, which appears reasonable for calculations of levelized costs through periods as long as 30 years.[370] This is lower than the AESC 2018 rate of 1.34 percent and significantly lower than the AESC 2015 rate of 2.43 percent. But as discussed above, the longer-term nominal return rates have declined considerably. We thus rely on a real discount rate of 0.81 percent. A lower discount rate means that future costs and savings will have greater effects on the net present value calculations. Table 170 presents a summary of our findings.

Table 170. Comparison of real discount rate estimates

	AESC 2018	Treasury Bill Method *8/20/2020*	Congressional Budget Office *Jan-20*	Congressional Budget Office *Jul-20*	AESC 2021
Long-term nominal rate	3.37%	1.05%	3.00%	2.60%	**2.82%**
Source	Composite of 10 and 30-year Treasury rates	30-year T-Bills with maturities 2030–2049	Forecast: 10-year Treasury notes 2025–2030	Forecast: 10-year Treasury notes 2025–2030	**30 Year T-Bills Jan 2018–Jan 2020**
Inflation Rate	2.00%	2.00%	2.00%	2.00%	**2.00%**
Source	Above historical average of 1.88%, but below AEO 2017 projection of 2.1%; same as CBO forecast	Slightly above historical average, but greater than the long-term rate	Core PCE Price Index 2025–2030	Core PCE Price Index 2025–2030	**Above historical average of 1.88%, but below AEO 2020 projection of 2.3%; same as CBO forecast**
Resulting long-term real discount rate	1.34%	-0.93%	0.98%	0.59%	**0.81%**

Sources: January 2020 CBO rate is taken from "The Budget and Economic Outlook: Fiscal Years 2020 to 2030," Congressional Budget Office, January 2020, Table 2-1. July 2020. CBO rate is taken from An Update to The Budget and Economic Outlook: Fiscal Years 2020 to 2030*, Congressional Budget Office, July 2020, Table 1.*

[370] This is the standard rate conversion equation used widely and in all previous AESC studies.

Considerations given the COVID-19 pandemic

The effects of the COVID-19 pandemic have greatly affected the U.S. economy. The most significant changes have been declines in employment and economic activity. The effects also show up in the near collapse of interest rates as reflected in the T-Bills. The inflation rate has been affected very little.

APPENDIX F: USER INTERFACE

The *Avoided Cost User Interface* is an Excel-based document that allows readers of AESC 2021 to examine hour-by-hour energy prices and DRIPE values for each reporting region for 2021 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 2055, using the extrapolation methodology described in Appendix A: *Usage Instructions*.

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 *AESC 2021 User Interface*, users can develop customized costs using the following selectable options:

- **Time period:** The interface provides energy and DRIPE values modeled from 2021 through 2035 and extrapolated through 2055.
- **Levelization period:** Users can view costs levelized using the standard levelization periods (10-year, 15-year, and 30-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 (including reporting regions not included in Appendix B).
- **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”)
- **Counterfactuals:** Users may create avoided costs for each of the four AESC counterfactuals.

APPENDIX G: MARGINAL EMISSION RATES AND NON-EMBEDDED ENVIRONMENTAL COST DETAIL

This appendix presents the modeled emission rates for CO_2 and NO_X in the non-electric sectors (Table 171) and in the electric sector (Table 172). We also present the "RE Factor" in Table 173, which is calculated based on the modeling results and the algorithm described in Section 8.3: *Applying non-embedded costs*. This RE Factor may be applied to the marginal emission rates in Table 172 to determine final marginal emission rates for each state.

Users of AESC 2021 must make a determination for which non-embedded costs are most applicable to their own policy context. For illustrative purposes, Table 174 through Table 176 depict the electric and non-electric non-embedded costs assuming the New England marginal abatement cost derived from electric sector technologies (see Section 8.1: *Non-embedded GHG costs*), under Counterfactual #1 for Massachusetts (as an example state). Users of AESC 2021 may utilize the *AESC 2021 User Interface* to generate analogous tables for each of the non-embedded costs described in Section 8.1: *Non-embedded GHG costs*, for each counterfactual, for each state. These tables account for the removal of embedded costs (RGGI for all states, plus costs associated with 310 CMR 7.74 and 7.75 for Massachusetts).

Note that the avoided costs described in Table 174 through Table 176 are already included in Appendix B. These should not be added, and they are shown here for informational purposes only.

Table 171. Marginal emission rates for non-electric sectors

Fuel	Sector	CO_2	NO_X
Natural Gas	Residential	117	0.092
	Commercial	117	0.098
	Industrial	117	0.098
Distillate fuel oil	Residential	161	0.129
	Commercial	161	0.171
	Industrial	161	0.171
B5 Biofuel	All	153	0.129
B20 Biofuel	All	129	0.129
Kerosene	All	159	0.129
LPG	All	139	0.014
RFO	All	173	0.171
Transportation Diesel	All	161	0.717
Gasoline	All	157	0.124
Wood	All	zero	0.341
Wood & Waste	All	zero	0.355

Sources: CO_2 emissions rates from https://www.eia.gov/environment/emissions/co2_vol_mass.php; NOX emissions rates from EPA, AP 42, Fifth Edition, Volume I. Chapter 1: External Combustion Sources, available at https://www3.epa.gov/ttn/chief/ap42/ch01/index.html; Derived from the National Transportation Statistics tables of the Bureau of Transportation Statistics of the US Department of Transportation. Available at https://www.bts.gov/product/national-transportation-statistics. See Tables 1-35, 4-43, and 4-6M.
Notes: Some emissions rates do not vary by sector or geography and are consistent across years. NO_X emission rates for transportation diesel and gasoline are shown for national averages of all vehicles on the road.

Table 172. Modeled short-term electric sector marginal emissions rates (lb per MWh)

	CO_2				NO_X			
	Winter		Summer		Winter		Summer	
	On Peak	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*	*On Peak*	*Off Peak*
2021	756	791	779	799	0.09	0.21	0.14	0.11
2022	740	752	729	813	0.10	0.09	0.14	0.11
2023	732	826	663	932	0.09	0.08	0.11	0.09
2024	791	869	767	967	0.10	0.08	0.12	0.10
2025	796	881	812	966	0.07	0.07	0.12	0.10
2026	756	878	772	939	0.07	0.07	0.11	0.09
2027	682	824	760	930	0.07	0.08	0.11	0.10
2028	686	735	764	822	0.08	0.07	0.12	0.09
2029	702	718	753	794	0.08	0.07	0.11	0.08
2030	636	669	732	760	0.06	0.06	0.09	0.07
2031	648	692	723	768	0.06	0.06	0.09	0.07
2032	644	720	686	774	0.06	0.06	0.09	0.07
2033	652	702	737	788	0.06	0.06	0.08	0.07
2034	678	693	752	770	0.06	0.06	0.08	0.07
2035	691	690	761	793	0.06	0.05	0.07	0.06

We assume all four counterfactuals feature the same marginal emission rates.

Table 173. RE Factor

	CT	MA	ME	NH	RI	VT
2021	0%	0%	0%	1%	0%	8%
2022	0%	0%	0%	1%	0%	9%
2023	0%	0%	0%	1%	0%	11%
2024	0%	0%	0%	1%	0%	12%
2025	0%	0%	0%	1%	0%	13%
2026	0%	0%	0%	1%	0%	14%
2027	0%	0%	0%	1%	0%	16%
2028	0%	0%	0%	1%	0%	17%
2029	0%	0%	0%	1%	0%	18%
2030	0%	0%	0%	1%	0%	19%
2031	0%	0%	0%	1%	0%	21%
2032	0%	0%	0%	1%	0%	22%
2033	0%	0%	0%	1%	0%	22%
2034	0%	0%	0%	1%	0%	22%
2035	0%	0%	0%	1%	0%	22%

Notes: See development methodology in Section 8.3: Applying non-embedded costs*. The RE Factor does not change for different scenarios—see discussion in Chapter 7.* Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies *as to why.*

Table 174. Electric sector non-embedded costs in Counterfactual #1, WCMA (2021 $ per kWh)

	CO_2				NO_X			
	Winter *On Peak*	Summer *Off Peak*	Winter *On Peak*	Summer *Off Peak*	Winter *On Peak*	Summer *Off Peak*	Winter *On Peak*	Summer *Off Peak*
2021	0.0695	0.0728	0.0717	0.0735	0.0007	0.0015	0.0010	0.0008
2022	0.0575	0.0584	0.0567	0.0632	0.0008	0.0006	0.0010	0.0008
2023	0.0582	0.0657	0.0527	0.0741	0.0006	0.0006	0.0008	0.0007
2024	0.0480	0.0527	0.0465	0.0587	0.0007	0.0006	0.0009	0.0007
2025	0.0484	0.0536	0.0494	0.0587	0.0005	0.0005	0.0009	0.0007
2026	0.0444	0.0515	0.0453	0.0551	0.0005	0.0005	0.0008	0.0007
2027	0.0400	0.0483	0.0446	0.0545	0.0005	0.0006	0.0008	0.0007
2028	0.0403	0.0431	0.0449	0.0483	0.0006	0.0005	0.0009	0.0007
2029	0.0384	0.0393	0.0412	0.0434	0.0006	0.0005	0.0008	0.0006
2030	0.0355	0.0374	0.0409	0.0424	0.0004	0.0004	0.0006	0.0005
2031	0.0325	0.0347	0.0362	0.0385	0.0005	0.0004	0.0006	0.0005
2032	0.0293	0.0328	0.0312	0.0353	0.0005	0.0005	0.0006	0.0005
2033	0.0272	0.0293	0.0308	0.0329	0.0004	0.0004	0.0006	0.0005
2034	0.0257	0.0263	0.0285	0.0292	0.0005	0.0004	0.0006	0.0005
2035	0.0235	0.0235	0.0259	0.0270	0.0004	0.0004	0.0005	0.0005
2036	0.0216	0.0214	0.0237	0.0246	0.0004	0.0004	0.0005	0.0005
2037	0.0199	0.0195	0.0217	0.0224	0.0004	0.0004	0.0005	0.0005
2038	0.0183	0.0177	0.0198	0.0205	0.0004	0.0004	0.0005	0.0004
2039	0.0169	0.0162	0.0181	0.0187	0.0004	0.0004	0.0005	0.0004
2040	0.0155	0.0147	0.0166	0.0171	0.0004	0.0004	0.0005	0.0004
2041	0.0143	0.0134	0.0152	0.0156	0.0004	0.0004	0.0005	0.0004
2042	0.0132	0.0122	0.0139	0.0142	0.0004	0.0004	0.0005	0.0004
2043	0.0121	0.0111	0.0127	0.0130	0.0004	0.0004	0.0004	0.0004
2044	0.0112	0.0101	0.0116	0.0118	0.0004	0.0004	0.0004	0.0004
2045	0.0103	0.0092	0.0106	0.0108	0.0004	0.0003	0.0004	0.0004
2046	0.0095	0.0084	0.0097	0.0099	0.0004	0.0003	0.0004	0.0004
2047	0.0087	0.0077	0.0089	0.0090	0.0004	0.0003	0.0004	0.0004
2048	0.0080	0.0070	0.0081	0.0082	0.0004	0.0003	0.0004	0.0004
2049	0.0074	0.0064	0.0075	0.0075	0.0004	0.0003	0.0004	0.0003
2050	0.0068	0.0058	0.0068	0.0068	0.0004	0.0003	0.0004	0.0003
2051	0.0063	0.0053	0.0062	0.0062	0.0004	0.0003	0.0004	0.0003
2052	0.0058	0.0048	0.0057	0.0057	0.0004	0.0003	0.0004	0.0003
2053	0.0053	0.0044	0.0052	0.0052	0.0004	0.0003	0.0003	0.0003
2054	0.0049	0.0040	0.0048	0.0047	0.0004	0.0003	0.0003	0.0003
2055	0.0045	0.0036	0.0044	0.0043	0.0004	0.0003	0.0003	0.0003
Levelized (2021-2030)	0.0482	0.0525	0.0496	0.0574	0.0006	0.0006	0.0009	0.0007
Levelized (2021-2035)	0.0417	0.0451	0.0435	0.0495	0.0005	0.0006	0.0008	0.0006
Levelized (2021-2050)	0.0282	0.0297	0.0295	0.0329	0.0005	0.0005	0.0006	0.0005

Notes: Values are for Counterfactual #1 only. CO_2 price assumes New England marginal abatement cost derived from electric sector technologies. Prices in Massachusetts diverge from other states due to the presence of unique Massachusetts-specific GHG regulations. Other CO_2 prices can be calculated using the AESC 2021 User Interface. *Values shown do not have losses applied.*

Table 175. Non-electric non-embedded costs for CO_2 in Counterfactual #1, all states (2021 $ per MMBtu)

	Natural Gas			Fuel oils							Other Fuels						
				Resi.	Commercial			Industrial			Residential				Industrial	Transportation	
	Residential	Commer-cial	Indus-trial	*Distillate Fuel Oil*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Cord Wood*	*Pellets*	*Kerosene*	*Propane*	*Kerosene*	*Motor Gasoline*	*Motor Diesel*
2021	$11.15	$11.15	$11.15	$15.34	$15.34	$16.49	$15.39	$15.34	$16.49	$15.44	$0.00	$0.00	$15.15	$13.25	$15.15	$14.96	$15.34
2022	$9.47	$9.47	$9.47	$13.03	$13.03	$14.00	$13.06	$13.03	$14.00	$13.11	$0.00	$0.00	$12.86	$11.25	$12.86	$12.70	$13.03
2023	$9.69	$9.69	$9.69	$13.33	$13.33	$14.33	$13.37	$13.33	$14.33	$13.42	$0.00	$0.00	$13.17	$11.51	$13.17	$13.00	$13.33
2024	$7.51	$7.51	$7.51	$10.33	$10.33	$11.10	$10.36	$10.33	$11.10	$10.39	$0.00	$0.00	$10.20	$8.92	$10.20	$10.07	$10.33
2025	$7.54	$7.54	$7.54	$10.37	$10.37	$11.14	$10.40	$10.37	$11.14	$10.44	$0.00	$0.00	$10.24	$8.95	$10.24	$10.11	$10.37
2026	$7.31	$7.31	$7.31	$10.06	$10.06	$10.81	$10.09	$10.06	$10.81	$10.13	$0.00	$0.00	$9.94	$8.69	$9.94	$9.81	$10.06
2027	$7.33	$7.33	$7.33	$10.09	$10.09	$10.84	$10.12	$10.09	$10.84	$10.15	$0.00	$0.00	$9.96	$8.71	$9.96	$9.83	$10.09
2028	$7.36	$7.36	$7.36	$10.13	$10.13	$10.89	$10.16	$10.13	$10.89	$10.20	$0.00	$0.00	$10.01	$8.75	$10.01	$9.88	$10.13
2029	$6.92	$6.92	$6.92	$9.52	$9.52	$10.23	$9.55	$9.52	$10.23	$9.58	$0.00	$0.00	$9.40	$8.22	$9.40	$9.28	$9.52
2030	$7.07	$7.07	$7.07	$9.73	$9.73	$10.46	$9.76	$9.73	$10.46	$9.79	$0.00	$0.00	$9.61	$8.40	$9.61	$9.49	$9.73
2031	$6.43	$6.43	$6.43	$8.84	$8.84	$9.50	$8.87	$8.84	$9.50	$8.90	$0.00	$0.00	$8.73	$7.63	$8.73	$8.62	$8.84
2032	$5.92	$5.92	$5.92	$8.15	$8.15	$8.75	$8.17	$8.15	$8.75	$8.20	$0.00	$0.00	$8.05	$7.03	$8.05	$7.95	$8.15
2033	$5.50	$5.50	$5.50	$7.57	$7.57	$8.14	$7.59	$7.57	$8.14	$7.62	$0.00	$0.00	$7.48	$6.54	$7.48	$7.38	$7.57
2034	$5.09	$5.09	$5.09	$7.00	$7.00	$7.52	$7.02	$7.00	$7.52	$7.05	$0.00	$0.00	$6.91	$6.05	$6.91	$6.83	$7.00
2035	$4.66	$4.66	$4.66	$6.42	$6.42	$6.89	$6.44	$6.42	$6.89	$6.46	$0.00	$0.00	$6.34	$5.54	$6.34	$6.26	$6.42
2036	$4.29	$4.29	$4.29	$5.91	$5.91	$6.35	$5.93	$5.91	$6.35	$5.94	$0.00	$0.00	$5.83	$5.10	$5.83	$5.76	$5.91
2037	$3.95	$3.95	$3.95	$5.44	$5.44	$5.84	$5.46	$5.44	$5.84	$5.47	$0.00	$0.00	$5.37	$4.70	$5.37	$5.30	$5.44
2038	$3.64	$3.64	$3.64	$5.01	$5.01	$5.38	$5.02	$5.01	$5.38	$5.04	$0.00	$0.00	$4.95	$4.32	$4.95	$4.88	$5.01
2039	$3.35	$3.35	$3.35	$4.61	$4.61	$4.95	$4.62	$4.61	$4.95	$4.64	$0.00	$0.00	$4.55	$3.98	$4.55	$4.50	$4.61
2040	$3.08	$3.08	$3.08	$4.24	$4.24	$4.56	$4.26	$4.24	$4.56	$4.27	$0.00	$0.00	$4.19	$3.66	$4.19	$4.14	$4.24
2041	$2.84	$2.84	$2.84	$3.91	$3.91	$4.20	$3.92	$3.91	$4.20	$3.93	$0.00	$0.00	$3.86	$3.37	$3.86	$3.81	$3.91
2042	$2.61	$2.61	$2.61	$3.60	$3.60	$3.87	$3.61	$3.60	$3.87	$3.62	$0.00	$0.00	$3.55	$3.11	$3.55	$3.51	$3.60
2043	$2.41	$2.41	$2.41	$3.31	$3.31	$3.56	$3.32	$3.31	$3.56	$3.33	$0.00	$0.00	$3.27	$2.86	$3.27	$3.23	$3.31
2044	$2.22	$2.22	$2.22	$3.05	$3.05	$3.28	$3.06	$3.05	$3.28	$3.07	$0.00	$0.00	$3.01	$2.63	$3.01	$2.97	$3.05
2045	$2.04	$2.04	$2.04	$2.81	$2.81	$3.02	$2.82	$2.81	$3.02	$2.83	$0.00	$0.00	$2.77	$2.42	$2.77	$2.74	$2.81
2046	$1.88	$1.88	$1.88	$2.59	$2.59	$2.78	$2.59	$2.59	$2.78	$2.60	$0.00	$0.00	$2.55	$2.23	$2.55	$2.52	$2.59
2047	$1.73	$1.73	$1.73	$2.38	$2.38	$2.56	$2.39	$2.38	$2.56	$2.39	$0.00	$0.00	$2.35	$2.05	$2.35	$2.32	$2.38
2048	$1.59	$1.59	$1.59	$2.19	$2.19	$2.35	$2.20	$2.19	$2.35	$2.20	$0.00	$0.00	$2.16	$1.89	$2.16	$2.14	$2.19
2049	$1.47	$1.47	$1.47	$2.02	$2.02	$2.17	$2.02	$2.02	$2.17	$2.03	$0.00	$0.00	$1.99	$1.74	$1.99	$1.97	$2.02
2050	$1.35	$1.35	$1.35	$1.86	$1.86	$2.00	$1.86	$1.86	$2.00	$1.87	$0.00	$0.00	$1.83	$1.60	$1.83	$1.81	$1.86
2051	$1.24	$1.24	$1.24	$1.71	$1.71	$1.84	$1.72	$1.71	$1.84	$1.72	$0.00	$0.00	$1.69	$1.48	$1.69	$1.67	$1.71
2052	$1.14	$1.14	$1.14	$1.57	$1.57	$1.69	$1.58	$1.57	$1.69	$1.58	$0.00	$0.00	$1.55	$1.36	$1.55	$1.54	$1.57
2053	$1.05	$1.05	$1.05	$1.45	$1.45	$1.56	$1.45	$1.45	$1.56	$1.46	$0.00	$0.00	$1.43	$1.25	$1.43	$1.41	$1.45
2054	$0.97	$0.97	$0.97	$1.33	$1.33	$1.43	$1.34	$1.33	$1.43	$1.34	$0.00	$0.00	$1.32	$1.15	$1.32	$1.30	$1.33
2055	$0.89	$0.89	$0.89	$1.23	$1.23	$1.32	$1.23	$1.23	$1.32	$1.24	$0.00	$0.00	$1.21	$1.06	$1.21	$1.20	$1.23
Levelized																	
2021-2030	$8.16	$8.16	$8.16	$11.23	$11.23	$12.07	$11.26	$11.23	$12.07	$11.30	$0.00	$0.00	$11.09	$9.70	$11.09	$10.95	$11.23
2021-2035	$7.32	$7.32	$7.32	$10.07	$10.07	$10.82	$10.10	$10.07	$10.82	$10.13	$0.00	$0.00	$9.95	$8.69	$9.95	$9.82	$10.07
2021-2050	$5.10	$5.10	$5.10	$7.02	$7.02	$7.54	$7.04	$7.02	$7.54	$7.06	$0.00	$0.00	$6.93	$6.06	$6.93	$6.84	$7.02

Notes: CO_2 price assumes New England marginal abatement cost derived from electric sector technologies. Other CO_2 prices can be calculated using the AESC 2021 User Interface.

Table 176. Non-electric non-embedded costs for NO_X in Counterfactual #1, all states (2021 $ per MMBtu)

	Natural Gas			Fuel oils							Other Fuels						
				Resi.	Commercial			Industrial			Residential				Industrial	Transportation	
	Residential	Commer-cial	Indus-trial	*Distillate Fuel Oil*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Cord Wood*	*Pellets*	*Kerosene*	*Propane*	*Kerosene*	*Motor Gasoline*	*Motor Diesel*
2021	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2022	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2023	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2024	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2025	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2026	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2027	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2028	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2029	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2030	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2031	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2032	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2033	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2034	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2035	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2036	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2037	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2038	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2039	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2040	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2041	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2042	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2043	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2044	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2045	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2046	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2047	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2048	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2049	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2050	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2051	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2052	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2053	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2054	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2055	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
Levelized																	
2021-2030	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2021-2035	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27
2021-2050	$0.68	$0.72	$0.72	$0.95	$1.26	$1.26	$1.26	$1.26	$1.26	$1.26	$0.00	$0.00	$0.95	$0.10	$0.95	$0.91	$5.27

APPENDIX H: DRIPE DERIVATION

This appendix describes the derivation of demand reduction induced price effects (DRIPE). This is 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:

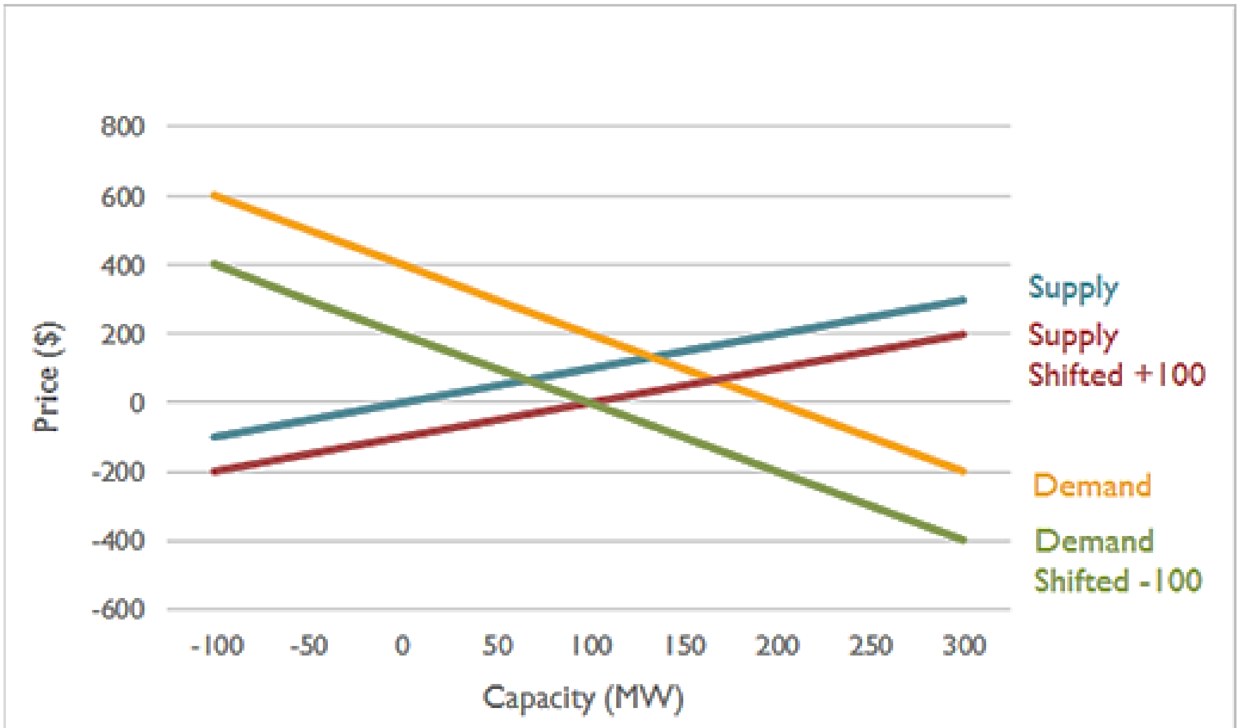
$$b_{demand\ shifted} = b_D - m_D\alpha$$

The shifted Demand function equals:

$$D_{shifted} = b_D - m_D(\alpha + x)$$

Figure 63 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 63. 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 $S_0 = D_{shifted}$

$$m_s x + b_S = b_D - m_D(\alpha + x)$$

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 in Chapter 11: *Value of Improved Reliability*.

Table 177. Matrix of reliability sources

Year	Author	Title	Journal or Source	Document Focus
2018	Cambridge Economic Policy Associates Ltd.	*Study on the Estimation of the Value of Lost Load of Electricity Supply in Europe*	Prepare for Agency for the Cooperation of Energy Regulators. Available at https://www.acer.europa.eu/en/Electricity/Infrastructure_and_network%20development/Infrastructure/Documents/CEPA%20study%20on%20the%20Value%20of%20Lost%20Load%20in%20the%20electricity%20supply.pdf	Reliability Value Assessment – VoLL Methods
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. Available at 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

Year	Author	Title	Journal or Source	Document Focus
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 at 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
2016	Diskin, P.T., Washko, D.M.	*Pennsylvania Electric Reliability Report 2015*	Published by Pennsylvania Public Utility Commission. Available at 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=ODVhZjk4NWQtM2Yy	Reliability Value Assessment- VoLL Country Studies

Year	Author	Title	Journal or Source	Document Focus
			Mi00YjRmLTkxNjktZTcxMjM2NDBmY2Uy&rID=MzQ5MTg3	
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
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. Available at 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 Initiative. 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	Reliability Value VoLL- Annual Total Costs by Sector and Region

Year	Author	Title	Journal or Source	Document Focus
			https://emp.lbl.gov/sites/all/files/report-lbnl-58164.pdf	
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
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 athttps://emp.lbl.gov/sites/all/files/lbnl-54365.pdf	Reliability Value Assessment – VoLL Sector, Region and Duration

APPENDIX J: GUIDE TO CALCULATING AVOIDED COSTS FOR CLEARED AND UNCLEARED MEASURES

This appendix provides a simplified explanation of the methodologies and applications of capacity and capacity DRIPE.[371] It uses a set of illustrative numbers to more simply describe the calculations underlying cleared and uncleared capacity and capacity DRIPE. It accompanies the "AppdxJ" tab of the *AESC 2021 User Interface*, which provides specific numbers for all years, states, and measure lives for the following avoided cost categories:

- Cleared capacity
- Uncleared capacity
- Cleared capacity DRIPE
- Uncleared capacity DRIPE
- Cleared reliability
- Uncleared reliability

This appendix is not intended to substitute the more in-depth explanations provided, which are provided in Chapter 5: *Avoided Capacity Costs*, Section 9.3: *Electric capacity DRIPE*, and Section 11.2: *Value of reliability: Generation component*. A few caveats about this summary:

- This section uses illustrative values only. We have selected values that superficially resemble Massachusetts' avoided costs.[372]
- We simplify some calculation steps for readability but provide footnotes where these steps are more complex in practice.
- We discuss avoided costs as applied to energy efficiency measures, but the avoided costs apply just as easily to demand increases (e.g., from electrification).
- The approaches below describe wholesale avoided costs. Further steps are needed to convert wholesale values to retail values. See Appendix B: *Detailed Electric Outputs* for additional instructions.

[371] This appendix replaces the 2018 version of Appendix J, which focused on "calculating benefits of uncleared capacity and uncleared capacity DRIPE for short- and medium-duration programs." We note that AESC 2018 described there being two separate LFE schedules for long-duration and shorter-duration measures. This is because for measure lives 10 years or greater, the LFE schedule is effectively same for the first 15 years of a measure lifetime (see the last column in Table 43). In the *AESC 2021 User Interface*, we explicitly calculate the uncleared resource effects for 35 different measure lives for the entire study period (2021 through 2055) and thus no longer need to make this simplifying assumption.

[372] Massachusetts is chosen as an example because it constitutes roughly half of New England's electricity demand.

Cleared capacity

Cleared capacity values in AESC represent the avoided cost associated with energy efficiency resources a program administrator has offered and cleared in ISO New England's FCM.

AESC estimates a capacity price for a future delivery year based on the capacity market (e.g., $2 per kW-month, equivalent to $24 per kW-year) as detailed in Chapter 5: *Avoided Capacity Costs*. This value is the avoided cost of cleared capacity. Program administrators then multiply this avoided cost by energy efficiency savings in that year (e.g., 10 MW) to determine the measure's annual benefit. In this example, the annual benefit is $240,000, after converting units. This is $240,000 that ratepayers would not otherwise spend to procure capacity in the capacity market. If the capacity price did not change year-to-year, this measure would provide $240,000 in benefits for every year the illustrative 10 MW measure is in place. The 10 MW measure would provide $1.2 million in benefits if the savings persisted for five years.[373]

Uncleared capacity

A program administrator may choose not to bid all of its energy efficiency portfolio's capacity savings into the capacity market, or it may be possible that a resource does not receive a capacity obligation but is nonetheless built. As a result, the savings from the "uncleared" amounts do not produce direct savings within the capacity market. However, these measures still provide indirect system benefits by impacting ISO New England's forecast of load, which is one of the inputs used to develop prices in the capacity market. See Section 5.2: *Uncleared capacity calculations* for more detail on this avoided cost category.

Because ISO New England's load forecast is based on 15 years of historical data, uncleared measures will eventually impact future load forecasts. However, it takes a few years of sustained savings before the uncleared measures impact the load forecast directly. At that point, the measure's impact can be generally described as a "ramp up" followed by a "fade out." We have created the "load forecast effect" (LFE) schedule to account for this market dynamic. The LFE schedule is a percentage factor that scales a measure's impact on future load forecasts. The percentage varies by calendar year and with the length of time an efficiency measure provides savings (i.e., measure life year).

Importantly, unlike cleared capacity, benefits from uncleared resources must be summed over the study period, rather than the measure life. This is because benefits do not accrue until after the measure has been in effect for a few years, and because benefits continue to accrue for several years after the measure ceases to be active, as the load reduction moves through the 15 years of data used in the ISO load-forecast regression. In AESC we calculate the stream of annual avoided uncleared capacity costs for each measure life within the study period.

[373] This is a simplified example. In practice, program administrators typically discount future benefits and apply transmission and distribution losses to convert wholesale avoided costs to retail costs. Capacity values also typically differ year-to-year. Similar caveats apply to the subsequent sections.

To calculate benefits from uncleared capacity resources, AESC uses the same capacity price calculated in "Cleared capacity," above. We then scale up this capacity price by the reserve margin (e.g., 15 percent) because, by reducing load, uncleared resources avoid the need to purchase additional supply reserves.[374] We further adjust the resulting value to account for the delayed impact on the load forecast (i.e., the LFE). If we now assume that the 10 MW measure from our above example is uncleared, then the uncleared capacity avoided cost is equal to the product of (a) the capacity price at $24 per kW-year, (b) one plus the reserve margin or 1.15, and (c) the LFE (which varies by year and measure life). For years when the LFE is 100 percent, the resulting avoided cost is $27.6 per kW-year. For a 10 MW measure, this implies benefits in that year of $276,000. Because the LFE varies over time, undiscounted lifetime benefits are $1.4 million.

Viewed in isolation, uncleared capacity resources have a larger value than cleared capacity resources. This is because the cleared resources only provide benefits in the years that the measure is active and participating in the capacity market, whereas uncleared resources provide benefits (even at a reduced level) for several years after the measure ceases to provide savings. Uncleared capacity resources are also larger because they include an avoided reserve margin. Because many of the uncleared capacity benefits accrue in the mid- to far-future, but the cleared capacity benefits accrue in the near-term, applying a discount rate could cause the uncleared capacity benefit (in this hypothetical example, $1.4 million) to be equal to or perhaps less than the cleared capacity benefit (here, $1.2 million).

Cleared capacity DRIPE

DRIPE describes the phenomenon wherein 1 MW of savings not only avoids a purchased quantity, but also changes the price that all purchasers in the capacity market pay for capacity. Cleared capacity DRIPE, specifically, represents the price effects on the capacity market from measures bid into the capacity market. These effects can be further subdivided into two categories: benefits to consumers within the state where the measure is installed (intrazonal effects) and benefits to consumers outside of the state where the measure is installed (interzonal effects). AESC translates these price effects (which describe how the system's prices change as demand changes) into DRIPE values (which describe the benefits that accrue to any one measure due to this price effect). See Chapter 9: *Demand Reduction Induced Price Effect* for more background on the concept of DRIPE and Section 9.3: *Electric capacity DRIPE* for more details about capacity DRIPE in particular.

Cleared capacity DRIPE is calculated as follows: first, the "price shift" is estimated. The price shift represents how the capacity price would change if 1 fewer MW of capacity were required. It is calculated by examining the supply curves observed by ISO New England, and calculating the slope of

[374] Uncleared measures are effectively "counted" in the demand side of the capacity auction (i.e., within the load forecast). In contrast, cleared measures are effectively treated the same as conventional power plants (i.e., supply), and through the auction require the purchase of some extra amount of capacity to act as a reserve margin. We increase the uncleared capacity benefit by a value equal to one plus the reserve margin to reflect changes on the demand side of the market.

each line segment between each auction round.[375] This price shift is measured in terms of capacity price per unit demand, or $/kW-month per MW. These price shifts are generally very small numbers. For example, the price shift might be $0.001/kW-month per MW, or $0.012/kW-year per MW.[376]

Second, we multiply these price shifts by the capacity requirement for each state because the price effect impacts resources throughout in the FCM, not just the efficiency resources responsible for the price shift. However, we assume that only a subset of these resources are subject to the price shift. Load-serving utilities purchase some amount of their capacity outside of the FCM to mitigate the risk of price volatility in the capacity market—i.e., as a financial hedge. In AESC, we only consider the "unhedged" portion of the capacity requirement that is bought via the capacity market would be impacted by DRIPE effects.[377]

Finally, we apply an annual decay schedule. AESC assumes the price effect fades out over time as retail prices fall (encouraging higher load), existing resources retire, and new potential resources are abandoned. As a result, price effects are fully realized in the year of installation, but completely phased out six years later. The benefit of cleared capacity DRIPE decays over time, but that decay does not change with the efficiency resource's measure life (unlike the LFE schedule used for uncleared capacity and uncleared capacity DRIPE, which changes with the measure life).

If we assume that our example state has 10,000 MW in unhedged capacity requirement, multiplying this by the $0.012/kW-year per MW price effect from above yields a value of $120 per kW-year. Scaled by the decay effect, this value will be $120 per kW-year in years with no decay and $0 per kW-year in subsequent years with full decay. This is then the avoided cost for cleared capacity DRIPE.

As with cleared capacity, the effects of cleared capacity DRIPE should be summed over the measure lifetime, rather than the study period. As our 10 MW measure lasts for five years, we find that it produces undiscounted intrazonal DRIPE benefits of $4.0 million. Assuming our example state's 10,000 MW of unhedged demand is exactly half of the regional unhedged capacity requirement, the interzonal DRIPE benefits are also $4.0 million, without discounting. Total cleared capacity DRIPE benefits are the sum of these two values, or $8.0 million.

Uncleared capacity DRIPE

Uncleared capacity DRIPE is the price-shifting benefit that accrues to measures not bid into ISO New England's FCM. Even though these measures are outside the capacity market, they impact the load

[375] We assume that all future supply curves have the same shape as the most recent capacity auction, but shifted to account for changes in supply. In AESC 2021, this is FCA 15.

[376] Price shifts may change year-to-year as the corresponding year's capacity price changes position on the supply curve.

[377] In practice, over a long enough period, prices paid for hedged capacity ought to converge to the market price. Because our estimates of DRIPE exclude this hedged amount, they can be considered a conservative estimate.

forecast inputs, and thus provide uncleared capacity DRIPE benefits. As with cleared capacity DRIPE, there are both intrazonal and interzonal benefits.

For the most part, uncleared capacity DRIPE is calculated the same as cleared capacity DRIPE. We begin with a price shift observed from the latest FCA (e.g., $0.0012/kW-year per MW), which is then multiplied by a zone's unhedged capacity requirement (e.g., 10,000 MW). This $120 per kW-year result is the avoided cost. But there are two key differences compared to cleared capacity DRIPE.

1. First, uncleared capacity DRIPE utilizes an LFE schedule. For uncleared capacity DRIPE, we assume the load forecast and thus the capacity market gradually incorporates the impacts of uncleared load reductions (just like with uncleared capacity). This effect persists for some period before the market readjusts, and the DRIPE benefit fades out. This LFE schedule is based on the one used for uncleared capacity, but is adjusted to reflect a decay in DRIPE benefits over time. This is the same decay schedule used for capacity DRIPE. As with uncleared capacity, this LFE schedule varies depending on measure lifetime.
2. Second, because uncleared capacity DRIPE results from a reduction in the load forecast rather than the addition of capacity, we multiply these benefits by a factor of one plus the reserve margin.

The annual intrazonal uncleared capacity DRIPE is equal to the product of (a) the price shift in that year, (b) the zone's unhedged capacity requirement for that year, (c) one plus the reserve margin, and (d) that year's LFE value. Interzonal uncleared capacity DRIPE is calculated the same way but uses the regional unhedged capacity requirement, less the unhedged capacity requirement for the zone in question.

As with uncleared capacity, uncleared capacity DRIPE benefits are summed over the study period (rather than the measure life), as benefits continue to accrue years after the measure has been installed and expires.

In our continued example, undiscounted intrazonal uncleared capacity DRIPE benefits are $3.7 million, while interzonal uncleared capacity DRIPE benefits are also equal to $3.7 million. Total uncleared capacity DRIPE benefits are $7.5 million.

Cleared reliability

The operation of the ISO New England capacity market increases 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.

To calculate cleared reliability benefits, we first estimate four values:

- First, VoLL is the cost experienced by customers during an outage. It is determined through a review of the literature. In AESC 2021, we estimate this value at $73 per kWh.

- Second, we estimate the change in MWh of reliability benefits per megawatt of reserve. This is calculated by observing the slope of the demand curve used in the FCA at the point of the clearing price. A typical value might be 0.2 MWh per MW.
- Third, we derate reliability benefits based on the fact that bidding in an additional MW into the FCA at $0 per kW-month price shifts the supply curve to the right and shifts out some smaller amount of capacity that would otherwise have cleared. As a result, the amount of cleared supply increases by just a fraction of the additional supply. This value is determined by examining the percentage difference in slopes of the demand curve and supply curve at the point of the clearing price. A typical value might be 20 percent.
- Finally, we assume a decay effect. We use the same decay effect that is applied to cleared capacity and uncleared capacity due to similar expected dynamics in market response.

We then multiply these four values against one another to estimate the avoided cleared reliability cost in each year the resource is active. Cleared reliability benefits do not differ based on measure life.

Using the same example as above (a 10 MW measure with a five-year lifetime), we would expect cleared reliability benefits of about $0.01 million. Reliability benefits are much smaller than benefits provided by other avoided cost categories.

Uncleared reliability

Resources that do not clear in the capacity market may still provide a reliability benefit. Some resources that do not clear the FCA 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. They may also be available to assume the capacity obligations of resources that unexpectedly retire or otherwise become unavailable. In addition, resources that do not clear in the capacity market or immediately affect the load forecast will increase reserve margins and contribute to improved reliability.

To calculate uncleared reliability benefits, we first estimate five values:

- First, just as with cleared reliability, we utilize a VoLL. The VoLL in AESC 2021 is $73 per kWh.
- Second, just as with cleared reliability, we estimate the change in MWh of reliability benefits per megawatt of reserve. A typical value might be 0.2 MWh per MW.
- Third, we gross up benefits to reflect the reserve margin, as these resources are not resources bid into the capacity market and thus reduce supply.
- Fourth, we assume that reliability has a phased effect. Measures provide a reliability benefit as soon as they are installed. This benefit persists for a period of time then fades out.

- Fifth, we assume a separate decay effect that reflects the fact that after a period of time, all the of the reliability benefits will have been captured in the load forecast.

We then multiply these five values against one another to estimate avoided uncleared reliability costs. Uncleared reliability differs from the other uncleared avoided cost categories in two ways:

- Unlike uncleared capacity and uncleared capacity DRIPE, uncleared reliability benefits are summed over the years in which the measure is active, rather than the entire study period. This is similar to how avoided costs are summed for cleared reliability and most other avoided cost categories.
- Uncleared reliability benefits do not differ based on measure life.

Using the same example as above (a 10 MW measure with a five-year lifetime), we would expect cleared reliability benefits of about $0.8 million. Generally speaking, uncleared effects are greater than cleared effects because they are not impacted by the net increase in cleared supply variable (which only affects resources that clear the market).

Applying these values

For a portfolio of measures, a program administrator may bid only a share of its capacity savings into the capacity market. In these situations, the program administrator should split the cleared and uncleared savings and calculate benefits accordingly. In our example, if a program administrator bids into the capacity market 50 percent of its 10 MW portfolio of measures, it would provide $600,000 in undiscounted cleared capacity benefits and $690,000 in uncleared capacity benefits (e.g., each of the values calculated above is halved). Likewise, the portfolio of measures provides $4.0 million in cleared capacity DRIPE benefits and $3.7 million in uncleared capacity DRIPE benefits (again, the above values are halved). Reliability benefits are much smaller: this example would yield cleared reliability benefits of $0.05 million and uncleared reliability benefits of $0.4 million.

In practice, (a) measures have different measure lives, (b) each of these avoided cost categories have different decay or LFE schedules, (c) values change over time, and (d) program administrators utilize a discount rate. As a result, program administrators must take a weighted average by measure-life year over the study period, not calendar year. Separate cost streams for cleared capacity, uncleared capacity, cleared capacity DRIPE, uncleared capacity DRIPE, cleared reliability, and uncleared reliability should be calculated independently for each cleared or uncleared MW (or share of MW).

Capacity vs. capacity DRIPE

At first glance, capacity DRIPE benefits may appear surprisingly large relative to capacity benefits. But, changing the price of capacity is a high-value action, because it reduces the cost of procuring capacity for all resources in the system, not just the energy efficiency resources instigating the price change.

For example, assume total unhedged capacity cleared in New England is 20,000 MW, all of which clears at $2 per kW-month. This implies a total annual market value is $480 million. If our 10 MW measure were entirely bid into the capacity market, it would produce $0.24 million in capacity benefits in one year. This is about 0.05 percent of the market's total value, and represents a one-for-one switch between one type of capacity (energy efficiency) for another kind (e.g., a conventional fossil resource).

But, because of price-shifting effects, the cleared measure also lowers the price that other market participants pay for the 20,000 MW. By lowering the price for all 20,000 MW, this measure produces annual cleared capacity DRIPE benefits of $2.4 million, or 0.5 percent of the $480 million total market value (e.g., one order of magnitude larger than the capacity benefit).

These are both small numbers, relative to the size of the market. But because the DRIPE effect is multiplied across 20,000 MW, rather than just 10 MW, the final benefit is larger.

Scaling factor for uncleared resources

Energy efficiency measures generally save energy according to a consistent pattern throughout a year (i.e., its load shape) because they perform the same functions as the less efficient technology while using less energy. Alternatively, demand response resources are designed to provide savings during specific time periods depending on grid characteristics that vary by year, day, and hour. Demand response resources are often subject to customer responsiveness, which can fluctuate with a customer's annual participation in a demand response program and with each demand response event called. As a result, demand response resources typically have shorter and more variable durations, both in terms of measure lives and annual hours of operation. Because of this variability, uncleared measures may not have a "full" effect on the load forecast. This implies that their uncleared benefits should be scaled according to how frequently the measure is expected to operate (and, as a result, impact the load forecast).

To account for demand response's limited impact on the load forecast, AESC recommends that program administrators apply a scaling factor that adjusts uncleared capacity, uncleared capacity DRIPE, and uncleared reliability benefits. The scaling factor is a measure-specific percentage multiplier that should be estimated based on a demand response program's design, implementation, and participant responsiveness. See text in the following section, Appendix K: *Scaling Factor for Uncleared Resources*, and the accompanying workbook titled "Appendix K.xlsx" for more information on how to calculate this scaling factor for different measures.

We note that the scaling factor should not be applied to reliability values.

APPENDIX K: SCALING FACTOR FOR UNCLEARED RESOURCES

This appendix repeats text originally found in the April 2019 report titled, "The Effect of Uncleared Capacity Load Reductions on Peak Forecasts." This report was authored by Resource Insight, Inc. with assistance from Synapse Energy Economics, Inc., and was originally commissioned by National Grid as a supplemental study to AESC 2018.[378] This document was accompanied by a "DR Coefficient Calculator" workbook, which program administrators can use to evaluate how uncleared capacity DRIPE benefits should be adjusted for measures that operate in only some hours of the year.[379]

Text and analysis in this appendix have not been updated, with the following exceptions:

- The addition of a "Purpose" section summarizing the intended use of this appendix
- Some edits to text to improve readability and consistency with the rest of the AESC 2021 text
- Cross-references to parts of the main AESC 2021 text
- Several modifications and corrections to the DR calculator

Analytical updates to this document were not scoped within AESC 2021; however, we do not expect these values to be substantially different than those calculated in the original 2019 report because ISO New England's load forecasting techniques have not changed substantially.

Purpose

This document describes the methodology for creating a scaling factor that adjusts the benefits provided by uncleared resources. It also provides a calculator workbook so that program administrators may create this scaling factor for themselves. This workbook is the file titled "Appendix K.xlsx."

It is only for resources that are not expected to provide a capacity benefit throughout the summer period (we focus on summer, because it is summer demand that drives the capacity market). For example, this factor is useful for demand response measures that may only be active some summer days. But it is not applicable to resources like energy efficiency that are assumed to provide savings at a more-or-less consistent level throughout the summer.

Program administrators wishing to use this appendix will want to use the Appendix K workbook to estimate the appropriate scaling factor for their DSM resource. This factor is then multiplied by the

[378] Chernick, P., P. Knight, M. Chang. April 22, 2019. *The Effect of Uncleared Capacity Load Reductions on Peak Forecasts.* Synapse Energy Economics prepared for National Grid. Available at https://www.synapse-energy.com/sites/default/files/The_effect_of_load_reductions_on_peak_forecasts.pdf.

[379] See original version at https://www.synapse-energy.com/sites/default/files/DR_Coefficient_Calculator%20%282%29.pdf.

uncleared capacity or uncleared capacity DRIPE avoided cost (calculated using the *AESC 2021 User Interface*) and the measure's capacity savings and seasonal coincidence factor to provide the final benefit value.[380]

This scaling factor is not applicable to cleared capacity, cleared capacity DRIPE, cleared reliability, uncleared reliability, or any other avoided cost category.

Introduction

This appendix describes our analysis of the effects of load reductions on a varying number of days per year over a varying number of years. This analysis included the construction of a regression model to mimic the ISO New England forecast model and the variation of the historical data to determine the effect of targeted load reductions for the FCAs. We interpret these effects as having an impact on the future value of uncleared capacity and uncleared capacity DRIPE.

Our modeling indicates that a load reduction program that occurs on even a single peak day each summer can affect the load forecast used in the FCA. In most situations, the load forecast will fall more if the historical load is reduced for more days per year or for more years. Regardless of the number of days that a program reduces load annually, the reduction in the load forecast rises steadily for at least eight years. If the program reduces load on less than 55 days, the forecast reduction continues to increase until the program has been running for 12 days. For programs that reduce load on less than 13 days annually, running the program for more years continues to depress the load forecast further, up to the 15 years' worth of historical data that ISO New England uses to develop each load forecast.

This implies that resources that do not provide load reductions on every day of the summer period should have reduced values for uncleared capacity and uncleared capacity DRIPE, relative to the values estimated in the *AESC 2021 User Interface*.

Background

This issue is specific only to uncleared resources.[381] For example, these may include demand response programs, behavioral programs, or rate-design initiatives that are not eligible capacity resources. Although uncleared resources do not receive capacity payments, they reduce the aggregate amount of

[380] We note that there may be certain situations when a dispatchable resource (such as demand response or storage) is cleared in the capacity market, but also performs in such a way that creates uncleared capacity benefits. These additional uncleared benefits are likely to be small, as the most likely the way for them to occur is for a resource to operate for a limited number of hours, during periods that are less important to the formulation of ISO New England's load forecast regression. Calculations to estimate these benefits are complex, dependent on the specific program being analyzed, and may be impossible to calculate without obtaining more specific load regression data from ISO New England. As a result, we do not perform this estimate in AESC 2021. Future editions of this study or follow-up supplemental studies may examine this issue in closer detail.

[381] This includes any resources or portions of resources that are not bid into the FCA or are bid into FCAs but do not clear the auction.

capacity that is required, and hence the price of that capacity, by reducing the ISO New England peak load forecast used in the FCA for that year (see Section 5.2: *Uncleared capacity calculations* for a longer discussion of this dynamic).

The quantity and price of the capacity obligations acquired in the FCA of a particular year (year *t*) depend on the forecast prepared in the previous year (*t* – 1). That forecast is built upon a regression analysis constructed from daily historical data from each of the 62 days in July and August for the previous 15 years (*t* – 16 to *t* – 2), which consists of 930 data points.[382] The regression formulation for the forecast may vary from year to year, but appears to consistently include multiple independent variables computed from a weighted temperature-humidity index (WTHI), including an annual time trend times WTHI and the gross energy forecast (before energy efficiency and BTM solar PV).

Although we consulted with ISO New England on its forecast data, ISO New England did not provide us with its proprietary demand model data or any details on the functional form of its regression model, beyond those in the Forecast Data summaries provided on the ISO New England web site.[383] As a result, our analysis reconstructs a proxy ISO New England load forecast. We then use this to quantify the impact different load reductions over different time periods and under different conditions.

The reference regression model

We constructed our proxy for the ISO New England forecast model based on the data used in the 2017 CELT forecast, which was used in FCA 12 to procure capacity for the summer of 2021.[384] Importantly, all of the effects described below for the reference regression model are for load reductions of various numbers of years that would have been used in producing the 2017 CELT forecast for summer 2021, which was the basis for the demand curve used in FCA 12. Other regressions performed using data for other years could provide different results. A one-year load reduction would affect only the 2016 summer peak day(s), a two-year reduction would affect 2015 and 2016, a three-year reduction would affect 2014–2016, and a 15-year reduction would reduce peaks in 2002–2016.

Input data

Since we did not have ISO New England's exact data, we needed to develop a proxy dataset. As a result, our analysis should be interpreted as an estimate of load reduction effects *based upon data and using a model similar* to that currently used by ISO New England. We do not claim that our model is a precise

[382] Discussions with ISO New England after the completion of this supplemental study confirmed that the forecast is solely built on summer peak hours. Winter peak hours are not included.

Knight, P., M. Chang, J. Hall. May 1, 2020. *AESC Supplemental Study Part I: Considering Winter Peak Benefits*. Synapse Energy Economics for Massachusetts Electric Energy Efficiency Program Administrators. Available at https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_I_Winter_Peak.pdf.

[383] This data includes ISO New England's computation of daily WTHI and reconstitution of load for peak-hour energy-efficiency reductions, demand response and OP #4 measures, and behind-the-meter solar output.

[384] FCA 12 was conducted in February 2018 and was the most recent FCA conducted at the time of this analysis.

prediction of future ISO New England forecasts. Since ISO New England's data and its model structure change (at least a little) every year, we cannot anticipate the exact form of the ISO New England load forecast model for any specific future year.

Development of proxy data

First, we made a number of assumptions to generate our proxy historical dataset, which may not necessarily match ISO New England's past and future sources and methodology.

The dependent variable in the regression analysis is the daily gross peak demand. This is the actual daily peak demand, plus the effects of BTM solar PV and energy efficiency programs (referred to as PDR by ISO New England) for both peak demand and energy, as well as the effects of Operation Procedure #4 (OP #4) events and load management on peak (which is available only for the summer and winter peaks). [385, 386] Our understanding is that ISO New England uses a proprietary data service to estimate the output of installed solar capacity in each historical hour, while assuming that every hour's PDR reduction is equal to the PDR resource cleared in that capacity delivery year.

We estimated historical daily gross peak load as the sum of (a) the maximum hourly demand for the day in ISO New England's hourly load data files and (b) the summer peak PV and PDR reported in the ISO New England's 2017 Forecast Data spreadsheet for the year. [387, 388] We computed the gross monthly net energy for load (NEL) by multiplying the historical monthly sum of actual load by the ratio of gross annual energy to net annual energy from the ISO New England 2017 Forecast Data.[389]

We computed the ISO New England temperature-humidity index (THI) for each day (0.5 × dry-bulb temperature + 0.3 × wet-bulb temperature + 15) as the weighted average of the THI's (the "WTHI") from

[385] Actual daily peak demand is available from the ISO New England website.

[386] ISO New England. March 4, 2021. "ISO New England Operating procedure No. 4 – Action During a Capacity Deficiency" Iso-ne.com. Available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

[387] ISO New England. Last accessed March 10, 2021. "Energy, Load, and Demand Reports." *ISO-ne.com.* Available at https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/sys-load-eei-fmt.

[388] CELT 2017 Forecast Data File, Tab 5, WN. CELT 2017 was analyzed, as it was the projection used as the basis of the 2018 AESC Study.

[389] CELT 2017 Forecast Data File, Tab 1, History, Gross ISO-NE Coincident Summer Peak.

eight weather stations around the region.[390] We then computed the WTHI for each day using ISO New England's formula (weights of 10 for today's THI, 5 for yesterday's THI, and 2 for the previous day).[391]

Model specification

We estimated the historical relationship of gross load to WTHI, time, NEL and other variables with an ARIMAX (Auto-Regressive Integrated Moving-Average model with eXogenous variables) regression model.[392] This model incorporates both exogenous variables (e.g., net energy for load, weather) and the autoregressive error terms that ISO New England uses in its regression model. These are summarized in Table 178.

Table 178. Variables used in summer peak model

Variable	Definition
Intercept	Constant Term
PEAK	Daily Peak Load, MW
MA_NEL	12-month Moving Sum Annual Net Energy for Load, GWh
WTHI_SQ	The square of [the 3-day Weighted Temperature-Humidity Index at Peak– 55°]
TIME_WTHI	Year indicator; (2002=11, …, 2016=25) × WTHI
Weekend_WTHI	WTHI for a weekend day, else 0
July_04WTHI	WTHI for July_4, else 0
HOLWTHI	WTHI for a Holiday, else 0
Yr2005	1 if Year=2005; 0 otherwise
Yr2012	1 if Year=2012; 0 otherwise
AR(1)	Correction for autocorrelated error from the previous year
AR(2)	Correction for autocorrelated error from the two years previously

Note: This reproduces the description of the summer peak model in the Peak Definitions in ISO New England's 2017 Regional and State Energy & Peak Model Details, corrected to reflect conversations with the ISO forecasters and the specific model described in the Summer Peak Models tab of the Model Details.[393]

[390] The Notes sheet of the annual *SMD Hourly.xlsx* file provide the following weights for the weather stations: Windsor Locks CT (27.7 percent); Bridgeport CT (7 percent); Boston MA (20.1 percent); Burlington VT (4.6 percent); Concord NH (5.8 percent); Worcester MA (21.4 percent); Providence RI (4.9%); Portland ME (8.5 percent). We used the same weights for all years; we have not been able to confirm whether ISO New England has changed the weights over time, as load (especially summer peak) has increased in northern New England compared to the southern portion of the region.
Iowa State University. March 11, 2021. "Dry Line Over Iowa." *Iastate.org*. Available at https://mesonet.agron.iastate.edu/.

[391] Forecast Modeling Procedure for the 2018 CELT, May 1, 2018, page 9. https://www.iso-ne.com/static-assets/documents/2018/04/modeling_procedure_2018fcst.pdf. Note that this document contains all citations for coefficients and weights used in this analysis.

[392] Statmodels. Last accessed March, 10, 2021. *Statsmodels.org*. Available at https://www.statsmodels.org/devel/generated/statsmodels.tsa.statespace.sarimax.SARIMAX.html.

[393] The ISO New England forecast documentation sometimes refers to gross loads as net of PV and PDR, and the Forecast Modeling Procedure for 2017 CELT describes the composite time variable as using WTHI–55º, while the 2017 Regional and State Energy & Peak Model Details file suggests that WTHI is not reduced by 55º.

Independent variables included:

- Net Energy for Load, grossed up for PV and energy efficiency, over the 12 months ending in the current month (July or August, depending on the data point).
- The 3-day weighted temperature-humidity index (WTHI) for the eight cities used in ISO New England's own modeling of weather (see footnote 390). In our analysis, following the treatment in the ISO New England model, the WTHI variable is used as the square ($[\text{WTHI}–55]^2$), and as various cross terms, such as WTHI × weekend dummies.
- Year × (WTHI–55), where the year index is the calendar year minus 1991.
- Boolean flags (i.e., dummies) for holidays, July 4th, weekends, the years 2005 and 2012, and WTHI times the dummy variables for weekends, holidays and July 4th.[394]

These variables were defined for each July and August day in 2002 through 2016.

Forecast data

Once we developed the regression equation, we required forecast input values for the equation. One such input is a forecast of gross energy for load, which ISO New England provides in its forecast.[395] A second set of inputs entails time trend and binary variables: for time trend, we observe that 2017 is year 26, 2018 is year 27, and so on. For binary variables, the weekend binary equals WTHI on future Saturdays and Sundays, the July 4 and holiday binaries equal WTHI on July 4 each year.

ISO New England's forecasting method does not use a single WTHI value, but instead identifies the highest load for a variety of input conditions:

> Weekly peak load forecast distributions are developed by combining output from the daily peak load models with energy forecasts and weekly distributions of weather variables over 40 years.
>
> The expected weather associated with the seasonal peak is considered to be the 50th percentile of the top 10% of the pertinent week's historical weather distribution. The monthly peak load is expected to occur at the weather associated with the 20th percentile of the top 10% of the pertinent week's weather distribution. The "pertinent week" is the week of the month or season with the most extreme weather distribution. For resource adequacy purposes, peak load distributions are developed for each week of the forecast horizon.[396]

[394] It is unclear why ISO New England included variables for both holidays and July 4th, since the only holiday in the two summer months is July 4th. We used the two redundant variables; collectively, the two dummies should capture the effect of July 4th. It is also not unclear why the years 2005 and 2012 featured Boolean flags.

[395] 2017 Forecast Data File, Tab 6, Monthly NEL.

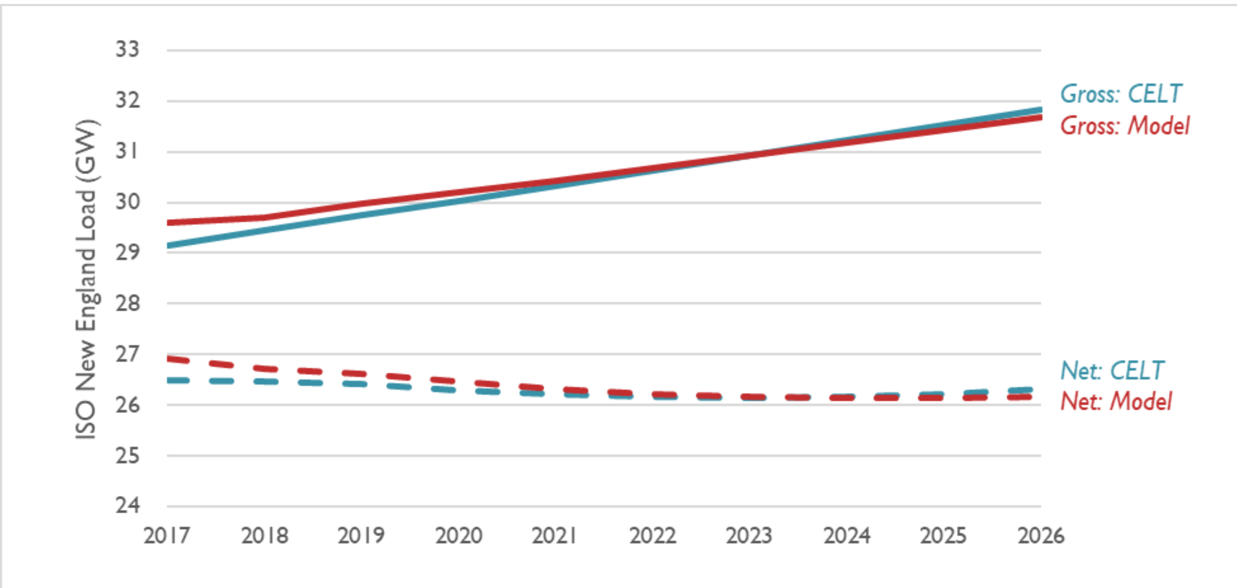
[396] Forecast Modeling Procedure for the 2018 CELT, May 1, 2018, p. 6.

We do not have access to the distributions that ISO New England used in this method, nor do we have a clear operational description of the method. Therefore, we performed a calculation to estimate a value of WTHI that best reproduced the 2017 CELT peak forecast, which turned out be 81.4°.

Base forecast benchmarking

Figure 64 summarizes our modeled Gross and NET 2017 forecast against the 2017 reported Gross and NET CELT forecast. Our modeled forecasted peak demands closely match the ISO's 2017 CELT forecast. Our forecasts for gross peak are within 0.2 percent of the 2017 CELT forecast for 2021, the year for which the 2017 forecast determined the installed capacity requirement.

Figure 64. Comparison of forecasts of gross and net Summer Peak, 2017 CELT and Resource Insight modeled proxy



The effect of load reductions on the forecast

The following sections describe our methodology and findings. We also describe a set of sensitivities that were analyzed to provide robustness for our results.

Structure of reductions

Using our constructed base forecast, we estimated how various load reductions in 2002 through 2016 would have affected the ISO New England load forecast for 2021. Each sensitivity run for the analysis consisted of four steps:

1. Reduce historical gross peak demands on a specified number of summer event days (*d*) for a specified number of years (*y*) by a constant number of MW (ΔL).

2. Estimate new regression model coefficients using the same functional form and the modified historical data.

3. Develop peak demand forecasts for the years 2017–2026 (and most importantly, 2021) using the new coefficients.

4. Compute the ratio (*R)* of the change between forecast peak (ΔF) to the load reduction (ΔL).

The ratio *R* can be thought of as a measure of the efficiency of load reduction in reducing the forecast.

For ΔL, we tested load reductions of 250 MW, 500 MW, and 1,000 MW. We used the same reduction in all the days and all the years adjusted in any particular run.

For *d*, we reduced load on the highest days, from one event day to all 62 summer days per affected year. We tested reductions on the highest-load days and the highest-WTHI days and looked at the effect of imperfect forecasting of peak days.

For *y*, we reduced load on the most recent years, from just one year (2016) to all 15 years 2002–2016.

The effect of lower input values on regression forecasts

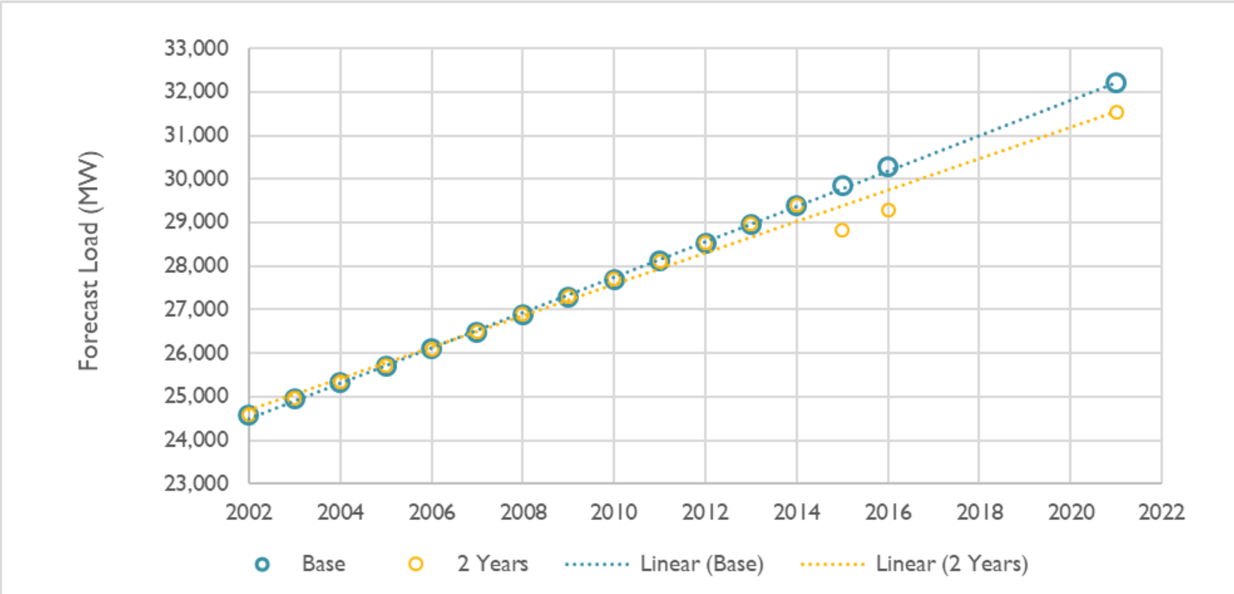
When we began this analysis, we expected that reductions on more days, and reductions in more years, would consistently push down the forecast further. As we discuss in the next section, that is not what we found. Before presenting our results, we will explain how they can arise.

The next four figures show a regression through 15 years of base data. In these examples, we assume a constant 1.5 percent annual growth.[397] In each figure, we show the base historical data, the linear trend line with the base data, the historical data that would have been observed with 1,000 MW reductions in some years, and the regression trend line with the modified data. For each figure, we identify how the change in load impacts the regression and the projection of 2021 load in particular.

The first figure, Figure 65, shows the effect of load reductions in the last two years of data, representing a demand response program operating in 2015 and 2016. The trend line tilts so that the trend is higher than the actual load in the first few years and in the last two years (the two years with demand response reductions), but lower than the input data for 2008–2014. The projection for 2021 is about 700 MW lower than in the base case.

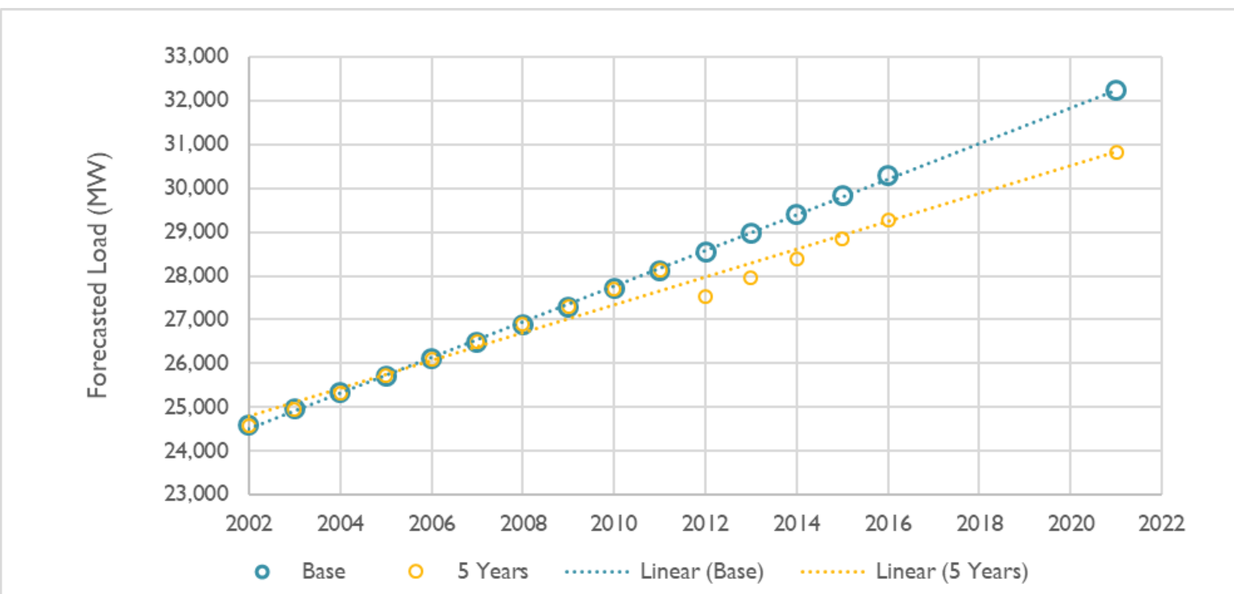
[397] A comparable analysis using weather-normalized loads before PDR and PV for 2002 through 2016 produced very similar results. But, due to a drop in load associated with the 2009-10 Great Recession, it is more difficult to read. We use a simplified example here.

Figure 65. Effect of two years of demand response on the forecast



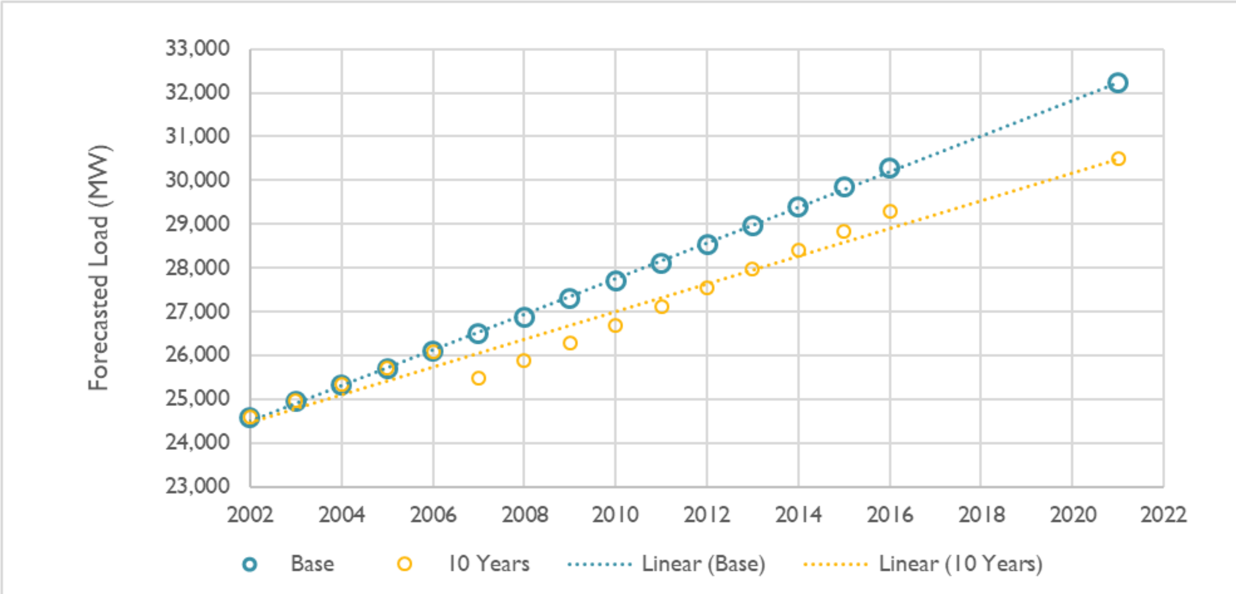
Next, Figure 66 shows the effect of five years of demand response reductions. The trend line with the demand response has tilted further, so that it is almost 1,000 MW below the base-case trend by 2016, and 1,400 MW below the base-case forecast for 2021. The trend line mostly rotates clockwise, rather than moving down, so the change from the base case increases over time and the reduction in the 2021 forecast is substantially larger than the reduction in loads in the five years affected by demand response.

Figure 66. Effect of five years of demand response on the forecast



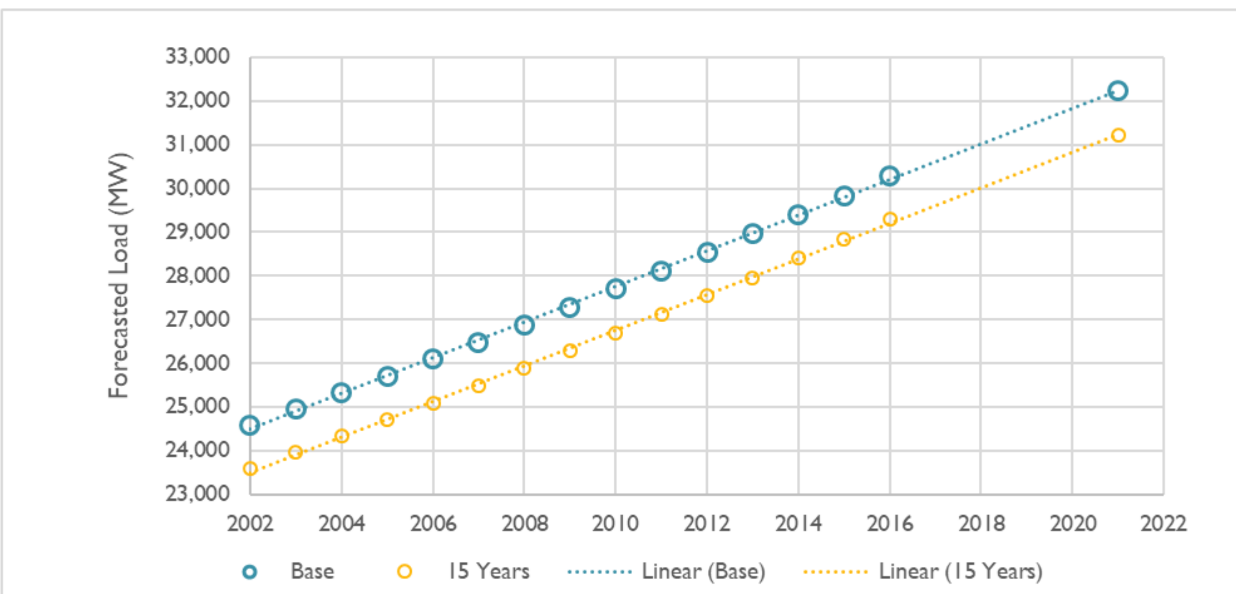
Third, Figure 67 shows the effects of nine years of demand response, which continues the pattern in Figure 66; the forecast for 2021 would be almost 1,800 MW below the base case.

Figure 67. Effect of nine years of demand response on the forecast



Finally, Figure 68 shows that 15 years of 1,000-MW load reductions lowers the trend line by 1,000 MW, while leaving the slope the same as in the base case. The forecast for 2021 is thus 1,000 MW lower than in the base case.

Figure 68. Effect of 15 years of demand response on the forecast



Thus, demand response in some number of the latest years will tend to produce forecast reductions that exceed the annual reductions in the historical data. Beyond some point, additional years of demand response will result in smaller forecast reductions, and once the demand response effect has been in effect for the entire study period, the forecast reduction will equal the reduction in the annual input data.

The same pattern would be expected as the reductions are extended to more of the highest-load days in each year.

Results for reductions on highest-load days

Not surprisingly, we found that the decreases in the forecast peaks based on load reductions varied with (a) the number of days on which load was reduced each year and (b) the number of years of load reductions in the historical load data. Interestingly, we found that the size of the load reduction had essentially no effect on the ratio of forecasted load reduction to historical load reduction, or as we have named it, the ratio *R*. For example, we observe that if load is reduced 100 MW on the five highest-load days in each of the last five summers in the modeling dataset (2012–2016), the forecast for 2021 would be reduced by 24 MW; if the reductions in the historical load were 1,000 MW, the forecast would be reduced by 240 MW.

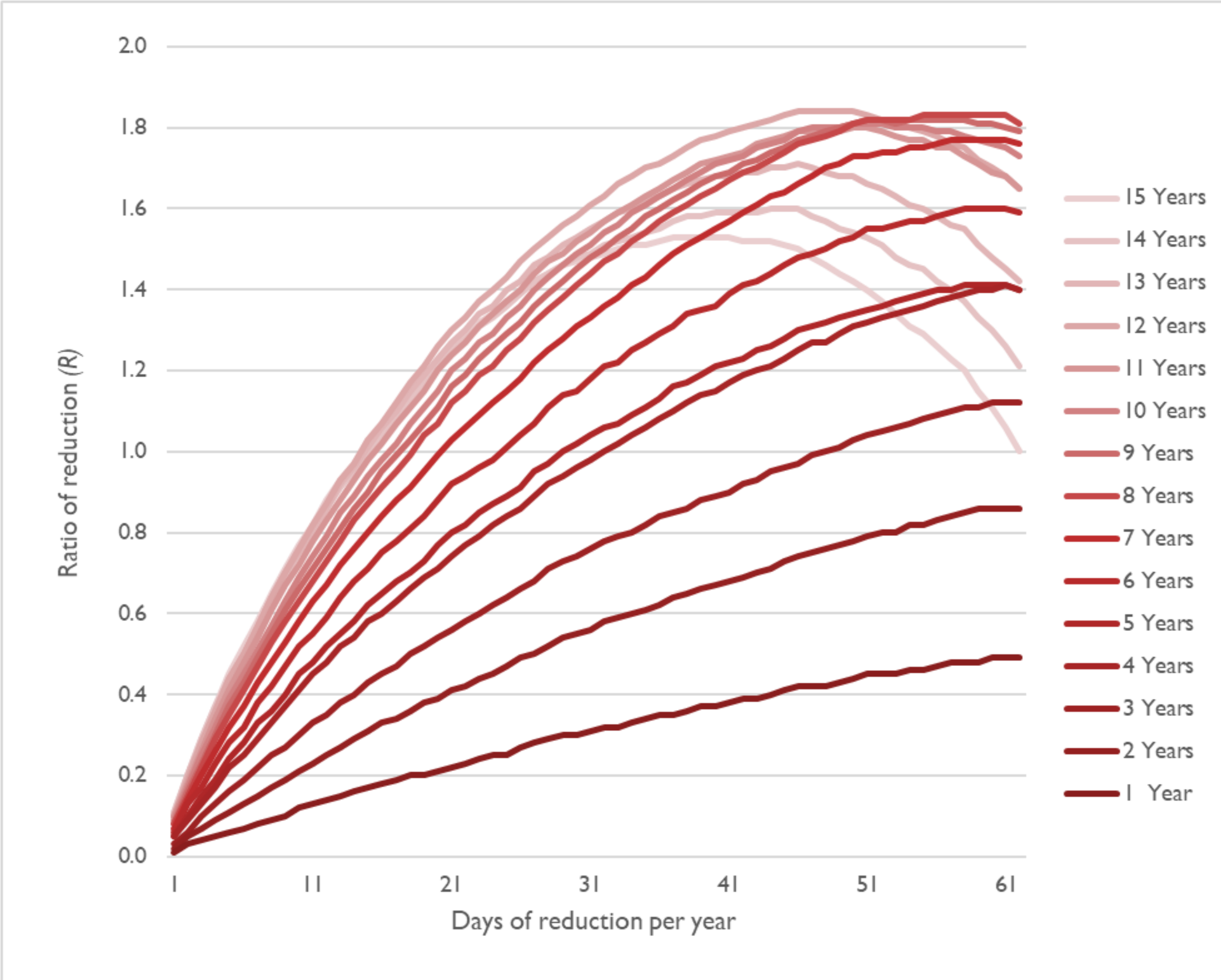
For any duration of a load reduction program, the value of *R* rises with the number of days in which load is reduced, up to at least 35 days. For load reduction programs lasting more than eight years, the value of *R* begins to fall if the number of days reduced exceeds some threshold; at about 55 days for a 9-year program and at about 40 days for a 15-year program.

However, the value of *R* did not vary monotonically with respect to either the number of days or the number of years, and *R* could be more than 1.0, as shown in Figure 69.

For a load reduction program lasting more than two years, reducing load on a large number of days results in $R > 1$, such that the reduction in the load forecast is larger than the reported reduction in the historical load. For a three-year program, *R* peaks at about 1.1 with reductions in 60 days; programs lasting 8 to 12 years have peak *R* above 1.8 for about 50 days of reductions; and a program that reduces load in all 15 years used in the forecast would have a value of *R* over 1.5 for 31 to 46 days of reduction, with *R* falling rapidly for any additional days.

A program that reduces load for all 62 summer days each year for 15 years has an *R* value of exactly 1.0. In effect, such a program would look, for peak-forecasting purposes, like a cleared energy efficiency measure.

Figure 69. Ratio of forecasted load reduction to historical load reduction, various durations

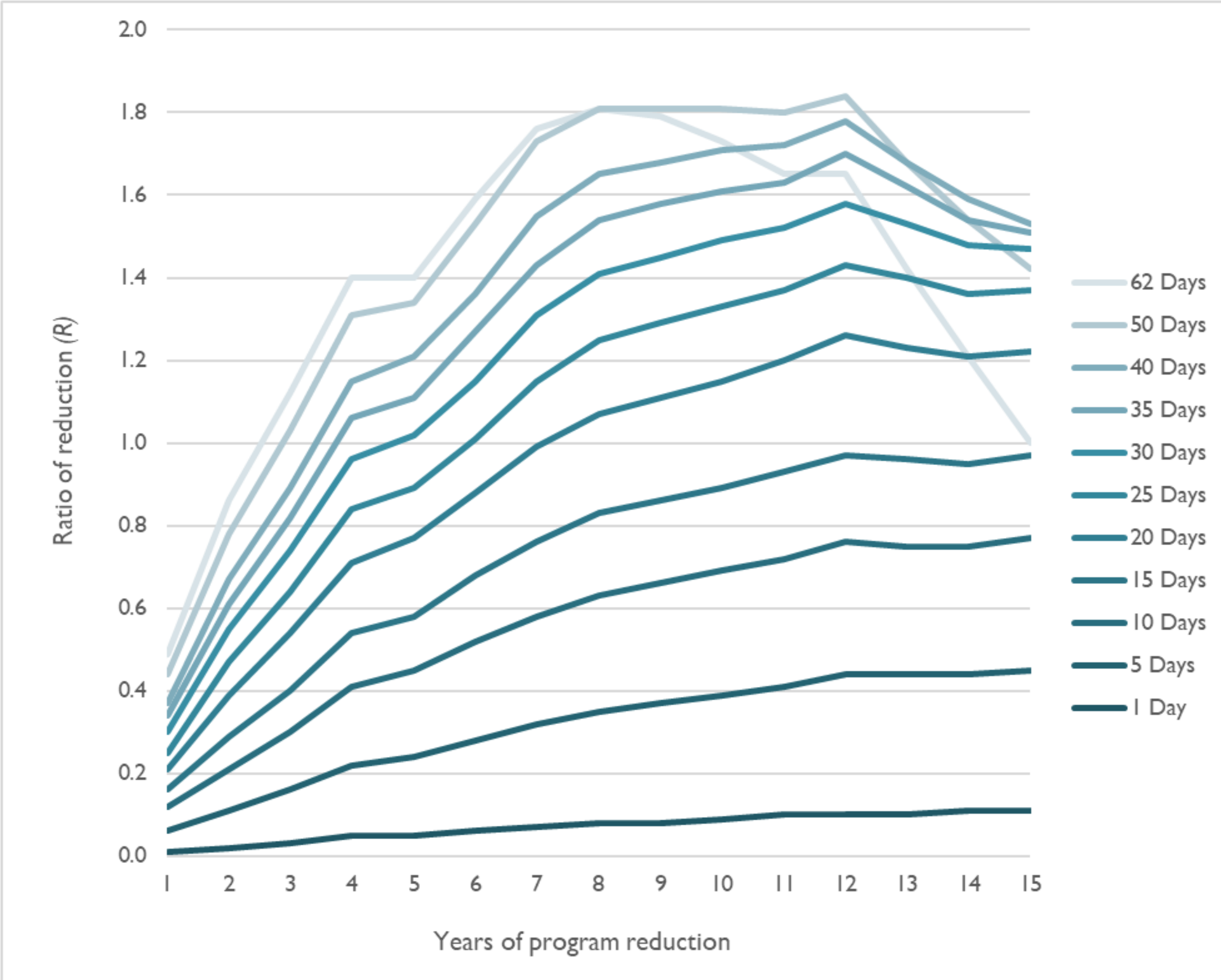


Note: Ratios are shown for 2021 forecasted year.

Figure 70 provides the same data, but with the duration of the reduction in years on the *x* axis and each line representing a number of days of load reduction in each year (essentially swapping the *x* axis and legend in Figure 69). For readability, we present only a subset of days, rather than the full 62.

The horizontal axis in Figure 70 is the number of years that a load reduction has been in place, as of the last year of historical data for the forecast (year *t* – 2). See Subappendix A. Ratio of forecast reduction to load reduction for the *R* values from Figure 69 and Figure 70 numerically.

Figure 70. Ratio of forecast reduction to load reduction, various numbers of peak days per year



Applying the results to demand response screening and valuation

The results in Figure 69 and Figure 70 can be used in at least two ways.

First, they can be used to screen potential demand response programs by modifying the values used for uncleared capacity and capacity DRIPE. For example, a new program that would first reduce load in 2020, for the top ten summer days, would be a one-year reduction in the data for the 2021 forecast, which would be used in the 2022 FCA 16 for the summer of 2025. Since we find that a 10-day program has an *R* value of 0.12, a 200 MW load reduction in 2021 would reduce the forecast peak by 24 MW and produce the DRIPE benefits of that size load reduction. Once the program has run for three years (e.g., 2020–2022), it would create a three-year reduction for the 2023 forecast used in 2024 for FCA 18 for the summer of 2027. The program would have an *R* value of 0.30, so the FCA forecast for 2027 would be reduced by 60 MW. Similarly, if the program continues to run for 15 years, the reduction in the forecast used for FCA 30 would be 154 MW.

Second, the results can be used retrospectively, to evaluate the effect of a program that has been operating. In 2019, a Program Administrator might file results for a 100 MW program that it ran in 2014–2018, reducing load on the top 15 days of each summer. From Subappendix A. Ratio of forecast reduction to load reduction, we would use the 15-day row and estimate that the program reduced the load used in the FCA forecasts by 17 MW in 2018 (for which 2014 was the last year of data used in the forecast), 31 MW in 2019, 43 MW in 2020, and 58 MW in 2021. The sum of the avoided capacity and DRIPE from those years would be benefits of the program.

Sensitivity analysis: Other demand response dispatch approaches

This section describes the results of our analysis under a variety of dispatch and implementation sensitivities, including situations in which demand response is dispatched according to weather or in line with day-ahead forecasts. We also examine situations in which the dispatch of demand response misses some peak days, is performed according to some forecast of load distribution, and in which demand response is dispatched for only a single day each year.

Dispatching according to weather, rather than load

Our main analysis assumes that a demand response program identifies the highest-load days and achieves load reduction on those days. We find that the results are essentially identical for a program that concentrates on reducing load on the days with the worst weather (the highest WTHI values), even though those are slightly different from the highest load days.

Dispatching demand response with day-ahead forecasts

We find that the results are also very similar if targeting of the demand response is imperfect, such that the program is activated on some days that are not in the *d* highest days.[398] For example, the program administrator may call an event on a day that looks like it will be one of the top *d* days for the summer, but it may turn out to have an actual load lower than expected. Or, it may turn out that there are more higher-load days that occur later in that summer, after the program administrator has called as many days as is allowed by the tariff or contracts.[399]

Figure 71 shows the accuracy of demand response program dispatch that is called when the day-ahead peak load is expected to be one of the highest *d* days. These results factor in the optimistic assumption that the program administrator has perfect information about the highest loads for the current summer but not when those highest load days will occur. With this assumption, programs allowing for 5 to 20 days of load reductions would catch 90 percent of the intended control days.

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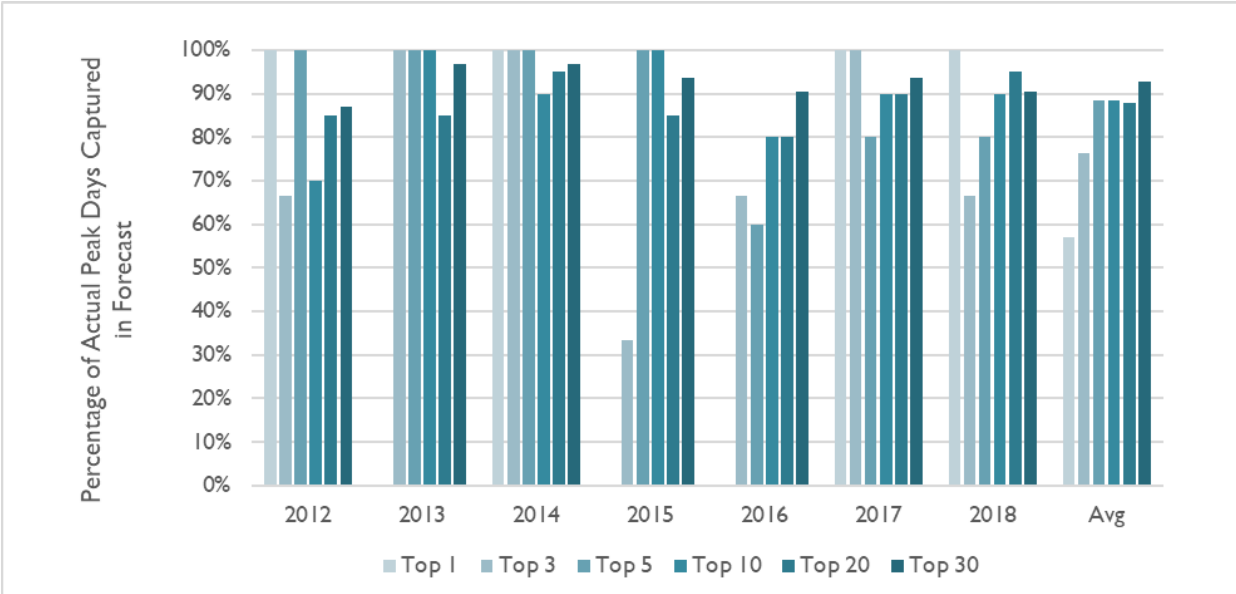
[398] Results are similar, but the curves are less smooth.

[399] The ISO New England day-ahead forecasts are actually quite accurate, correctly flagging the highest *d* days of the summer, if the load of the lowest of those days is known.

Where the day-ahead load would result in activation of a day outside the targeted group, it is almost always close to the intended group. For example, a program targeted at the top 10 days might miss day six, but that unused activation would likely be present on day 11 or 12.

Figure 71. Percentage of highest days flagged by day-ahead load forecast, by year



Dispatching demand response, missing some days

Figure 71 shows the targeting errors if the program administrator somehow knew what the load would be on day d, the lowest load day for which the administrator should activate the program. A more realistic simulation recognizes that the program administrator does not know in early July whether the rest of the summer will be hot or mild, and thus will not know whether a particular day-ahead load forecast is likely to be one the *d* highest days.

Table 179 shows how close the load reductions would be to the perfect-information case with typical substitution of peak days with days just outside the targeted period. For example, Sensitivity Case 4 tests the effect on load reductions of calling an event on the 14th highest day rather than the 9th day of a 10-day per year program, while Sensitivity Case 5 models the effect of calling an event on the 14th highest day rather than the 6th day. Other than Sensitivity Case 1 (an unlikely single-day program calling an event on the second-highest day, rather than the highest-load day), the effect of the imperfect dispatch is within 6 percent of the effect of perfect dispatch, and sometimes the dispatch error actually increases the reduction in forecast load.

Table 179. Ratios of forecast reduction with minor dispatch errors, as a percentage of forecast reduction from perfect dispatch

Sensitivity Case	Event Days	Changes from Optimal Dispatch		Years of Operation			
		Top Days Missed	*Non-Top Days added*	*1*	*5*	*10*	*15*
1	1	#1	#2	67%	92%	92%	81%
2	3	#3	#4	99%	105%	99%	98%
3	5	#5	#7	101%	101%	98%	98%
4	10	#9	#14	99%	97%	98%	98%
5	10	#6	#14	99%	96%	98%	97%
6	20	#14, #17	#25, #30	100%	99%	98%	96%
7	20	#11, #12	#22, #23	98%	97%	97%	96%
8	20	#16, #20	#27, #32	103%	100%	98%	97%
9	31	#18, #24, #27, #30	#34, #37, #40, #43	96%	96%	96%	94%
10	31	#18, #27, #31	#34, #37, #40	98%	97%	97%	95%

Table 180 shows the results for poorly targeted dispatch of a load reduction program in the top 30 days of the summer, either 10 events per year on every third day (starting with day 1 or day 2) or 15 events per year on every second day (either the even-numbered days or the odd-numbered). These dispatch choices represent nearly the worst cases for 10 or 15 annual events, yet they still produce 62 percent to 92 percent of the forecast reduction due to load reductions perfectly targeted to the 10 or 15 days with highest loads.

Table 180. Ratios of forecast reduction with even more imperfect dispatch, as a percentage of forecasted reduction from perfect dispatch

Event Days	Dispatch Days, Ranked by Load	Years of Operation			
		1	*5*	*10*	*15*
10	Every 3rd day: 1, 4, 7, 10, 13, 16, 19, 22, 25, 28	85%	78%	75%	68%
10	Every 3rd day: 2, 5, 8, 11, 14, 17, 20, 23, 26, 29	73%	72%	71%	62%
15	Odd days: 1,3, 5, 7, 9, 11,13,15,17,19,21, 23,25, 27, 29	92%	84%	82%	76%
15	Even days: 2, 4, 6, 8, 10,12,14, 16, 18, 20, 22, 24, 26, 28, 30	84%	78%	76%	68%

Dispatching demand response with forecast load distribution

To examine dispatch errors more systematically, we tested a case in which the program was activated and load was curtailed when the day-ahead forecast was within *k*% of ISO New England's forecast of the summer peak, where *k* is the percentage of peak that, on average over the historical data, was exceeded for *d* days per year.

This is a simplified example of a typical demand response program (such as dynamic peak pricing), in which the program administrator tries to foresee peak days and curtail load on those days. In some low-load years, the program will miss some days that later turn out to have been in the top *d* days, while in other years, the program will operate on days that turn out not to be in the top *d* days.

Demand response program administrators are likely to be more sophisticated than the simple algorithm that we used. For example, the program administrator will know how much of the summer remains, how many event days are left for the year, whether the remainder of the summer is forecast to be warmer or cooler than usual, and what a more detailed forecast for the next week or more shows.

Assuming that the program administrator has no information about the loads for the particular year, dispatching with this simple algorithm results in forecast load savings of 80 percent to 100 percent of the perfect-information dispatch, from about four to fifty event days annually. The detailed pattern of differences between the values shown in Subappendix A and Subappedix B may well be due to the different performance of the algorithm in the specific historical years. Overall, a reasonably thoughtful program administrator should be able to achieve about 95 percent of the benefits shown in Subappendix A.

Daily dispatch values

Finally, we estimated the effects of load reductions in just a single day each year, from the highest-load day to the lowest-load day of the summer, and for one to fifteen years of program operation. The specific effect of reductions in any particular day is probably very sensitive to the specific historical pattern of daily loads and weather, so the detailed differences in the daily values (for example, between the 18th and 19th days, or between seven years and eight years) may not be significant. See Appendix C for our estimate of the R value (reduction in the 2021 forecast as a fraction of the annual historical load reductions), for various number of years and various numbers of days per year.

These daily values, if summed up for the top *d* days, produce load reductions lower than those we found for reductions in the top *d* days. This is illustrated in Figure 72, Figure 73, and Figure 74, for programs lasting 1, 5, and 15 years, respectively. In each figure, we plot the sum of the daily contributions to reducing the load forecast (the sum of days) as compared to the reduction from the top days as a group (the optimal dispatch results). The latter is always larger.

Figure 72. Reduction ratio (R) for 1-year program, various numbers of days

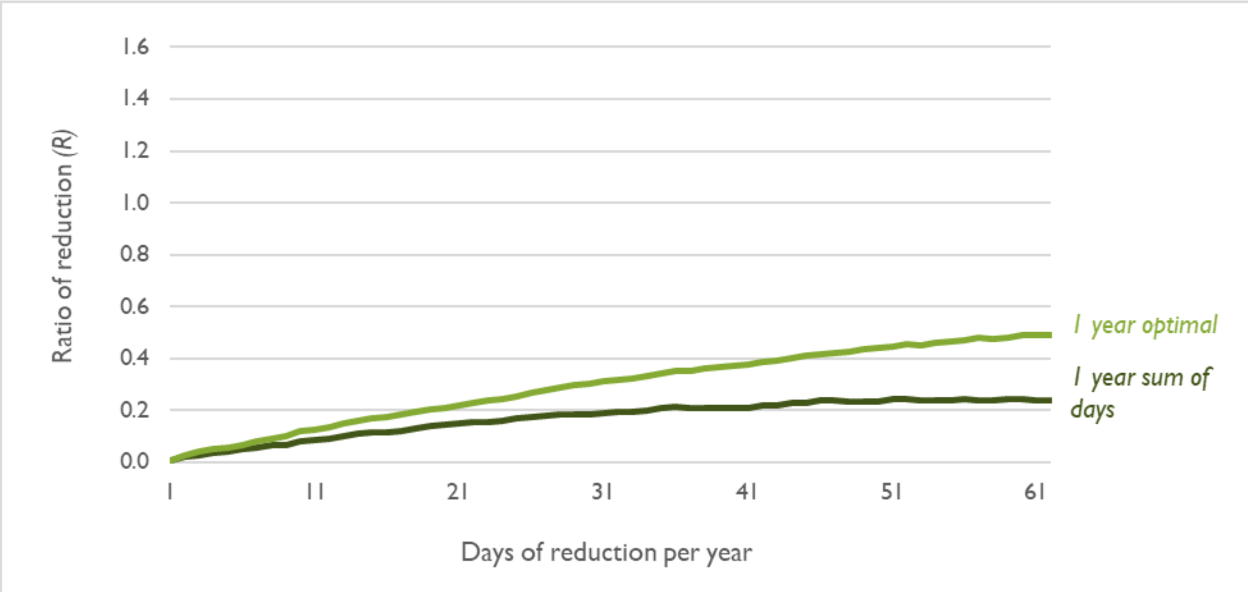


Figure 73. Reduction ratio (R) for 5-year program, various numbers of days

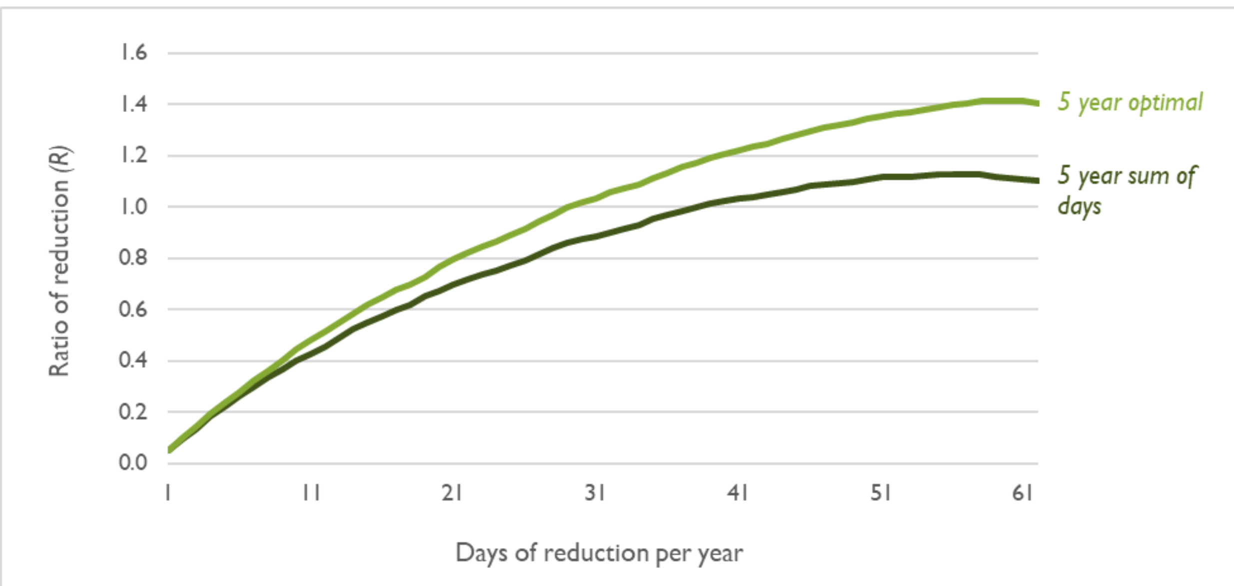
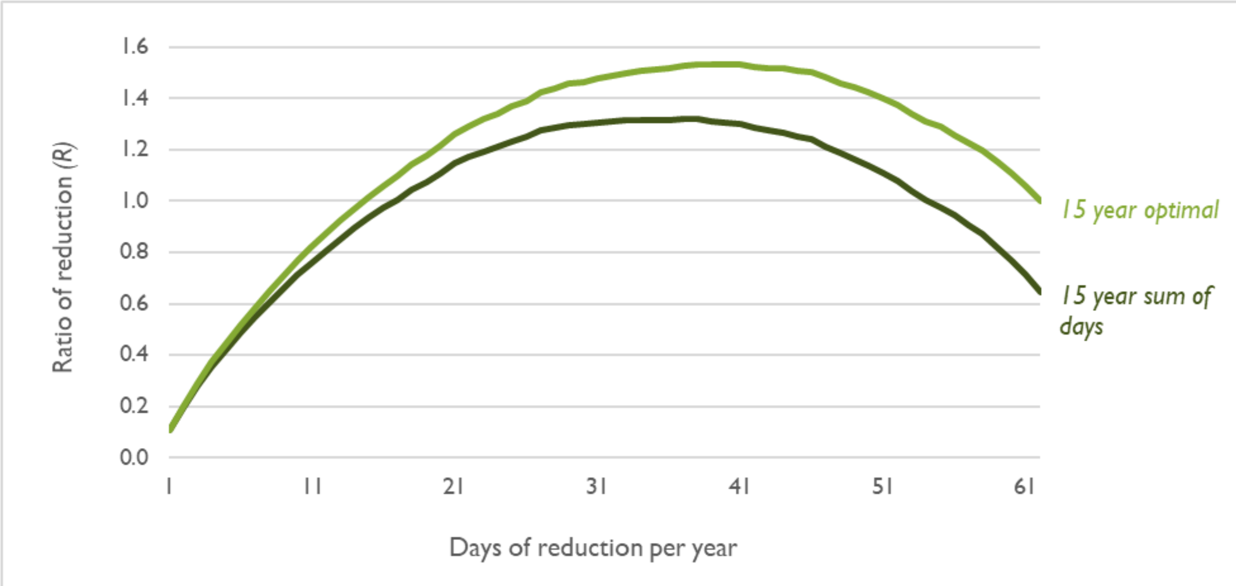


Figure 74. Reduction ratio (R) for 15-year program, various numbers of days



The question then arises, without computing the effects of reductions on all the possible combinations of days (on the order of 10^{18} possibilities), how can the effect of some set of load reductions on uncleared capacity and capacity DRIPE be estimated?

We propose that the load effect (R) for reductions on a set of days *S*, for which the lowest-load day in *S* is the D^{th} highest load day of the summer, be estimated as the average of

1. The sum of the R values for the days in S (from Table 183, Subappendix C), and
2. The R value for D days (from Table 181, Subappendix A), minus the sum of the R values for the days less than D that are not in S (from Table 183, Subappendix C).

For days 1, 4, and 5 of a one-year program (or a program that has only been running for a year), the value would be the average of

The sum of 0.009, 0.013 and 0.005, or 0.027, and

0.06 minus (0.010 + 0.006), or 0.044.

(0.027 + 0.044) ÷ 2 = 0.036.

If greater precision is necessary, or for more complex situations, for example to estimate the effect of different amounts of load reduction on different days over multiple years, we recommend repeating the regressions we describe above for the specific situation.

Subappendix A. Ratio of forecast reduction to load reduction

Table 181 displays the values behind Figure 69 and Figure 70. These values can be applied to uncleared capacity and capacity DRIPE values from AESC 2021 to determine new capacity DRIPE values that are specific to a demand response program.

Table 181. Ratio of forecast reduction to load reduction, by years and days per year

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	0.01	0.02	0.03	0.05	0.05	0.06	0.07	0.08	0.08	0.09	0.10	0.10	0.10	0.11	0.11
2	0.03	0.05	0.06	0.09	0.10	0.13	0.14	0.15	0.16	0.17	0.18	0.19	0.20	0.20	0.20
3	0.04	0.07	0.10	0.13	0.15	0.17	0.20	0.22	0.23	0.25	0.26	0.28	0.28	0.29	0.29
4	0.05	0.09	0.13	0.17	0.19	0.23	0.26	0.29	0.30	0.32	0.34	0.36	0.36	0.37	0.37
5	0.06	0.11	0.16	0.22	0.24	0.28	0.32	0.35	0.37	0.39	0.41	0.44	0.44	0.44	0.45
6	0.07	0.13	0.19	0.25	0.28	0.32	0.37	0.41	0.43	0.45	0.48	0.50	0.50	0.50	0.52
7	0.08	0.15	0.22	0.29	0.33	0.38	0.43	0.47	0.49	0.51	0.54	0.57	0.57	0.57	0.58
8	0.09	0.17	0.25	0.33	0.36	0.42	0.48	0.53	0.55	0.57	0.61	0.64	0.64	0.63	0.65
9	0.10	0.19	0.27	0.37	0.40	0.47	0.53	0.58	0.61	0.63	0.67	0.70	0.70	0.69	0.71
10	0.12	0.21	0.30	0.41	0.45	0.52	0.58	0.63	0.66	0.69	0.72	0.76	0.75	0.75	0.77
11	0.13	0.23	0.33	0.45	0.48	0.55	0.63	0.68	0.71	0.74	0.78	0.82	0.81	0.80	0.82
12	0.14	0.25	0.35	0.48	0.52	0.59	0.67	0.73	0.76	0.79	0.83	0.87	0.86	0.86	0.88
13	0.15	0.27	0.38	0.52	0.55	0.64	0.72	0.78	0.81	0.85	0.88	0.93	0.92	0.91	0.93
14	0.16	0.29	0.40	0.54	0.58	0.68	0.76	0.83	0.86	0.89	0.93	0.97	0.96	0.95	0.97
15	0.17	0.31	0.43	0.58	0.62	0.71	0.80	0.87	0.90	0.94	0.98	1.03	1.01	1.00	1.02
16	0.18	0.33	0.45	0.60	0.65	0.75	0.84	0.91	0.95	0.98	1.02	1.07	1.06	1.04	1.06
17	0.19	0.34	0.47	0.63	0.68	0.78	0.88	0.95	0.99	1.02	1.07	1.12	1.10	1.08	1.10
18	0.20	0.36	0.50	0.66	0.70	0.81	0.91	0.99	1.03	1.07	1.11	1.17	1.15	1.13	1.14
19	0.20	0.38	0.52	0.69	0.73	0.84	0.95	1.04	1.07	1.11	1.15	1.21	1.19	1.17	1.18
20	0.21	0.39	0.54	0.71	0.77	0.88	0.99	1.07	1.11	1.15	1.20	1.26	1.23	1.21	1.22
21	0.22	0.41	0.56	0.74	0.80	0.92	1.03	1.12	1.16	1.20	1.24	1.30	1.27	1.25	1.26
22	0.23	0.42	0.58	0.77	0.82	0.94	1.06	1.15	1.19	1.23	1.27	1.33	1.30	1.28	1.29
23	0.24	0.44	0.60	0.79	0.85	0.96	1.09	1.19	1.23	1.27	1.31	1.37	1.34	1.31	1.32
24	0.25	0.45	0.62	0.82	0.87	0.98	1.12	1.21	1.26	1.29	1.34	1.40	1.36	1.33	1.34
25	0.25	0.47	0.64	0.84	0.89	1.01	1.15	1.25	1.29	1.33	1.37	1.43	1.40	1.36	1.37
26	0.27	0.49	0.66	0.86	0.91	1.04	1.18	1.28	1.32	1.36	1.40	1.47	1.42	1.39	1.39
27	0.28	0.50	0.68	0.89	0.95	1.07	1.22	1.32	1.36	1.40	1.44	1.50	1.46	1.42	1.42
28	0.29	0.52	0.71	0.92	0.97	1.11	1.25	1.35	1.39	1.43	1.47	1.53	1.48	1.44	1.44
29	0.30	0.54	0.73	0.94	1.00	1.14	1.28	1.38	1.42	1.46	1.49	1.56	1.51	1.46	1.46
30	0.30	0.55	0.74	0.96	1.02	1.15	1.31	1.41	1.45	1.49	1.52	1.58	1.53	1.48	1.47
31	0.31	0.56	0.76	0.98	1.04	1.18	1.33	1.44	1.48	1.51	1.54	1.61	1.55	1.49	1.48
32	0.32	0.58	0.78	1.00	1.06	1.21	1.36	1.47	1.50	1.54	1.57	1.63	1.57	1.51	1.49
33	0.32	0.59	0.79	1.02	1.07	1.22	1.38	1.49	1.53	1.56	1.59	1.66	1.59	1.52	1.50
34	0.33	0.60	0.80	1.04	1.09	1.25	1.41	1.52	1.55	1.59	1.61	1.68	1.60	1.53	1.51
35	0.34	0.61	0.82	1.06	1.11	1.27	1.43	1.54	1.58	1.61	1.63	1.70	1.62	1.54	1.51
36	0.35	0.62	0.84	1.08	1.13	1.29	1.46	1.57	1.60	1.63	1.65	1.71	1.63	1.55	1.52
37	0.35	0.64	0.85	1.10	1.16	1.31	1.49	1.59	1.62	1.65	1.67	1.73	1.65	1.57	1.53
38	0.36	0.65	0.86	1.12	1.17	1.34	1.51	1.61	1.64	1.67	1.69	1.75	1.66	1.58	1.53
39	0.37	0.66	0.88	1.14	1.19	1.35	1.53	1.63	1.66	1.69	1.71	1.77	1.67	1.58	1.53
40	0.37	0.67	0.89	1.15	1.21	1.36	1.55	1.65	1.68	1.71	1.72	1.78	1.68	1.59	1.53
41	0.38	0.68	0.90	1.17	1.22	1.39	1.57	1.67	1.69	1.72	1.73	1.79	1.68	1.59	1.53
42	0.39	0.69	0.92	1.19	1.23	1.41	1.59	1.69	1.71	1.73	1.74	1.80	1.69	1.59	1.52

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
43	0.39	0.70	0.93	1.20	1.25	1.42	1.61	1.70	1.72	1.75	1.76	1.81	1.69	1.59	1.52
44	0.40	0.71	0.95	1.21	1.26	1.44	1.63	1.72	1.74	1.76	1.77	1.82	1.70	1.60	1.52
45	0.41	0.73	0.96	1.23	1.28	1.46	1.64	1.74	1.75	1.77	1.78	1.83	1.70	1.60	1.51
46	0.42	0.74	0.97	1.25	1.30	1.48	1.66	1.76	1.77	1.79	1.79	1.84	1.71	1.60	1.50
47	0.42	0.75	0.99	1.27	1.31	1.49	1.68	1.77	1.78	1.80	1.79	1.84	1.70	1.58	1.48
48	0.42	0.76	1.00	1.27	1.32	1.50	1.70	1.78	1.79	1.80	1.79	1.84	1.69	1.57	1.46
49	0.43	0.77	1.01	1.29	1.33	1.52	1.71	1.79	1.80	1.80	1.79	1.84	1.68	1.55	1.44
50	0.44	0.78	1.03	1.31	1.34	1.53	1.73	1.81	1.81	1.81	1.80	1.84	1.68	1.54	1.42
51	0.45	0.79	1.04	1.32	1.35	1.55	1.73	1.82	1.82	1.81	1.80	1.83	1.66	1.53	1.40
52	0.45	0.80	1.05	1.33	1.36	1.55	1.74	1.82	1.82	1.81	1.79	1.82	1.65	1.51	1.37
53	0.45	0.80	1.06	1.34	1.37	1.56	1.74	1.82	1.81	1.80	1.78	1.81	1.63	1.48	1.34
54	0.46	0.82	1.07	1.35	1.38	1.57	1.75	1.82	1.82	1.80	1.77	1.80	1.61	1.46	1.31
55	0.46	0.82	1.08	1.36	1.39	1.57	1.75	1.83	1.82	1.80	1.77	1.79	1.60	1.45	1.29
56	0.47	0.83	1.09	1.37	1.40	1.58	1.76	1.83	1.82	1.79	1.75	1.78	1.58	1.42	1.26
57	0.48	0.84	1.10	1.38	1.40	1.59	1.77	1.83	1.82	1.79	1.75	1.76	1.56	1.40	1.23
58	0.48	0.85	1.11	1.39	1.41	1.60	1.77	1.83	1.82	1.78	1.73	1.75	1.55	1.37	1.20
59	0.48	0.86	1.11	1.40	1.41	1.60	1.77	1.83	1.81	1.77	1.71	1.72	1.51	1.33	1.15
60	0.49	0.86	1.12	1.40	1.41	1.60	1.77	1.83	1.81	1.76	1.69	1.70	1.48	1.30	1.11
61	0.49	0.86	1.12	1.41	1.41	1.60	1.77	1.83	1.80	1.75	1.68	1.68	1.45	1.26	1.06
62	0.49	0.86	1.12	1.40	1.40	1.59	1.76	1.81	1.79	1.73	1.65	1.65	1.42	1.21	1.00

Subappendix B. Ratio of forecast reduction to load reduction, with forecast load distribution

Table 182 displays a modified version of the values in Subappendix A, assuming imperfect dispatch. See the main body of Appendix K, subsection "Dispatching demand response with forecast load distribution" for more information.

Table 182. Ratio of forecast reduction to load reduction, imperfect dispatch

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
1	0.01	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05
2	0.02	0.02	0.02	0.05	0.06	0.07	0.09	0.09	0.09	0.10	0.10	0.11	0.11	0.11	0.12
3	0.03	0.06	0.08	0.11	0.13	0.15	0.17	0.17	0.17	0.19	0.20	0.21	0.21	0.21	0.21
4	0.04	0.09	0.13	0.17	0.19	0.21	0.25	0.26	0.26	0.27	0.28	0.30	0.30	0.30	0.30
5	0.05	0.11	0.15	0.20	0.22	0.25	0.29	0.30	0.31	0.33	0.34	0.36	0.36	0.36	0.36
6	0.06	0.13	0.17	0.23	0.25	0.29	0.34	0.36	0.37	0.39	0.40	0.42	0.42	0.42	0.42
7	0.07	0.14	0.20	0.27	0.29	0.33	0.38	0.40	0.41	0.44	0.45	0.47	0.47	0.46	0.46
8	0.08	0.16	0.23	0.30	0.32	0.37	0.42	0.45	0.46	0.48	0.50	0.52	0.52	0.51	0.51
9	0.09	0.18	0.25	0.32	0.35	0.40	0.46	0.49	0.50	0.52	0.54	0.57	0.56	0.55	0.55
10	0.10	0.20	0.27	0.35	0.39	0.44	0.51	0.54	0.55	0.58	0.60	0.62	0.62	0.61	0.60
11	0.12	0.22	0.29	0.38	0.42	0.49	0.56	0.59	0.60	0.63	0.65	0.68	0.68	0.66	0.66
12	0.12	0.23	0.31	0.41	0.45	0.53	0.60	0.64	0.65	0.68	0.70	0.73	0.73	0.71	0.71
13	0.13	0.24	0.32	0.44	0.47	0.55	0.64	0.67	0.69	0.71	0.74	0.77	0.77	0.75	0.75
14	0.14	0.25	0.34	0.47	0.51	0.60	0.68	0.71	0.73	0.76	0.79	0.82	0.82	0.80	0.80
15	0.15	0.29	0.38	0.52	0.57	0.66	0.75	0.79	0.82	0.85	0.88	0.91	0.91	0.88	0.88
16	0.15	0.30	0.40	0.55	0.59	0.69	0.78	0.83	0.85	0.88	0.92	0.96	0.94	0.92	0.91
17	0.17	0.32	0.43	0.58	0.62	0.73	0.82	0.88	0.90	0.94	0.98	1.02	1.00	0.98	0.97
18	0.17	0.34	0.45	0.60	0.64	0.75	0.85	0.92	0.94	0.98	1.02	1.06	1.04	1.00	0.99
19	0.18	0.35	0.46	0.62	0.67	0.78	0.88	0.95	0.98	1.01	1.05	1.09	1.07	1.03	1.02
20	0.19	0.37	0.48	0.64	0.69	0.80	0.91	0.98	1.01	1.05	1.09	1.14	1.11	1.06	1.06
21	0.19	0.38	0.49	0.66	0.71	0.82	0.93	1.00	1.03	1.07	1.10	1.15	1.13	1.08	1.07
22	0.20	0.39	0.50	0.68	0.73	0.84	0.96	1.03	1.06	1.10	1.13	1.19	1.16	1.10	1.09
23	0.21	0.41	0.54	0.71	0.76	0.88	1.00	1.07	1.11	1.14	1.18	1.24	1.20	1.14	1.13
24	0.22	0.43	0.56	0.74	0.78	0.90	1.02	1.10	1.13	1.17	1.21	1.26	1.23	1.16	1.15
25	0.23	0.44	0.58	0.76	0.81	0.93	1.06	1.14	1.18	1.21	1.25	1.31	1.27	1.21	1.19
26	0.23	0.45	0.58	0.78	0.82	0.95	1.08	1.16	1.20	1.23	1.27	1.33	1.30	1.23	1.22
27	0.24	0.47	0.60	0.80	0.84	0.97	1.10	1.18	1.22	1.26	1.30	1.36	1.33	1.26	1.25
28	0.25	0.48	0.61	0.81	0.86	0.99	1.13	1.21	1.25	1.29	1.32	1.38	1.34	1.27	1.26
29	0.26	0.50	0.63	0.84	0.88	1.02	1.16	1.25	1.29	1.32	1.36	1.42	1.38	1.31	1.29
30	0.26	0.50	0.63	0.85	0.89	1.03	1.17	1.26	1.30	1.34	1.37	1.43	1.39	1.31	1.29
31	0.27	0.52	0.66	0.87	0.92	1.06	1.21	1.29	1.34	1.37	1.40	1.46	1.42	1.33	1.32
32	0.28	0.53	0.68	0.90	0.94	1.08	1.24	1.32	1.36	1.40	1.43	1.49	1.44	1.35	1.33
33	0.29	0.55	0.71	0.93	0.98	1.12	1.28	1.37	1.41	1.44	1.47	1.53	1.48	1.39	1.35
34	0.30	0.56	0.72	0.95	1.00	1.15	1.31	1.39	1.44	1.47	1.49	1.56	1.50	1.41	1.37
35	0.31	0.58	0.74	0.98	1.03	1.18	1.34	1.43	1.47	1.50	1.53	1.58	1.53	1.44	1.40
36	0.33	0.60	0.78	1.01	1.06	1.21	1.37	1.47	1.51	1.54	1.56	1.62	1.56	1.46	1.43
37	0.34	0.62	0.80	1.04	1.09	1.24	1.41	1.50	1.54	1.57	1.59	1.65	1.58	1.48	1.44
38	0.35	0.63	0.82	1.06	1.11	1.27	1.44	1.53	1.57	1.60	1.62	1.68	1.59	1.50	1.44
39	0.35	0.64	0.83	1.09	1.13	1.29	1.46	1.55	1.60	1.63	1.64	1.69	1.60	1.50	1.45
40	0.36	0.66	0.85	1.10	1.15	1.31	1.48	1.58	1.62	1.65	1.66	1.71	1.62	1.52	1.46
41	0.37	0.67	0.87	1.12	1.17	1.33	1.51	1.61	1.64	1.67	1.68	1.73	1.61	1.50	1.43
42	0.37	0.67	0.88	1.13	1.17	1.34	1.52	1.61	1.65	1.67	1.69	1.73	1.60	1.48	1.41
43	0.38	0.68	0.89	1.15	1.19	1.35	1.53	1.63	1.67	1.69	1.70	1.75	1.61	1.50	1.42
44	0.39	0.69	0.90	1.15	1.20	1.37	1.55	1.64	1.68	1.70	1.71	1.75	1.62	1.50	1.41

	Years of Reductions														
Days	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**
45	0.39	0.70	0.92	1.18	1.21	1.39	1.57	1.67	1.70	1.73	1.73	1.77	1.64	1.52	1.42
46	0.40	0.71	0.93	1.19	1.23	1.40	1.59	1.70	1.73	1.75	1.75	1.79	1.66	1.54	1.44
47	0.40	0.72	0.94	1.20	1.24	1.41	1.60	1.71	1.74	1.76	1.76	1.79	1.65	1.53	1.43
48	0.41	0.73	0.95	1.21	1.24	1.41	1.60	1.71	1.73	1.76	1.75	1.78	1.63	1.50	1.40
49	0.41	0.74	0.96	1.22	1.26	1.43	1.62	1.73	1.75	1.78	1.77	1.80	1.65	1.51	1.40
50	0.42	0.75	0.97	1.23	1.27	1.44	1.64	1.74	1.76	1.79	1.78	1.80	1.64	1.50	1.38
51	0.42	0.76	0.98	1.25	1.28	1.46	1.65	1.76	1.78	1.81	1.79	1.82	1.65	1.51	1.38
52	0.43	0.78	1.01	1.28	1.31	1.49	1.68	1.79	1.81	1.82	1.80	1.82	1.66	1.51	1.38
53	0.45	0.79	1.02	1.30	1.33	1.51	1.70	1.81	1.83	1.85	1.82	1.84	1.67	1.52	1.38
54	0.45	0.80	1.03	1.31	1.34	1.52	1.71	1.82	1.84	1.85	1.83	1.84	1.68	1.52	1.37
55	0.46	0.81	1.05	1.32	1.34	1.52	1.71	1.82	1.83	1.84	1.80	1.82	1.64	1.47	1.32
56	0.46	0.82	1.06	1.33	1.35	1.53	1.73	1.83	1.84	1.84	1.80	1.81	1.63	1.46	1.30
57	0.47	0.83	1.07	1.34	1.36	1.54	1.73	1.83	1.84	1.84	1.79	1.80	1.62	1.44	1.27
58	0.47	0.84	1.08	1.35	1.37	1.56	1.75	1.84	1.85	1.85	1.80	1.81	1.62	1.44	1.26
59	0.47	0.83	1.08	1.35	1.36	1.54	1.73	1.81	1.80	1.76	1.72	1.72	1.53	1.34	1.16
60	0.48	0.85	1.09	1.37	1.37	1.56	1.73	1.81	1.80	1.77	1.72	1.72	1.52	1.34	1.14
61	0.48	0.85	1.10	1.38	1.39	1.57	1.73	1.81	1.79	1.76	1.71	1.71	1.48	1.28	1.08
62	0.49	0.86	1.12	1.39	1.39	1.58	1.75	1.82	1.80	1.76	1.69	1.69	1.45	1.26	1.04

Subappendix C. Impact of individual day load reductions

Table 183 shows our estimate of the R value (reduction in the 2021 forecast as a fraction of the annual historical load reductions), for various number of years and various numbers of days per year. See the main body of Appendix K, subsection "Daily dispatch values" for more information.

Table 183. Effect of individual day load reductions on reduction ratios

Days	Years of Reductions														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	0.009	0.021	0.032	0.046	0.051	0.063	0.072	0.079	0.082	0.089	0.096	0.102	0.104	0.106	0.108
2	0.010	0.021	0.031	0.040	0.046	0.056	0.064	0.073	0.078	0.081	0.081	0.086	0.086	0.086	0.087
3	0.006	0.016	0.025	0.036	0.040	0.047	0.056	0.062	0.065	0.069	0.074	0.080	0.080	0.080	0.083
4	0.013	0.024	0.035	0.046	0.050	0.056	0.063	0.069	0.070	0.067	0.081	0.083	0.075	0.075	0.077
5	0.005	0.016	0.026	0.036	0.038	0.044	0.050	0.055	0.058	0.060	0.064	0.067	0.066	0.066	0.068
6	0.011	0.014	0.020	0.038	0.041	0.046	0.052	0.050	0.052	0.053	0.057	0.061	0.059	0.058	0.060
7	0.005	0.013	0.022	0.033	0.034	0.040	0.047	0.052	0.054	0.054	0.056	0.060	0.059	0.058	0.059
8	0.007	0.022	0.024	0.035	0.036	0.045	0.052	0.055	0.056	0.059	0.060	0.062	0.062	0.061	0.063
9	0.004	0.013	0.021	0.031	0.034	0.039	0.044	0.049	0.053	0.054	0.055	0.057	0.055	0.054	0.053
10	0.012	0.014	0.021	0.032	0.030	0.038	0.043	0.047	0.048	0.050	0.050	0.052	0.051	0.051	0.053
11	0.006	0.014	0.020	0.027	0.027	0.032	0.038	0.042	0.043	0.046	0.048	0.050	0.048	0.047	0.047
12	0.004	0.013	0.020	0.027	0.029	0.035	0.040	0.045	0.047	0.049	0.050	0.051	0.050	0.048	0.049
13	0.013	0.022	0.027	0.033	0.036	0.041	0.045	0.049	0.049	0.052	0.045	0.048	0.047	0.046	0.045
14	0.009	0.010	0.017	0.023	0.031	0.028	0.033	0.037	0.038	0.038	0.039	0.042	0.039	0.037	0.043
15	0.004	0.013	0.018	0.024	0.027	0.032	0.036	0.039	0.040	0.041	0.044	0.046	0.044	0.042	0.041
16	0.002	0.010	0.016	0.022	0.023	0.029	0.033	0.036	0.037	0.039	0.039	0.041	0.039	0.036	0.036
17	0.004	0.011	0.016	0.021	0.023	0.027	0.031	0.033	0.035	0.036	0.038	0.041	0.038	0.034	0.033
18	0.009	0.012	0.023	0.024	0.023	0.027	0.031	0.036	0.036	0.037	0.037	0.039	0.040	0.038	0.037
19	0.010	0.017	0.023	0.023	0.031	0.026	0.032	0.036	0.037	0.037	0.036	0.038	0.033	0.031	0.030
20	0.006	0.012	0.012	0.018	0.020	0.023	0.029	0.031	0.034	0.036	0.037	0.039	0.037	0.034	0.035
21	0.004	0.011	0.017	0.023	0.025	0.029	0.033	0.036	0.038	0.037	0.037	0.039	0.039	0.035	0.037
22	0.004	0.010	0.014	0.021	0.019	0.022	0.025	0.028	0.027	0.028	0.026	0.027	0.024	0.024	0.026
23	0.001	0.009	0.015	0.020	0.021	0.024	0.027	0.030	0.030	0.029	0.028	0.032	0.028	0.024	0.022
24	0.007	0.012	0.010	0.015	0.014	0.016	0.019	0.022	0.022	0.022	0.028	0.023	0.019	0.016	0.019
25	0.008	0.015	0.018	0.021	0.023	0.024	0.028	0.030	0.027	0.028	0.026	0.027	0.024	0.023	0.021
26	0.006	0.013	0.018	0.016	0.018	0.021	0.026	0.028	0.027	0.026	0.026	0.027	0.023	0.019	0.018
27	0.005	0.012	0.017	0.024	0.025	0.027	0.030	0.032	0.031	0.031	0.031	0.031	0.028	0.027	0.025
28	0.003	0.009	0.021	0.021	0.025	0.024	0.026	0.032	0.025	0.024	0.021	0.021	0.017	0.013	0.009
29	0.001	0.008	0.013	0.017	0.017	0.023	0.026	0.026	0.025	0.025	0.023	0.023	0.022	0.016	0.012
30	0.002	0.009	0.012	0.015	0.015	0.017	0.021	0.021	0.020	0.020	0.018	0.017	0.013	0.008	0.003

Days	Years of Reductions														
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
31	0.002	0.013	0.016	0.014	0.013	0.016	0.019	0.021	0.020	0.020	0.019	0.019	0.014	0.009	0.005
32	0.008	0.007	0.010	0.015	0.015	0.016	0.020	0.021	0.021	0.020	0.017	0.018	0.014	0.010	0.005
33	0.000	0.005	0.007	0.011	0.012	0.015	0.018	0.020	0.020	0.019	0.018	0.018	0.012	0.009	0.005
34	0.006	0.005	0.013	0.018	0.018	0.021	0.024	0.025	0.024	0.023	0.013	0.013	0.008	0.005	-0.001
35	0.009	0.015	0.018	0.022	0.021	0.017	0.019	0.018	0.016	0.016	0.013	0.013	0.008	0.005	0.000
36	0.002	0.006	0.010	0.015	0.015	0.016	0.019	0.018	0.016	0.015	0.013	0.012	0.008	0.004	0.002
37	-0.001	0.006	0.009	0.014	0.015	0.018	0.020	0.018	0.016	0.015	0.014	0.014	0.009	0.007	0.002
38	-0.001	0.005	0.007	0.018	0.018	0.015	0.016	0.016	0.016	0.015	0.013	0.012	0.009	0.005	-0.001
39	0.000	0.005	0.008	0.011	0.010	0.012	0.014	0.012	0.012	0.011	0.010	0.008	0.002	0.000	-0.006
40	-0.001	0.005	0.009	0.012	0.010	0.010	0.013	0.013	0.012	0.010	0.008	0.008	0.002	-0.002	-0.008
41	0.001	0.006	0.009	0.011	0.011	0.014	0.015	0.014	0.012	0.012	0.010	0.008	0.002	-0.002	-0.006
42	0.008	0.005	0.008	0.010	0.008	0.010	0.012	0.010	0.008	0.005	0.003	0.002	-0.004	-0.008	-0.015
43	0.001	0.005	0.006	0.007	0.008	0.012	0.013	0.013	0.010	0.008	0.006	0.004	0.000	-0.003	-0.010
44	0.008	0.013	0.007	0.016	0.011	0.013	0.015	0.012	0.011	0.010	0.007	0.006	0.003	-0.001	-0.008
45	0.001	0.005	0.007	0.009	0.009	0.011	0.012	0.009	0.006	0.003	0.003	-0.001	-0.007	-0.009	-0.016
46	0.007	0.005	0.008	0.011	0.012	0.012	0.015	0.014	0.011	0.009	0.008	0.005	-0.001	-0.006	-0.011
47	0.001	0.005	0.009	0.010	0.009	0.011	0.011	0.008	0.005	0.001	-0.004	-0.007	-0.013	-0.019	-0.026
48	-0.001	0.003	0.004	0.005	0.002	0.004	0.009	0.007	0.005	0.001	-0.002	-0.004	-0.011	-0.018	-0.026
49	-0.002	0.003	0.008	0.011	0.008	0.009	0.008	0.006	0.003	-0.001	-0.005	-0.007	-0.013	-0.018	-0.023
50	0.001	0.004	0.007	0.008	0.007	0.009	0.007	0.005	0.004	-0.001	-0.004	-0.008	-0.012	-0.018	-0.026
51	0.007	0.011	0.014	0.013	0.010	0.012	0.009	0.006	0.004	-0.005	-0.008	-0.011	-0.018	-0.023	-0.031
52	-0.001	0.002	0.003	0.003	0.000	0.001	-0.001	-0.001	-0.004	-0.009	-0.011	-0.013	-0.019	-0.024	-0.029
53	-0.002	0.001	0.002	0.003	0.001	0.001	-0.001	-0.005	-0.008	-0.013	-0.018	-0.021	-0.026	-0.033	-0.041
54	0.000	0.004	0.004	0.005	0.003	0.002	0.000	-0.003	-0.007	-0.010	-0.015	-0.019	-0.024	-0.027	-0.034
55	-0.002	0.002	0.003	0.006	0.003	0.005	0.003	0.003	0.001	-0.005	-0.008	-0.010	-0.016	-0.021	-0.027
56	0.004	0.001	0.003	0.004	0.001	0.000	-0.001	-0.005	-0.007	-0.013	-0.019	-0.023	-0.021	-0.027	-0.034
57	-0.001	0.001	0.003	0.003	0.000	0.000	0.000	-0.003	-0.005	-0.010	-0.013	-0.018	-0.024	-0.030	-0.038
58	-0.002	0.001	0.002	0.003	0.000	-0.001	-0.003	-0.008	-0.010	-0.013	-0.018	-0.021	-0.025	-0.029	-0.036
59	0.004	-0.001	-0.001	-0.001	-0.006	-0.007	-0.009	-0.011	-0.014	-0.021	-0.028	-0.032	-0.039	-0.045	-0.051
60	0.002	0.004	-0.002	-0.001	-0.004	-0.003	-0.004	-0.008	-0.011	-0.017	-0.024	-0.028	-0.035	-0.042	-0.050
61	-0.005	-0.003	0.006	-0.001	-0.005	0.002	-0.007	-0.009	-0.004	-0.018	-0.025	-0.029	-0.038	-0.047	-0.055
62	0.000	-0.001	-0.002	-0.003	-0.009	-0.013	-0.014	-0.018	-0.022	-0.029	-0.037	-0.040	-0.048	-0.058	-0.068

Record Request No. 6

Request:

RR-6 – Please provide a comparison of changes between the 2018 AESC Study and the 2021 AESC study as it relates to PIM eligible net benefits.

Response:

The below table provides a comparison of changes between the 2018 AESC Study and the 2021 AESC study, as it relates to PIM eligible net benefits, where the AESC studies provide values for those benefits.

AESC Counterfactual #4	AESC 2018 (2021 cents/kWh)	AESC 2021 (2021 cents/kWh)	Comparison	AESC Source	PIM eligible net benefits
Avoided Retail Capacity Costs	2.11	1.22	-42%	Table ES-4	Capacity
Avoided Retail Energy Costs	5.32	3.90	-27%	Table ES-4	Winter Peak Energy, Winter Off Peak Energy, Summer Peak Energy, Summer Off Peak Energy
Transmission & Distribution (PTF)	2.38	2.02	-15%	Table ES-4	PTF
Value of Reliability	0.02	0.01	-32%	Table ES-4	
Electric DRIPE	3.22	1.62	-50%	Table ES-4	
Natural Gas and DRIPE ($/MMBtu)	7.91	6.48	-18%	Table ES-6	
Oil and Oil DRIPE ($/MMBtu)	23.36	24.04	2.9%	Table ES-8	Includes the avoided cost of Residential No. 2 Distillate
Propane ($/MMBtu)	32.78	38.79	18.3%	Table ES-8	

PIM eligible net benefits that are not a part of AESC include: Distribution (MDC), Utility NEIs, and Water.

Prepared by or under the supervision of: Jessica Darling and John Tortorella

Record Request No. 7

Request:

RR-7 Referencing the Company's response to DIV 2-9 in Division Set 2 (Bates 66) in the Table entitled "Sales, Technical Assistance, and Training", please indicate what component of the budget is fixed and what is variable.

Response:

Of the $1,176,483 in Sales, Technical Assistance, and Training costs shown in the Company's response to DIV 2-9, $847,000 would be fixed and $329,483 would be variable.

Although the STAT costs listed here are mostly fixed, the incentive costs associated with savings resulting from these efforts are variable.

Initiative Name	Amount	Cost Type	Explanation
HVAC/controls trade ally engagement*	$150,000	Fixed	Contract for a third-party vendor to engage trade allies
HVAC early retirements**	$200,000	Fixed	Contracted amount
Commercial real estate initiative*	$300,000 ($180,000 Fixed / $120,000 Variable)	60% Fixed / 40% Variable	Contract would likely include fixed base amount plus variable compensation depending on the volume of savings achieved through the initiative
Additional sales & engineering staff*	$317,000	Fixed	Employee compensation rates are essentially fixed, with minor variability depending performance
Additional Technical Assistance studies*	$209,483	Variable	Technical Assistance (TA) studies depend on the level of customer demand. The Company can ratchet up/down the level of spend on TA studies depending on budget constraints.

Prepared by or under the supervision of: Joshua Kessler

Record Request No. 8

Request:

RR-8 For the alternative base plan and the provisional plan, please provide the percentage of net lifetime energy savings using the following categories; measures (defined at the BCR/planning tool level) with 1 year measure life; measures with 2-5 years measure life; measures with 6-10 years measure life; and measures greater than 10 years measure life.

Response:

See table below.

	Provisional Plan		Alternative Plan		Incremental
Measure Life	**Total Net Lifetime MWh**	**% of Portfolio**	**Total Net Lifetime MWh**	**% of Portfolio**	**Total Net Lifetime MWh**
1 year	29,694	3.3%	29,694	3.6%	-
2 to 5 years	27,244	3.0%	27,039	3.2%	205
6 to 10 years	364,673	40.8%	343,798	41.2%	20,875
Greater than 10 years	471,861	52.8%	433,277	52.0%	38,584
Total	893,473		833,808		

Prepared by or under the supervision of: John Richards and Jessica Darling

Record Request No. 9

Request:

RR-9 For 2010-2022, please provide the planned PIM eligible net benefits for each year. (Please add any explanatory information the Company believes helpful in understanding the response.)

Response:

Please see the tables below for yearly planned PIM-eligible net benefits split out by sector. There are many drivers to the range of benefits shown: evaluation results influencing savings and measure life, measure mix, distribution of budgets across sectors, increasing cost to achieve savings, and changes to avoided costs including the introduction of new categories of benefits. While the magnitude of the impact of these factors are too complicated to unspool and show in this response, the AESC study associated with each year's calculation is shown in the tables.

The Company made the following assumptions in the calculation of PIM-eligible net benefits:

- For the natural gas non-income eligible and income eligible calculations, non-gas benefits were allocated entirely to the 0% (non-resource and societal) benefits category.
- For the natural gas C&I calculation, non-gas benefits were allocated entirely to the 50% resource benefits category.

Table 1: Planned PIM-Eligible Net Benefits for the Non-Income Eligible Sector

Year	Electric Net Benefits	Gas Net Benefits	AESC Used	Notes
2010	$17,180,742	$10,980,483	2009	Non-gas benefits were $0
2011	$18,340,711	$6,910,096	2009	Non-gas benefits were $0
2012	$16,798,531	$9,968,345	2011	
2013	$8,499,505	$2,763,563	2011	
2014	$30,627,918	$1,615,389	2013	
2015	$49,263,030	$16,557,350	2013	
2016	$32,319,665	$13,114,992	2015	
2017	$21,759,247	$4,496,585	2015	
2018	$3,842,992	$7,605,755	2015	
2019	$47,169,401	$614,203	2018	2019 – 2021 represents the time period where there was a significant change in measure mix, particularly the decrease in residential lighting savings.
2020	$20,390,026	-$310,016	2018	
2021	-$1,990,498	$122,149	2018	
2022*	-$1,731,867	-$4,395,277	2021	Electric net benefits from alternative base plan
2022*	-$1,738,805	-$4,395,277	2021	Electric net benefits from provisional plan

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Table 2: Planned PIM-Eligible Net Benefits for the Income Eligible Sector				
Year	**Electric Net Benefits**	**Gas Net Benefits**	**AESC Used**	**Notes**
2010	$1,191,724	$52,844	2009	
2011	$221,115	$31,480	2009	
2012	-$908,188	-$403,973	2011	
2013	-$989,695	-$247,974	2011	
2014	-$1,395,047	-$772,454	2013	
2015	$471,554	-$18,107	2013	
2016	-$4,651,657	$533,234	2015	
2017	-$1,451,697	-$586,276	2015	
2018	-$1,072,339	$1,078,201	2015	
2019	-$758,430	-$3,189,832	2018	
2020	-$6,435,887	-$3,373,620	2018	
2021	-$7,791,653	-$3,748,806	2018	
2022*	-$8,081,961	-$5,013,690	2021	Electric net benefits from alternative base plan
2022*	-$8,082,681	-$5,013,690	2021	Electric net benefits from provisional plan

Table 3: Planned PIM-Eligible Net Benefits for the C&I Sector				
Year	**Electric Net Benefits**	**Gas Net Benefits**	**AESC Used**	**Notes**
2010	$83,663,098	$10,655,383	2009	Non-gas benefits were $0
2011	$102,235,352	$6,066,634	2009	Non-gas benefits were $0
2012	$85,032,549	$9,410,741	2011	
2013	$83,477,153	$12,766,942	2011	
2014	$250,175,906	$12,028,669	2013	Includes electric benefits from very large CHP project
2015	$125,209,954	$11,446,435	2013	
2016	$79,806,732	$8,785,413	2015	
2017	$101,193,279	$16,612,847	2015	
2018	$83,183,859	$31,933,915	2015	
2019	$148,727,157	$23,577,700	2018	
2020	$120,695,878	$33,432,571	2018	
2021	$89,510,198	$9,339,492	2018	
2022*	$32,414,930	$8,826,647	2021	Electric net benefits from alternative base plan in PUC 2-17
2022*	$31,579,550	$8,826,647	2021	Electric net benefits from provisional plan

Prepared by or under the supervision of: Jessica Darling