Exhibit No. 100

Ameren – Exhibit 100
Matt Michels Testimony
Rebuttal
File No. EO-2023-0136

Exhibit No.:	
Issue(s):	Overview of IRP process, Company's Preferred Resource Plan, and Avoided costs
Witness:	Matt Michels
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MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. EO-2023-0136

REBUTTAL TESTIMONY

OF

MATT MICHELS

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
April, 2024

TABLE OF CONTENTS

REBUTTAL TESTIMONY

OF

MATT MICHELS

FILE NO. EO-2023-0136

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Matt Michels. My business address is One Ameren Plaza, 1901 Chouteau Ave., St. Louis, Missouri.

Q. By whom are you employed and what is your position?

A. I am employed by Ameren Services Company as Director of Corporate Analysis. In that capacity, I provide services to Ameren Corporation's operating subsidiaries, including Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company").

Q. Please describe your educational background and employment experience.

A. I joined Ameren Services Company in 2005 as a Consulting Engineer in Corporate Planning. My responsibilities included coordination and monitoring of projects implemented in conjunction with the integration of processes and systems following the acquisition by Ameren Corporation of Illinois Power Company ("Illinois Power") in October 2004. I was subsequently involved in the integration of combustion turbine facilities acquired by Ameren Missouri in 2006. In September 2008, I was promoted to Managing Supervisor of Resource Planning with responsibility for long-range resource planning, including Ameren Missouri's Integrated Resource Plan filings and associated analyses. In February 2013, I was promoted to Corporate Analysis Manager. In February 2014, I was promoted to Senior Manager of Corporate Analysis. In June 2017, I was promoted to Director of Corporate Analysis. My current responsibilities include long-range resource planning, energy policy analysis, environmental compliance planning analysis, fuel budgeting, and other resource related analysis.

I earned a Bachelor of Science degree in Electrical Engineering from the University of Illinois at Urbana-Champaign in May 1990. I have been employed by Ameren or Illinois Power since June of 1990 in various positions related to resource and business planning. During most of that time, my responsibilities have included the development, use, and oversight of various planning models used for purposes such as production costing, acquisition evaluation, corporate restructuring, financial forecasting, and resource planning. I have previously testified before this Commission in proceedings involving resource planning, renewable energy resources, and energy efficiency cost recovery.

II. PURPOSE OF TESTIMONY

Q. To what testimony or issues are you responding?

A. I am responding to the direct testimony of Office of Public Counsel ("OPC") witness Dr. Geoff Marke and certain Missouri Public Service Commission Staff ("Staff") witnesses regarding the Company's analysis of its 2023 Integrated Resource Plan ("IRP") filed in case number EO-2024-0020, how that IRP supports the Company's request in this case, and how the Company's avoided costs used to assess cost effectiveness of demand-side resources are determined and used. Specifically, I will respond to various criticisms of the Company's analysis and assumptions as described in the direct testimonies of Staff

Witnesses Brad Fortson, J Luebbert, and Sarah Lange as well as the alternative view of resource planning decision making set forth in the direct testimonies of these witnesses.

Q. Please summarize the key conclusions of your rebuttal testimony.

A. My rebuttal testimony will show that 1) Ameren Missouri's implementation of demand-side programs under the Missouri Energy Efficiency Investment Act ("MEEIA") has reduced the need for supply side resources and will continue to do so, 2) it is foolish to attempt to "sharpshoot" future resource needs by precisely timing the implementation of MEEIA programs based on current expectations, 3) Ameren Missouri's application of avoided capacity costs for screening demand-side resources is appropriate and not in conflict with its use of market-based capacity prices as part of its integrated analysis for its IRP comparisons, and 4) Ameren Missouri's determination of system-level avoided costs for transmission and distribution ("T&D") is appropriate and consistent with practices in other jurisdictions.

Q. Are you including any schedules with your testimony?

A. Yes, I am including the following schedule:

Schedule MM-R1 – Avoided Energy Supply Components in New England: 2024 Report.

III. IMPLEMENTATION OF DEMAND-SIDE PROGRAMS WILL CONTINUE TO REDUCE AMEREN MISSOURI'S NEED FOR SUPPLY SIDE RESOURCE ADDITIONS

Q. What do OPC and Staff witnesses contend regarding the reduction in generation needs as a result of Ameren Missouri's implementation of MEEIA programs?

A. In short, they contend that Ameren Missouri customers have realized no benefit from the Company's implementation of MEEIA programs in terms of a reduced need for generation resources and that customers will not benefit from reductions in the need for generation resources in the future if the Company continues to offer MEEIA programs to its customers. More specifically:

- Staff witness Brad Fortson contends that the Company's planned addition of generation resources in its 2023 IRP preferred resource plan ("PRP") proves that MEEIA programs have not resulted in reductions in the need for generation resources to serve customers.[1] He also contends that he does not believe the Company's IRP analysis showing the avoidance of future generation resources through the continued implementation of MEEIA programs, again citing the Company's planned generation additions in its PRP.[2]
- Staff witness J Luebbert contends, like Mr. Fortson, that the Company's planned addition of new generation resources proves that MEEIA programs do not reduce the need for generation.[3] He further contends that the Company's increase in rate base, while total fleet capacity is reduced, is proof that the Company is not avoiding other generation investments or forgoing a return on avoided investments.[4] As a result of his contention, he concludes that MEEIA provides no benefits in terms of a reduced need for new generation and that the Company should not be provided an earnings opportunity on MEEIA programs.[5]

[1] File No. EO-2023-0136, Brad J. Fortson Direct Testimony, p. 9, ll. 8-11.
[2] File No. EO-2023-0136, Brad J. Fortson Direct Testimony, p. 10, ll. 9-14.
[3] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 3, l. 23, through p. 4, l. 2.
[4] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 13, ll. 4-7.
[5] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 12, ll. 18-19.

- OPC witness Geoff Marke contends, as does Mr. Fortson and Mr. Luebbert, that Ameren Missouri's MEEIA programs are not reducing the need for generation because the Company is planning new generation additions.[6] He concludes that, as a result, Ameren Missouri and its customers have not realized any avoided cost savings in any meaningful way.[7]

Q. Has Ameren Missouri's implementation of MEEIA programs to date resulted in a reduction in the need for generation?

A. Yes. Company witness Tony Lozano discusses the savings that the Company and its customers have realized in recent years as a result of the implementation of MEEIA programs. During 2019-2022, MEEIA programs have reduced the Company's annual energy needs by nearly one million megawatt-hours ("MWh") and peak capacity needs by over 400 megawatts ("MW").[8] Company witness Steve Wills also discusses the savings already realized from MEEIA programs, indicating that the Company's annual sales are over 2.5 million MWh lower and its peak demand is over 600 MW lower than it would be absent the implementation of MEEIA programs.[9] Note that the analysis by Mr. Wills ends with calendar year 2021 and does not reflect further savings realized in 2022 and 2023.

Q. Does Ameren Missouri expect further reductions in annual sales and peak demand from continued implementation of MEEIA programs, and that these savings will reduce the need for additional generation resources?

A. Yes. As part of the Company's 2023 IRP, an alternative plan without continued implementation of MEEIA programs, Plan I, was developed and analyzed. Table 1 below

[6] File No. EO-2023-0136, Geoff Marke Direct Testimony, p. 8, ll. 13-15.
[7] File No. EO-2023-0136, Geoff Marke Direct Testimony, p. 6, l. 14.
[8] File No. EO-2023-0136, Antonio Lozano Rebuttal Testimony, p. 28, l. 15 to p. 29, l. 9.
[9] File No. EO-2023-0136, Steven Wills Rebuttal Testimony, p. 12, l. 21 to p. 13, l. 2.

shows the basic composition of Plan I and Plan C, which includes implementation of energy efficiency and demand response programs at the Realistic Achievable Potential ("RAP") level and was selected as the Company's PRP. Note that Plan I includes two additional generation resources not included in Plan C – 1,150 MW of simple cycle ("SC") gas-fired generation in 2037 and 1,200 MW of combined cycle ("CC") gas-fired generation in 2043. It also reflects the acceleration of 1,200 MW of CC generation from 2033 to 2028. These generation additions are avoided or deferred with the inclusion of continued MEEIA programs at the RAP level throughout the 20-year planning horizon.[10]

Table 1 – Resources in alternative plans with and without demand-side programs

	Plan Name	DSM EE-DR	Renewables	New Supply-Side	Coal Retirements/ Modifications
C	RAP - Renewable Expansion	RAP-RAP	Renewable Expansion	SC 2028, CC 2033 CC 2040 and 2043	Base
I	No Additional DSM	-	Renewable Expansion	SC 2028, **SC 2037** **CC 2028**, 2040, 2043 and **2043**	Base

Q. Mr. Fortson indicates that he does not believe that the additional and accelerated generation shown in Table 1 will be avoided or deferred. Does he provide any analysis to support this conclusion?

A. He provides nothing more than a surface-level analysis of the Company's prior and planned generation additions. Mr. Fortson notes that the Company is planning to add renewable and gas-fired generation as part of its transition away from a heavy reliance on coal-fired generation.[11] He also references the Company's growth in rate base, discussed further by

[10] On April 2, 2024, Ameren Missouri filed updated 2023 IRP documents to reflect a correction to Plan I. Plan I previously showed a CC addition in 2033 instead of an SC addition in 2037. The Company's risk analysis was re-run, and the correction did not affect the Company's selection of its PRP.
[11] Fortson Direct p. 10, lines 9-14.

Mr. Luebbert. He also compares the generation additions in the Company's 2023 PRP to those reflected in its 2011 IRP.[12]

Q. Do his arguments have any validity with respect to the generation deferral benefits of MEEIA?

A. None at all. To say that load reductions from implementing MEEIA programs will not reduce the Company's need for *additional* generation resources *beyond* those it already is planning is illogical. He provides no basis at all for questioning the analysis in the Company's 2023 IRP comparing Plan C (*with* demand-side resources) to Plan I (*without* demand-side resources).[13] Mr. Wills discusses Staff's position on this point in more detail in his rebuttal testimony.[14] With respect to comparison of generation additions reflected in the Company's 2023 IRP to those reflected in its 2011 IRP, the simple and obvious explanation is that these two IRPs were filed twelve years apart and reflect planning horizons with start and end dates that are also twelve years apart. At the time of the 2011 IRP, the only major generation retirements were those at the Company's Meramec Energy Center. Retirement of all three of the Company's other coal-fired energy centers – Sioux, Rush Island, and Labadie – were expected to be beyond 2030, the last year of the 20-year planning horizon for the Company's 2011 IRP. The Company's 2023 IRP now reflects the retirement of all of the Company's coal-fired resources, along with all of its gas-fired resources located in Illinois.[15] There have been other factors that have affected the Company's need for resources since the time of the

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[12] Brad J. Fortson Direct Testimony, p. 11, ll. 3-14.

[13] At the time Mr. Fortson's direct testimony was filed, the Company had not yet filed its updated 2023 IRP documents to reflect the correction to Plan I noted previously in my rebuttal testimony. However, for purposes of discussion, it is reasonable to presume that Mr. Fortson would take the same position on resource additions and deferrals that he has on the basis of the previous version of Plan I.

[14] File No. EO-2023-0136, Steven Wills Rebuttal Testimony, p. 5, l. 14, to p. 7, l. 7.

[15] Retirement of gas-fired units in Illinois is driven by the 2021 passage of that state's Climate and Equitable Jobs Act.

Company's 2011 IRP, but the retirement of an additional 4,500 MW of coal-fired capacity and 1,800 MW of gas-fired capacity (6,300 MW in total) is the single largest driver of the need for additional generation.

Q. Mr. Fortson claims that customers have not benefited from the retirements of the Company's Meramec and Rush Island Energy Centers.[16] How do you respond?

A. This is simply not true. Retirement of both Meramec and Rush Island have allowed the Company to avoid the addition of expensive pollution controls and the risks associated with future environmental regulations and federal climate policies. The Company made its case for the retirement of Meramec by the end of 2022 in its 2014 IRP[17] and in its electric rate filing made in that same year.[18] The Company retired Meramec at the end of 2022 as planned. Similarly, the Company supported its decision to retire Rush Island with analysis performed in support of its decision in late 2021, which was also presented in testimony in the Company's 2022 electric rate case,[19] and updated for testimony in the case currently before the Missouri Public Service Commission ("Commission") regarding the Company's request to securitize certain assets following the retirement of Rush Island later this year.[20] To my knowledge, Staff has not previously questioned the Company's decision to retire Meramec and has indicated in testimony before the Commission that retirement of Rush Island is appropriate and reasonable. Mr. Fortson cites statements made at hearing by Company witnesses regarding the value of energy from Rush Island.[21] Certainly it is valuable, but not so much so that it is

[16] File No. EO-2023-0136, Brad J. Fortson Direct Testimony, p. 11, l. 15-18.
[17] File No. EO-2015-0084.
[18] File No. ER-2014-0258.
[19] File No. ER-2022-0337.
[20] File No. EF-2024-0021.
[21] File No. EO-2023-0136, Brad J. Fortson Direct, p. 12, ll. 1-32.

worth the cost of adding hundreds of millions or billions in pollution controls and bear the continued risk of additional environmental and climate policy tightening.

Q. You mentioned that Mr. Luebbert discusses the Company's increases to its rate base while total capacity has fallen.[22] Does this refute in any way the notion that the Company would need even more generation resources in the absence of load reductions from the continued and sustained implementation of demand-side programs under MEEIA?

A. Not at all. Mr. Luebbert shows a progressive increase in generation net plant without noting the nature of the increases. Over the past decade or more, the Company has made investments in its generation fleet to comply with environmental regulations and ensure continued reliable operation. Ameren Missouri also invested over a billion dollars in new wind generation to meet the requirements of the Missouri Renewable Energy Standard in 2020 and 2021. These changes have no relevance to the Company's need for additional generation and the contribution of load reductions from past and future MEEIA programs to the reduced need for even more generation resources than planned. Likewise, the values for UCAP[23] (or the ratio of net generation plant to UCAP) have no bearing on the question of the benefits of load reductions from MEEIA and the ability to avoid the need for even more generation resources than planned. The UCAP values are quite stable from 2015 through 2021, until the retirement of Meramec in 2022.[24] What are we learning from this arithmetic exercise that is relevant to

[22] File No. EO-2023-0136, J. Luebbert Direct, p. 13, ll. 4-7.
[23] UCAP is unforced capacity (i.e., capacity adjusted for forced outages).
[24] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 13, l. 15.

the questions at hand regarding the Company's plans to continue to provide MEEIA programs to its customers? Nothing, as far as I can see.

Q. Mr. Luebbert asserts that the Company's IRP modeling reflects a package of demand-side measures that may not ultimately match what is offered. Is this a shortcoming of the IRP process?

A. No. The Company's IRP analysis relies on a rigorous assessment of demand-side resource potential. The market potential studies conducted by the Company with the help of expert consultants is the result of a months-long effort to assess potential measures for cost-effectiveness and adoption by customers. This effort includes a robust stakeholder process, which includes Staff, OPC and other stakeholders. While it is impossible to precisely predict exactly what measures will be offered over the next twenty years, how incentives will be structured, how effective certain approaches to marketing and promotion will be, and a host of other factors will play out, the process has resulted in robust programs that have saved customers millions of dollars on their bills and produced load reductions that reduce the Company's need for more generation resources than it would otherwise need. Importantly, program details are informed by insights and inputs drawn from the RFP process prior to the Company's MEEIA application filings, as discussed by Company witness Tim Via in his rebuttal testimony. It is also impossible to predict how Staff and other stakeholders will view various elements of proposed MEEIA programs when the Company makes its applications to the Commission for program approval. The programs that result from the application process invariably reflect further input from Staff, OPC and other stakeholders involved in the MEEIA process.

Q. Are you concerned about constraining the scope of MEEIA programs or suspending them altogether?

A. Yes. Ameren Missouri and the entire utility industry are navigating challenging times with respect to ensuring sufficient resources to maintain reliability. Continuing to constrain MEEIA programs, as has been done in prior cycles, means constraining the very load reductions that can reduce the need for new generation. Suspending MEEIA programs altogether would require a major shift in the Company's resource planning to ensure sufficient alternative resources are available to meet customer needs and ensure reliability in both the near term and the long term and would expose customers to approximately $4 billion in additional costs over the next twenty years (on a net present value of revenue requirements["NPVRR"] basis), a situation that is untenable on both counts.

Q. Mr. Luebbert indicates that Ameren Missouri includes other drivers for generation beyond a pure capacity need.[25] Does this diminish the importance of load reductions from MEEIA programs?

A. No, and it shouldn't. It is important to recognize the role those other factors play. The first priority is to ensure reliability. This includes not only capacity, but also energy and a consideration of the ability and flexibility of resources to ensure reliability during the most critical times, such as geographically widespread winter storms of the kind we've seen more frequently in recent years. In ensuring reliability, we also want to ensure affordability. The requirement in the IRP rules that cost to customers, as measured by the NPVRR, be considered the primary selection criterion for utilities in selecting their PRP supports this notion, along with consideration of impacts on rates. We also strive to ensure that we maintain some level of planning flexibility to deal with changing conditions and address risks, such as changes in environmental and climate policy, that may impact resource viability and selection. Far from

[25] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 3, ll. 22-23.

being a weakness in the IRP process, consideration of such factors helps the Company's management to ensure that its resource decisions will be in the best interest of its customers and the public under a variety of future conditions. The Company selected its current PRP on this basis and has demonstrated through its IRP analysis that absent continued implementation of demand-side programs under MEEIA, it would need to add or accelerate roughly 3,600 MW of generation.[26]

Q. Dr. Marke asserts that the Company's second MEEIA cycle did not result in avoided generation because of the Company's long capacity position.[27] Is this assertion accurate?

A. It is accurate to the extent that the Company would not have added generation resources for near-term capacity needs while it was long capacity. However, it is important to note that the load reductions resulting from implementation of MEEIA programs last well into the future. When combined with the load reductions of prior and subsequent MEEIA cycles, this does reduce the Company's long-term needs for generation resources.

IV. STAFF'S NOTION THAT DEMAND-SIDE PROGRAMS CAN BE TIMED TO "SHARPSHOOT" FUTURE RESOURCE NEEDS IS BOTH UNREASONABLE AND UNWISE

Q. How does Staff characterize the proper approach to pursuing demand-side resources through MEEIA programs?

A. In short, Staff suggests that the Company can and should attempt to adjust the implementation of demand-side programs under MEEIA to precisely meet a need for resources

[26] See Table 1.
[27] i.e., the Company's generating capacity was substantially greater than its peak demand and planning reserve margin requirement.

in terms of both timing and magnitude.[28] In essence, Staff is suggesting that utilities try to "sharpshoot" the implementation of demand-side programs.

Q. Why do you believe Staff's suggestion is unreasonable and unwise?

A. It is unreasonable for several reasons. First, load reductions from future programs are estimates. While we've found that these are very good estimates, owing in large measure to the experience and expertise of consultants such as GDS, they are still estimates and are based on expectations of customer adoption. They are therefore subject to the decisions of many thousands of individual customers under uncertain future conditions. Second, MEEIA programs are subject to regulatory risk, including the views and preferences of stakeholders and the potential that the incentives contemplated in the MEEIA statute may not be fully realized. Third, some programs require decisions that do not occur frequently for individual customers – replacing major appliances or heating and cooling equipment. Once the decision is made, it cannot be unmade, so the window of opportunity to improve efficiency has passed. Finally, the broader planning environment is subject to significant uncertainty, and conditions that may have been conducive to implementation of certain measures may change. This is also why such an attempt to sharpshoot MEEIA program implementation is unwise. If we set out to meet a resource need at a certain time and "hold back" implementation of programs to reduce load "just in time" to avoid a specific resource, conditions that accelerate and/or increase the need for resources may arise in such a way that adjusting implementation to meet the greater and/or accelerated need is impossible. We have seen time and time again that such major changes can

[28] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 21, ll. 15-16. Specifically, Mr. Luebbert states that, "Ameren Missouri does not allow the modeling software used in the IRP to select, size, or optimize demand-side programs being included within alternative resource plans."
File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 22, l. 2-4. Specifically, Mr. Luebbert states that, "There are not thresholds included for adding additional demand-side resources near times of greatest need, nor slowing demand-side management when the timing or size of supply-side resources are not effectively altered."

occur – the promulgation of expensive regulations, the push toward electrification, onshoring of industry, and others. For example, just imagine if we were following Staff's approach at a time when we had determined that our nearest capacity resource need was ten years out, when a coal-fired resource was planned for retirement. Further assume that five years of savings from Demand-Side Management ("DSM") programs could offset that need. If we tried to "sharpshoot" the need as Staff would have us do, we might wait five years to implement DSM, again assuming that five years of programs were sufficient to offset the need. Now imagine that a new greenhouse gas rule was implemented and the retirement of the coal-fired resource, and therefore the need, was accelerated by five years with the stroke of the regulatory pen. If programs had been suspended and there was no program infrastructure, supplier networks, or delivery channels established, there would be no way to accelerate the DSM savings to meet the resource need that was accelerated, and we would be left either short of the capacity needed to reliably meet our load, or we would be rapidly developing a more expensive alternative capacity resource that could replace the non-existent demand-side savings. Implementation of MEEIA programs cannot be viewed through the lens of short-term paybacks under a specific set of assumptions at a given moment. Rather, it must be viewed as a commitment to capturing cost-effective savings for customers and load reductions that reduce the need for future generation resources whenever that need might be. This is the driving force behind the concept of integrated resource planning itself, to evaluate demand-side resources and supply-side resources side-by-side over a long period of time to minimize costs and risks for utilities and their customers, and it is the driving force behind the passage of MEEIA, which established as state policy the pursuit of "all cost effective demand-side savings."

Q. Has Ameren Missouri evaluated plans that seek to meet needs precisely when they occur?

A. Yes. In the Company's 2020 IRP, two demand-side portfolios were constructed on this basis and broadly referred to as Dynamically Optimized Portfolio Extension ("DOPE"). Two alternative resource plans, one with each of the two DOPE portfolios, were analyzed. While they were able to result in some generation/resource deferral, they did not achieve the same level of generation avoidance or deferral that was achieved by a comparable plan with the RAP portfolio, and they resulted in NPVRR costs to customers that were roughly $700 million higher.[29]

Q. Does Ameren Missouri's most recent IRP analysis indicate savings to customers from the continued and sustained implementation of demand-side programs under MEEIA?

A. Yes. Ameren Missouri's analysis of plans with (Plan C) and without (Plan I) show that customers can expect to save over $4 billion dollars over the next 20 years on an NPVRR basis as shown in Table 2 below. Note that this is the case regardless of the assumptions used for carbon price.

Table 2 – NPVRR comparison for plans with and without demand-side resources

Alternative Resource Plans		NPVRR Without Better Info	Carbon Price		
			Low	Base	High
C	RAP - Renewable Expansion	81,985	81,748	81,937	82,243
I	No Additional DSM	86,182	85,960	86,145	86,406
	Difference (Plan I - Plan C)	4,197	4,211	4,208	4,163

[29] Ameren Missouri 2020 IRP Chapter 10 – Strategy Selection, p. 28, Table 10.8.

Q. Do customers still save money if an earnings opportunity for the Company is included?

A. Yes. Even with an earnings opportunity for the Company that is based on the full recovery of lost earnings from avoided generation investments, customers realize savings of $3.752 billion on an NPVRR basis under Plan C compared to Plan I.[30]

V. THE COMPANY'S DEVELOPMENT AND APPLICATION OF AVOIDED CAPACITY COSTS IS APPROPRIATE

Q. What do Staff witnesses allege about the Company's application of avoided capacity costs?

A. Mr. Luebbert makes a number of assertions regarding avoided capacity costs:

- Avoided capacity costs result in preferential treatment of demand-side resources relative to supply-side resource.[31]
- Generic avoided cost assumptions can't be used to evaluate different portfolios.[32]
- Renewable energy resources have very low avoidable costs.[33]

Mr. Luebbert goes on to suggest an alternative approach to determining avoided capacity costs that relies on the "sharpshooting" notion I discussed earlier. In addition, Ms. Lange suggests that a portion of avoided costs are "cancelled out" by the inclusion of an

[30] Value is reflected in the updated workpapers provided in connection with updated IRP documents filed by the Company on April 2, 2024. See file "PVRR_Plan I rev_Confidential.xlsx," tab 'RevReq-Incentives', cells CA4 and CA10.
[31] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 21, ll. 3-14.
[32] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 9, ll. 17-18.
[33] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 17, l. 17.

earnings opportunity that is based on full recovery of lost earnings from supply-side investments.

Q. Taking the last part first, how do you respond to Ms. Lange's assertions regarding avoided capacity costs and earnings opportunity?

A. I think the concept is sound in theory, and it is relevant to the extent that the Company is awarded an earnings opportunity that, over time, is designed to recover the full amount of lost earnings from supply-side investments that would otherwise be needed, as Staff suggests would be appropriate. However, as both Mr. Lozano and Mr. Wills note, the Company's opportunity for earnings has often fallen well short of the foregone earnings from supply-side investments. Beyond that, and as I mentioned previously, the Company's IRP analysis shows that customers would save over $3.7 billion through the continued and sustained implementation of MEEIA programs even if the earnings opportunity were designed to recover the full amount of lost earnings from supply-side alternatives. Clearly, whatever the level of MEEIA earnings opportunity and to whatever extent it results in full recovery of the lost earnings opportunity from alternative supply-side investments, there is still a great deal of cost avoided for such alternative supply-side investments that results from the continued and sustained implementation of demand-side programs under MEEIA and is not cancelled out.

Q. Mr. Luebbert suggests that avoided capacity costs are applied in a way that gives a preference for demand-side resources relative to supply-side resources. Is this true?

A. No. Unfortunately, this stems from apparent confusion on the part of Staff regarding the application of avoided capacity costs used for screening demand-side measures and programs versus the use of market-based capacity prices in the evaluation of alternative resource plans in the IRP. I will attempt to dispel this confusion. In short, avoided capacity costs are used as a stand-in for the *cost* of supply-side resources with which they are "competing." In contrast, assumed market capacity prices are used to determine the expected *revenue* to be realized from *both* demand-side resources *and* supply-side resources in the Midcontinent Independent System Operator ("MISO") market. Figure 1 below provides a simple illustration of how this works.

Figure 1 – Simplified example for application of avoided capacity costs and market capacity prices

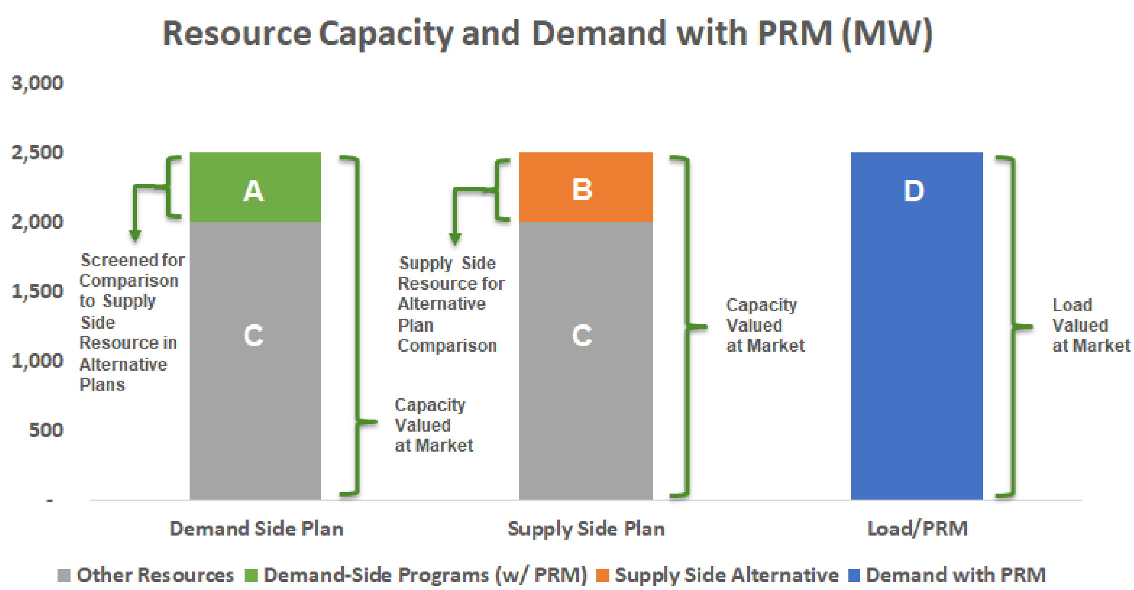

Figure 1 shows two different alternative plans – a Demand-Side Plan and a Supply-Side Plan – in simple form. Both include the same amount of other resources ("C"), which are assumed to be the same resources for both alternative plans. The Demand-Side Plan also includes demand resources ("A"), which are grossed up for the associated avoided planning reserve margin. Alternatively, the Supply-Side Plan includes additional supply-side resources ("B") in an amount equal to the demand-side resources in the Demand-Side Plan. Both plans are assumed to exactly meet the load and planning reserve margin requirement ("D").

During the screening process for demand-side resources, we use avoided capacity costs that reflect the approximate *cost* of supply-side resource alternatives to the demand-side programs. It is important during screening that we do not grossly underestimate the cost of supply-side alternatives. If we do, then we may be leaving money on the table for customers in the form of savings that could otherwise be achieved by substituting demand-side resources at a cost that is still below the cost of the supply-side alternative that would otherwise have to be implemented.

Having designed these two alternative resource plans, we move to the integration and risk analysis in the IRP. For both plans, we value the capacity provided by all of the resources in each plan at the market price of capacity. This is the *revenue* that is realized by these resources (A, B and C in Figure 1), with *both* supply-side *and* demand-side valued equally, in the MISO market. At the same time, we assess the *cost* of serving load in the MISO market, again at the assumed market price of capacity. In this simple example, the cost of load is the same, and the total market revenue for resources is the same. The only difference is the cost of the different resources in the two plans. Because avoided costs representing the expected cost of competing supply-side resources was used for screening, the potential demand-side resources were not underestimated as they would be if much lower market capacity prices had been applied in screening.

To summarize, through the screening process we want to ensure that we include all demand-side resources that are competitive with supply-side resources so that we can fairly evaluate both demand-side resources and supply-side resources on equal footing through the IRP integration and risk analysis.

Q. Your example treats load reductions as resources that receive revenue in the MISO capacity market. Don't those load reductions simply reduce load and therefore costs rather than realize capacity revenues?

A. I treat the demand-side resource load reductions as a resource for simplicity of comparison to the supply-side alternative. If we looked at the Demand-Side Plan with demand-side load reductions applied to load rather than resources, the economic result would be exactly the same – we would reduce the resource revenue by the market price of capacity applied to the demand-side resource (including planning reserve margin), and we would reduce the cost to load by the exact same amount.

Q. Mr. Luebbert suggests that the avoided capacity costs should include a seasonal element, as represented in the Company's market capacity price assumptions. Is that correct?

A. No. As I explained with the simple example above, the avoided costs used for screening demand-side resources are a stand-in for *cost* of the supply-side resources with which they are competing, and the market prices of capacity are used to determine the revenue for resources and the cost of load in the IRP integration and risk analysis. It would make no sense to apply any seasonality to a supply-side investment – if deployed, it is available all year, and its costs for the entire year are included in rates. Separately, the market price of capacity is applied to all resources and load in an equivalent manner, so demand-side resource load reductions realize economic value (whether conceived as revenue as a resource or reduced cost as a reduction to load) based on the load reductions produced during a season and the capacity price for that season. I would be happy to have a discussion with any parties to clear up any confusion that might remain.

Q. Mr. Luebbert offers an alternative approach to calculating avoided capacity costs. Do you find it compelling?

A. No. As I mentioned previously, the concept is based on the notion that utilities can and should attempt to "sharpshoot" future resource needs. It also presumes that the utility knows what resource it stands to avoid before it has performed its IRP analysis. The approach effectively works backward from an outcome that is presumed to be known, provides no greater accuracy in screening demand-side resources, and is irrelevant to the evaluation of alternative resource plans. The way we are approaching avoided costs appropriately captures sufficient cost-effective potential for use in alternative resource plan comparisons as part of the Company's IRP analysis. And for the reasons I just described, the Company's separate application of market capacity prices for the comparison of alternative resource plans is appropriate and results in valuing supply and demand-side resources equally.

Q. Mr. Luebbert raises the question of avoidable costs for renewable resources. Is this relevant?

A. I do not believe it is. The Company's portfolio transition has been described at length in its IRP filings in 2020, 2022, and 2023, and in other cases before the Commission. It should be apparent from the Company's approach to renewable resources and MEEIA that the Company is not seeking to avoid renewable resources with MEEIA programs given their relative cost and risk advantages compared to supply-side resources. Rather, the Company is evaluating demand-side resources against conventional, dispatchable supply-side resources, primarily because they are more appropriately viewed as capacity resources.

VI. THE COMPANY'S DEVELOPMENT AND APPLICATION OF AVOIDED T&D COSTS IS APPROPRIATE

Q. What is Staff's criticism regarding the Company's use of assumptions for avoided T&D costs?

A. Simply put, Staff does not believe that avoided T&D costs exists unless one can point to a specific planned line, substation, transformer, breaker, pole, or other piece of equipment that we would otherwise deploy in the absence of MEEIA programs.[34] Staff completely dismisses the notion of system-wide avoided costs.

Q. Is it a common practice to include system-wide avoided T&D costs in cost effectiveness analyses of demand-side resources?

A. Yes. One example comes from New England, where comprehensive studies of avoided costs, including system-wide avoided T&D costs, have been performed and used for nearly two decades. Synapse Energy Economics ("Synapse"), a consulting firm with experience and expertise in utility planning and demand-side program analysis, has conducted these periodic studies starting in 2007.[35] In the most recent Avoided Energy Supply Cost study, published in February of this year, Synapse includes discussion of a commonly-used approach to estimating system-level avoided T&D costs.[36] Specifically, Synapse describes the following steps:

- Step 1: Select a time period for the analysis, which may be historical, prospective, or a combination of the two.

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[34] File No. EO-2023-0136, J. Luebbert Direct Testimony, p. 8, ll.13-14 and p. 9, ll. 9-12.
[35] Synapse has performed and published Avoided Energy Supply Costs ("AESC") studies in 2007, 2009, 2011, 2013, 2018, 2021, and 2024. See more about their work at https://www.synapse-energy.com/avoided-energy-supply-costs-new-england-aesc
[36] See Schedule MM-R1 – Synapse 2024 AESC, pp. 270-282.

- Step 2: Determine the actual or expected relevant load growth in the analysis period, in MW.
- 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 O&M of the equipment to derive the total avoidable cost in $ per kW-year.

Q. Has Ameren Missouri used such an approach for its estimation of avoided T&D costs?

A. Yes. Ameren Missouri has been using a similar approach since its 2011 IRP. Since that time, the Company has modified its approach depending on analysis tool capabilities and data availability. Figure 2 below shows the steps used to calculate avoided transmission costs as reflected in the Company's 2023 DSM Market Potential Study ("MPS").

Figure 2 – Ameren Missouri 2023 MPS avoided transmission cost calculation

A		660		Load Change During Period (MW)
B	$	15.5	From Analysis	Avoidable 8-year Capacity Projects Budget (Million2020$)
C	$	1.938	B/8	Average Annual Capacity Projects Budget (Million2020$)
D		9.09%		Levelized Fixed Charge Rate
E	$	0.1761	C*D	Levelized Average Annual Capacity Projects Budget (Million2020$)
F	$	176,119	E*1,000,000	Levelized Average Annual Capacity Projects Budget (2020$)
G		82,500	A/8*1000	Average Annual Transmission System Growth over 8-year period (kw)
H	$	2.27	F/G	Avoided Transmission Cost (2020$/kw-year)
I	$	25	H/D	Capex/kw
J	$	24,922	I*1000	Capex/MW
K	$	2,056,091	J*A/8	Capex for Load Change

Because Ameren Missouri has models capable of assessing system-level transmission infrastructure needs, the same models used to determine infrastructure needs for new or retiring generation resources, the Company used this modeling capability to assess the infrastructure needs for a level of load growth over a defined period – 1 percent annual growth from 2020-2028. In doing so, we are able to estimate the costs associated with such load growth and therefore the cost per kilowatt ("kW") of change in load. This cost per kW is then applied in the demand-side resource screening process as part of the cost-effectiveness analysis.

In contrast to the modeling capabilities used for assessing transmission infrastructure needs, Ameren Missouri does not have (nor is it aware of) modeling tools that assess system-level infrastructure needs at the distribution level. The reason seems obvious – the distribution system is much more granular and varied than the transmission system. Another complication arises in determining avoidable costs in that Ameren Missouri has been successfully implementing MEEIA programs for over a decade, and thus has had little to no system-level load growth on which to base such an estimate. This is evident from Figure 2 on page 10 of Mr. Wills' rebuttal testimony. This should not, however, be interpreted to mean that there are no system-level avoided distribution costs. Indeed, it seems unnecessary to state that increasing load would certainly lead to the need for more infrastructure at the distribution level as it does at the transmission level. To solve this issue, Ameren Missouri has based its avoided distribution costs on the totality of system level costs relative to load. Figure 3 below shows Ameren Missouri's calculation of avoided distribution costs used in its 2023 MPS.

Figure 3 – Ameren Missouri 2023 MPS avoided distribution cost calculation

A		7,362		2019 WN Peak Load
B		5,227,462		Gross Distribution Plant
C		2,697,670		Accumulated Depreciation
D	$	2,529,791	B-C	Net Distribution Plant ($1000's) as of 12/31/2019
E		9.25%		Levelized Fixed Charge Rate (LCFR)
F	$	32	D*E/A	Distribution Cost of Load ($/kW)
G		60%		Condition/Reliability Replacement Factor
H	$	19.07	F*G	Avoided Distribution Cost (2020$/kW-year)
I	$	206	H/E	Capex/kW
J	$	206,177	I*1,000	Capex/MW

Q. Could Ameren Missouri also calculate avoided distribution costs based on avoidance of specific projects?

A. I think such a calculation could only be done in the very short-term given the shorter-term nature of planning and budgeting for distribution projects. Certainly, there are opportunities to evaluate alternatives to "wires" projects, but they can be limited as well as being very short-term in nature. The Company's approach to system-level avoided distribution costs recognizes the long-term nature of load reductions and the varied nature of system needs across the Company's service territory.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 4th Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA.	))))	File No. EO-2023-0136

AFFIDAVIT OF MATTHEW MICHELS

**STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)**

Matthew Michels, being first duly sworn on his oath, states:

My name is Matthew Michels, and hereby declare on oath that I am of sound mind and lawful age; that I have prepared the foregoing *Rebuttal Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

Matthew Michels

SWORN TO BEFORE ME, the undersigned Notary Public on this 26th day April, 2024.

Notary Public

My Commission Expires: 5/10/2027

ERIN KEENOY
Notary Public - Notary Seal
State of Missouri
Commissioned for St. Louis City
My Commission Expires: May 10, 2027
Commission Number: 23459735

Avoided Energy Supply Components in New England: 2024 Report

Prepared for AESC 2024 Study Group

February 7, 2024

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Schedule MM-R1

Table of Contents

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

TABLE OF FIGURES

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

TABLE OF TABLES

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

Schedule MM-R1

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Schedule MM-R1

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
DER	Distributed energy resource
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
LNG	Liquefied natural gas
LDC	Local distribution company
LMP	Locational marginal price
LSE	Load-serving entity
LAUF	Lost and unaccounted for (gas)
MMcf	Million cubic feet
Net ICR	Net installed capacity requirement
NWA	Non-Wires Alternative
PTF	Pool transmission facility
REC	Renewable energy certificate
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable natural gas
RPS	Renewable portfolio standard
STEO	Short-Term Energy Outlook
T&D	Transmission and distribution
VoLL	Value of lost load

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Schedule MM-R1

1. EXECUTIVE SUMMARY

This document is the 2024 Avoided Energy Supply Component (AESC) Study (AESC 2024). AESC 2024 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 2024 or later years. AESC 2024 features six 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 2024 or later years.
- **Counterfactual #2:** A future in which program administrators continue to install new energy efficiency resources and active demand management resources, but do not install any new building electrification resources in 2024 or later years.
- **Counterfactual #3:** A future in which program administrators continue to install new building electrification resources and active demand management resources, but do not install any new energy efficiency resources in 2024 or later years.
- **Counterfactual #4:** A future in which program administrators continue to install new energy efficiency resources and building electrification resources, but do not install any new active demand management resources in 2024 or later years.
- **Counterfactual #5:** A future in which program administrators continue to install new energy efficiency, active demand management, and building electrification resources.
- **Counterfactual #6:** A future in which program administrators continue to install new energy efficiency, active demand management, and building electrification resources, except for all behind-the-meter storage resources.

Because each AESC counterfactual represents a hypothetical future that lacks some amount of anticipated demand-side measures, AESC 2024 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 the two sensitivities modeled in the AESC 2024 Study (see Chapter 12 for more information).

Schedule MM-R1

As in previous AESC studies, this study examines avoided costs of energy, capacity, RPS compliance, natural gas, fuel oil, other fuels, other environmental costs, and demand reduction induced price effects (DRIPE). Also, AESC 2024 relies upon a combination of models to estimate each one of these avoided costs for each future year. As in AESC 2021, 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 2024 dollars, the AESC 2024 Study estimates that direct avoided wholesale energy costs are approximately 5 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 AESC 2021, we find:

- Generally higher avoided costs of energy, due to higher projections of natural gas prices in the near term and a delayed completion of clean energy electric generating resources, relative to the assumptions used in AESC 2021.

- Generally higher avoided costs of capacity due to higher projections of peak demand, a delayed completion of clean energy electric generating resources, relative to the assumptions used in AESC 2021, and greater numbers of exogenously assumed near-term power plant retirements.

- Generally lower avoided costs of natural gas, based on lower long-term projections of wholesale natural gas prices. Although natural gas prices are projected to be higher in the near term, they are projected to be lower in the mid to long term.

- 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 increases in RPS target obligations, higher expected increases in load due to electrification, and increased costs for clean energy generating resources due to changes in the supply chain.

- Generally similar values for energy and capacity DRIPE, due to a variety of shifts in underlying parameters (e.g., changes in energy prices, capacity market structure, load, and hedging assumptions) that tend to offset one another.

- Generally higher costs related to non-embedded environmental regulations due to updates to underlying data sources.

- Lower avoided costs for pooled transmission facility (PTF) costs, as a result of a switch to a more detailed forward-looking methodology.

- Generally lower avoided costs for reliability, due to a lower estimate for value of lost load (VoLL) and a flatter capacity market supply curve in the near term.

Schedule MM-R1

AESC 2024 provides detailed projections of avoided costs by year for an initial 27-year period based on modeling (2024 through 2050), and a second period based on extrapolation of values from this first period (2051 through 2060).[1] All values in this document are described in terms of real 2024 dollars, unless noted otherwise. In many cases, we provide 15-year (2024–2038) 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 2024 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.

After developing the scope for the 2024 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.

Schedule MM-R1

Study sponsors for the AESC 2024 Study include:

- Avangrid (Berkshire Gas Company, United Illuminating, Southern Connecticut Gas, and Connecticut Natural Gas)
- Cape Light Compact
- Efficiency Maine
- Eversource (Connecticut Light and Power, NSTAR Electric and Gas Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, Yankee Gas, and Columbia Gas of Massachusetts)
- Liberty Utilities
- National Grid USA
- New Hampshire Electric Co-op
- PPL Electric Services (Rhode Island Energy)
- Unitil (Fitchburg Gas and Electric Light Company, Unitil Energy Systems, Inc. and Northern Utilities)
- Vermont Energy Investment Corporation/Efficiency Vermont

Other parties represented in the Study Group include:

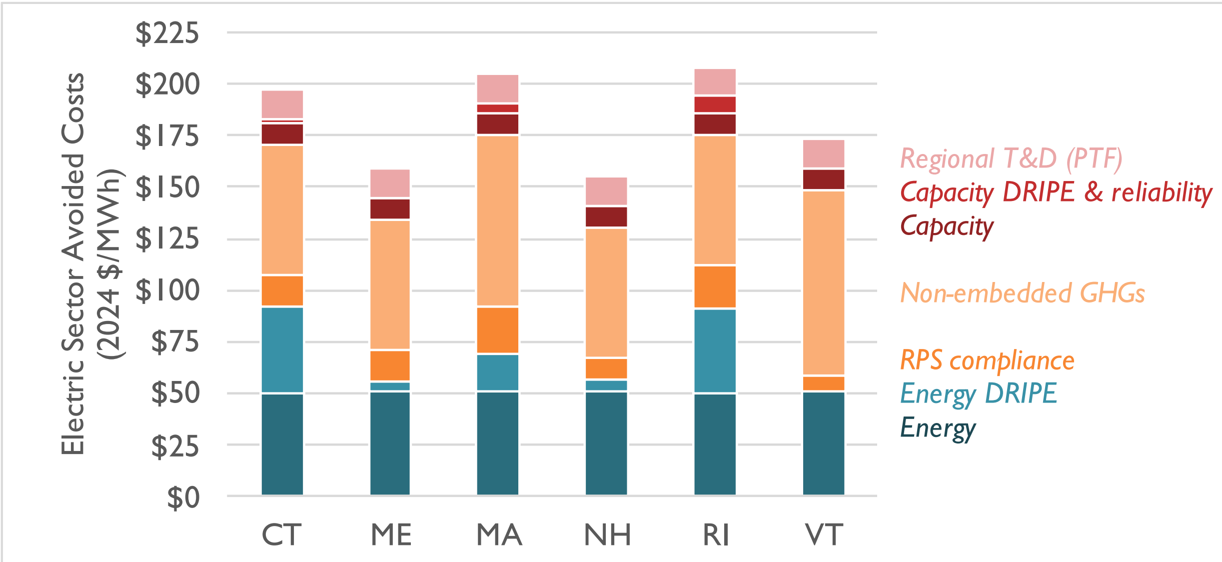
- Acadia Center
- Burlington Electric Department
- Connecticut Department of Energy and Environmental Protection
- Connecticut Energy Efficiency Board
- Maine Public Utilities Commission
- Massachusetts Energy Efficiency Advisory Council
- Massachusetts Department of Public Utilities
- Massachusetts 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 Department of Environmental Services
- New Hampshire Department of Energy
- Rhode Island Division of Public Utilities and Carriers
- Rhode Island Office of Energy Resources
- Vermont Department of Public Service
- Vermont Gas

1.2. Summary of avoided costs

The following section provides a summary of the avoided costs for each category of costs calculated under AESC 2024. 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. Figure 1 and Table 1 provide illustrative comparisons of the avoided costs for a hypothetical energy efficiency measure, for each of the six New England states. This study provides costs at the wholesale level, rather than at the retail level, and only for Counterfactual #1. Historically, each state has tabulated avoided costs in slightly different ways;

Figure 1 and Table 1 provide illustrative comparisons of the avoided costs from AESC 2024 if all six states continued to use the same tabulation method they used in their most recent plan filings.[2]

Figure 1. Illustrative application of AESC 2024 wholesale avoided costs (Counterfactual #1) to a hypothetical energy efficiency measure



Notes: Major differences among the states include modeling differences with respect to energy, capacity, and other values, as well as differences in terms of tabulation (e.g., in terms of how DRIPE is counted or marginal emission rates are calculated), and in terms of which avoided costs are applied within certain categories (e.g., whether a social cost of greenhouse gas is being used, versus some other approach for estimating non-embedded greenhouse gas costs). All avoided costs are tabulated based on each state's historical method of tabulation. The sole exception is non-embedded costs in NH, where Study Group members have directed AESC to use the New England electric-sector MAC, contingent upon the NH Evaluation, Measurement, and Verification discussion and approval. Additional information on how each component is assembled can be found in the notes of Table 2. In this figure, for the states that utilize a social cost of greenhouse gases (Massachusetts and Vermont), a 2 percent discount rate is used.

[2] Note that both Figure 1 and Table 1 (as well as subsequent tables) include some categories of avoided costs that are measured in dollar-per-kWh terms, and categories of avoided costs measured in dollar-per-kW terms. To provide an illustrative comparison, we converted the dollar-per-kW values into dollar-per-kWh values. We do this by dividing the dollar-per-kW input value by (8,760 hours x a load factor), where the "load factor" represents how costs incurred in a peak hour might be spread across all hours of the year. For AESC 2024, we utilize a load factor of 56 percent, which we derive by dividing the annual 2024 GWh load in Counterfactual #1 by the summer coincident peak GW load in that same year and counterfactual x 8,760 hour).

Schedule MM-R1

Table 1. Illustrative avoided costs for hypothetical energy efficiency measure installed in each New England state, Counterfactual #1

		CT	ME	MA	NH	RI	VT	Notes
Energy	*2024 $/MWh*	$50	$51	$50	$51	$50	$51	*4*
RPS compliance	*2024 $/MWh*	$16	$15	$23	$11	$21	$7	*4, 5*
Elec. energy, cross-DRIPE	*2024 $/MWh*	$42	$5	$19	$5	$41	$0	*6*
GHG non-embedded	*2024 $/MWh*	$63	$63	$83-143	$63	$63	$90-152	*4,7,8,13*
Energy subtotal	***2024 $/MWh***	**$170**	**$134**	**$175-235**	**$130**	**$175**	**$149-210**	
Capacity	*2024 $/kW-year*	$52	$52	$53	$52	$54	$52	*9*
Capacity DRIPE	*2024 $/kW-year*	$9	$3	$24	$3	$41	$0	*9,10*
Regional Transmission (PTF)	*2024 $/kW-year*	$69	$69	$69	$69	$69	$69	*11*
Value of reliability	*2024 $/kW-year*	<$1	<$1	<$1	<$1	<$1	<$1	*9*
Capacity subtotal	***2024 $/kW-year***	**$130**	**$123**	**$146**	**$124**	**$163**	**$120**	-
Capacity subtotal	***2024 $/MWh***	**$26**	**$25**	**$30**	**$25**	**$33**	**$25**	***12***
Total	***2024 $/MWh***	**$197**	**$159**	**$205-265**	**$155**	**$208**	**$173-235**	**-**

Notes:
[1] All costs are shown levelized over 15 years. All costs are shown for Massachusetts and tabulated using the historical method in Massachusetts. Costs have not been adjusted for risk premiums or T&D loss factors.
[2] All avoided costs are estimated based on the methods states have previously used to tabulate avoided costs. These methods may change in the future.
[3] AESC 2024 data is from the AESC 2024 User Interface. AESC 2024 values are levelized over 2024–2038, using a real discount rate of 1.74%.
[4] Energy, energy DRIPE, and GHG non-embedded costs are based on annual average numbers.
[5] Costs of RPS compliance are the sum of the per-MWh cost for all RPS programs active in this state.
[6] Electric energy and cross-DRIPE include intrazonal energy DRIPE, E-G DRIPE, and E-G-E DRIPE. Interzonal effects are not included.
[7] GHG non-embedded costs a 2% social cost of carbon for AESC 2021. For AESC 2024, GHG non-embedded costs for Connecticut, Maine, New Hampshire, and Rhode Island are based on a marginal abatement cost derived from the electric sector; GHG non-embedded costs for Massachusetts and Vermont are shown based on a range of a range of social cost of GHGs representing 1.5% and 2% discount rates. AESC 2024 social cost of GHG costs include impacts from CO2, CH4, and N2O pollution and exclude impacts from upstream emissions. The AESC 2024 report recommends the use of the EPA-derived SC-GHG, which includes costs for 1.5% and 2% discount rates.
[8] GHG non-embedded costs subtract embedded costs (RGGI, state-specific costs in Massachusetts from the social cost of GHGs.
[9] Capacity, capacity DRIPE, and reliability values are shown for cleared values only. Uncleared values are not included.
[10] Capacity DRIPE values include intrazonal effects only. Interzonal effects are not included.
[11] "Regional Transmission (PTF)" values only include regional transmission costs. This cost does not include more localized transmission costs or any distribution costs. These other avoided costs may be specifically calculated in each jurisdiction.
[12] Capacity values are converted to energy values using a load factor of 56%.
[13] All avoided costs are tabulated based on each state's historical method of tabulation. The sole exception is non-embedded costs in NH, where the Study Group members have directed us to use the New England electric-sector MAC, contingent upon the NH Evaluation, Measurement, Verification discussion and approval.

Next, Table 2 provides illustrative avoided cost components for electricity for the same hypothetical energy efficiency measure installed in Massachusetts for Counterfactual #1, and how these components compare to the avoided costs from the previous AESC 2021 study. This table is provided for illustrative

Schedule MM-R1

purposes only. Avoided cost values will be different for each measure and will, in some cases, be very different for other measure types (such as building electrification, behind-the-meter storage, or demand response). The value will also differ among states. Costs are provided at the wholesale level, rather than at the retail level.

Note that comparisons between 15-year levelized costs in AESC 2024 and AESC 2021 are not directly "apples-to-apples." While both calculations display levelized costs over 15 years (in real 2024 dollars), each levelization calculation is done over two different 15-year periods (2024–2038 for AESC 2024, and 2021–2035 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. Analogous tables for other states and other counterfactuals can be found in the accompanying AESC 2024 slide deck, and in the Excel-based *AESC 2024 User Interface*. In general, we observe similar values for energy and capacity, higher values for energy DRIPE, RPS compliance, and GHG non-embedded costs, and lower values for regional transmission and distribution (T&D) and capacity DRIPE relative to AESC 2021.

Table 2. Illustrative avoided costs for hypothetical energy efficiency measure installed in Massachusetts, AESC 2024 Counterfactual #1 versus AESC 2021 Counterfactual #1

		AESC 2021	AESC 2024	Differ-ence	% Differ-ence	Notes
Energy	*2024 $/MWh*	$46	$50	$4	9%	*4*
RPS compliance	*2024 $/MWh*	$12	$23	$10	84%	*4, 5*
Electric energy and cross-DRIPE	*2024 $/MWh*	$13	$19	$6	42%	*6*
GHG non-embedded	*2024 $/MWh*	$51	$83-143	$32-92	63-180%	*4,7,8*
Energy subtotal	***2024 $/MWh***	**$123**	**$175-235**	**$52-112**	**43-91%**	
Capacity	*2024 $/kW-year*	$48	$53	$6	12%	*9*
Capacity DRIPE	*2024 $/kW-year*	$19	$24	$5	27%	*9,10*
Regional Transmission (PTF)	*2024 $/kW-year*	$95	$69	-$26	-28%	*11*
Value of reliability	*2024 $/kW-year*	$1	<$1	<-$1	-55%	*9*
Capacity subtotal	***2024 $/kW-year***	**$162**	**$146**	**-$16**	**-10%**	-
Capacity subtotal	***2024 $/MWh***	**$33**	**$30**	**-$3**	**-10%**	***12***
Total	***2024 $/MWh***	**$156**	**$205-265**	**$49-109**	**32-70%**	-

Notes:
[1] All costs are shown levelized over 15 years. All costs are shown for Massachusetts and tabulated using the historical method in Massachusetts. Costs have not been adjusted for risk premiums or T&D loss factors.
[2] AESC 2021 data is from the AESC 2021 User Interface. AESC 2021 values are levelized over 2021–2035, using a real discount rate of 0.81%. 2021 costs have been converted to 2024 dollars.
[3] AESC 2024 data is from the AESC 2024 User Interface. AESC 2024 values are levelized over 2024–2038, using a real discount rate of 1.74%.
[4] Energy, energy DRIPE, and GHG non-embedded costs are based on annual average numbers.
[5] Costs of RPS compliance are the sum of the per-MWh cost for all RPS programs active in this state.
[6] Electric energy and cross-DRIPE include intrazonal energy DRIPE, E-G DRIPE, and E-G-E DRIPE. Interzonal effects are not included.
[7] GHG non-embedded costs a 2% social cost of carbon for AESC 2021. For AESC 2024, GHG non-embedded costs for

Schedule MM-R1

Connecticut, Maine, New Hampshire, and Rhode Island are based on a marginal abatement cost derived from the electric sector; GHG non-embedded costs for Massachusetts and Vermont are shown based on a range of a range of social cost of GHGs representing 1.5% and 2% discount rates. AESC 2024 social cost of GHG costs include impacts from CO2, CH4, and N2O pollution and exclude impacts from upstream emissions. The AESC 2024 report recommends the use of the EPA-derived SC-GHG, which includes costs for 1.5% and 2% discount rates.
[8] GHG non-embedded costs subtract embedded costs (RGGI, state-specific costs in Massachusetts) from the social cost of GHGs.
[9] Capacity, capacity DRIPE, and reliability values are shown for cleared values only. Uncleared values are not included.
[10] Capacity DRIPE values include intrazonal effects only. Interzonal effects are not included.
[11] "Regional Transmission (PTF)" values only include regional transmission costs. This cost does not include more localized transmission costs or any distribution costs. These other avoided costs may be specifically calculated in each jurisdiction.
[12] Capacity values are converted to energy values using a load factor of 56%.

Next, Table 3 shows a comparison of avoided costs across all counterfactuals. This is again an illustrative comparison for a hypothetical energy efficiency measure installed in Massachusetts, just as in the previous tables and figures. In general, counterfactuals with lower levels of load (like Counterfactual #2) have lower costs of RPS compliance and lower energy prices. Counterfactuals with lower reserve margins tend to have lower capacity prices. Reserve margins are calculated based on the ratio of firm capacity to peak demand; between a pair of scenarios, lower reserve margins may indicate lower levels of peak demand or higher levels of firm capacity.

Table 3. Illustrative avoided costs for hypothetical energy efficiency measure installed in Massachusetts, all AESC 2024 counterfactuals

		CF#1	CF#2	CF#3	CF#4	CF#5	CF#6
Energy	*2024 $/MWh*	$50	$47	$51	$51	$50	$50
RPS compliance	*2024 $/MWh*	$23	$23	$24	$22	$23	$23
Electric energy and cross-DRIPE	*2024 $/MWh*	$19	$18	$19	$19	$19	$19
GHG non-embedded	*2024 $/MWh*	$83-143	$83-143	$83-143	$83-143	$83-143	$83-143
Energy subtotal	***2024 $/MWh***	**$175-235**	**$171-231**	**$177-237**	**$176-236**	**$175-235**	**$175-234**
Capacity	*2024 $/kW-year*	$53	$40	$40	$56	$49	$59
Capacity DRIPE	*2024 $/kW-year*	$24	$25	$24	$48	$31	$73
Regional Transmission (PTF)	*2024 $/kW-year*	$69	$69	$69	$69	$69	$69
Value of reliability	*2024 $/kW-year*	<$1	<$1	<$1	<$1	<$1	$1
Capacity subtotal	***2024 $/kW-year***	**$146**	**$133**	**$134**	**$174**	**$149**	**$201**
Capacity subtotal	***2024 $/MWh***	**$30**	**$27**	**$27**	**$35**	**$30**	**$41**
Total	***2024 $/MWh***	**$205-265**	**$198-258**	**$204-264**	**$211-271**	**$205-265**	**$216-275**

Notes:
[1] All costs are shown levelized over 15 years. Costs have not been adjusted for risk premiums or T&D loss factors.
[2] All costs are illustrative; they are based on costs for Massachusetts and tabulated using the historical method in Massachusetts.
[3] AESC 2024 data is from the AESC 2024 User Interface. AESC 2024 values are levelized over 2024–2038, using a real discount rate of 1.74%.
[4] Energy, energy DRIPE, and GHG non-embedded costs are based on annual average numbers.
[5] Costs of RPS compliance are the sum of the per-MWh cost for all RPS programs active in this state.

Schedule MM-R1

[6] Electric energy and cross-DRIPE include intrazonal energy DRIPE, E-G DRIPE, and E-G-E DRIPE. Interzonal effects are not included.
[7] GHG non-embedded costs a 2% social cost of carbon for AESC 2021. For AESC 2024, GHG non-embedded costs for Connecticut, Maine, New Hampshire, and Rhode Island are based on a marginal abatement cost derived from the electric sector; GHG non-embedded costs for Massachusetts and Vermont are shown based on a range of a range of social cost of GHGs representing 1.5% and 2% discount rates. AESC 2024 social cost of GHG costs include impacts from CO2, CH4, and N2O pollution and exclude impacts from upstream emissions. The AESC 2024 report recommends the use of the EPA-derived SC-GHG, which includes costs for 1.5% and 2% discount rates..
[8] GHG non-embedded costs subtract embedded costs (RGGI, state-specific costs in Massachusetts) from the social cost of GHGs.
[9] Capacity, capacity DRIPE, and reliability values are shown for cleared values only. Uncleared values are not included.
[10] Capacity DRIPE values include intrazonal effects only. Interzonal effects are not included.
[11] "Regional T&D (PTF)" values only include regional transmission costs. This cost does not include more localized transmission costs or any distribution costs. These other avoided costs may be specifically calculated in each jurisdiction.
[12] Capacity values are converted to energy values using a load factor of 56%.

Natural gas

In the near term, Henry Hub natural gas prices in AESC 2024 are higher than in AESC 2021, reflecting the elevated gas prices beginning in the second half of 2021, lasting throughout 2022 (see Table 4). However, in the long run, the AESC prices from 2030 to 2050 drop to an average of $3.71 per MMBtu, which is close to the long-run average in AESC 2021. The elevated prices in the near-term driven by restricted supply due to economic conditions, weather-related declines in U.S. gas production, and increased weather-driven demand in the United States, along with increased LNG exports to Europe. We note that gas prices are from data available at the time of this study, including near-term NYMEX data published in Fall 2023 and mid- and long-term price projections published by the U.S. Energy Information Administration (EIA) in the 2023 Annual Energy Outlook (AEO) in March 2023.

We summarize the avoided costs of natural gas for retail customers below (see Table 5). For both southern New England and northern New England, avoided natural gas costs are lower in AESC 2024 compared to AESC 2021 due to the reduction in gas commodity prices at the upstream supply points and at Henry Hub. Avoided gas costs, in real dollar terms, are also lower because the marginal gas transmission costs associated with the Dawn and Dracut supply resources are unchanged in nominal dollars. For Vermont (not shown in Table 5) avoided gas costs are also lower than in AESC 2021 because of lower local distribution company transmission costs, higher delivered cost of propane for the Vermont Gas System peaking facility, and lower long-term gas price trends at the Dawn hub.

Table 4. Summary of 15-year levelized Henry Hub, Algonquin Citygate, and basis differentials for AESC 2024 and AESC 2021

	Units	Henry Hub	Algonquin Citygates	Basis
AESC 2021 (2021–2035)	2024 $/MMBtu	$3.56	$4.74	$1.18
AESC 2024 (2024–2038)	2024 $/MMBtu	$3.48	$5.64	$2.16
Percent change	%	-2%	-19%	-

Schedule MM-R1

Table 5. Avoided cost of gas for all retail customers by end use assuming no avoidable margin

	Units	Southern New England	Northern New England
AESC 2021 (2021–2035)	2024 $/MMBtu	$7.32	$7.22
AESC 2024 (2024–2038)	2024 $/MMBtu	$6.39	$6.32
Percent change	%	-13%	-12%

Fuel oil and other fuels

In general, we find that avoided levelized costs for all fuels are moderately higher than AESC 2021 estimates. The primary factor driving avoided fuel oil costs and fuel oil prices is the price of crude oil, which is about 19 percent higher for the 20-year period from 2024 to 2043 in AESC 2024 than in AESC 2021. This is primarily due to much higher near-term prices; they are currently slightly higher than pre-pandemic levels. Because this is odd market behavior and probably not indicative of likely future prices, we follow the EIA Short Term Energy Outlook (STEO) for one year and then directly transition to the 2023 AEO forecast. Table 6 displays the levelized avoided fuel costs for AESC 2024.

The avoided costs for fuel oil products and other fuels by end use are based on market prices. Market prices provide an appropriate representation of the avoided costs because the supply systems for these fuels are flexible and diverse, and they are not subject to the capacity- or time-based constraints associated with electricity and natural gas.

Table 6. Avoided costs of retail fuels (15-year levelized, 2024 $ per MMBtu)

	Residential								Commercial		Transportation	
	No. 2 Distillate	Pro-pane	Keros-ene	B5 Biofuel	B20 Biofuel	B50 Biofuel	Cord Wood (Delivered)	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)	Motor Gasoline	Motor Diesel
AESC 2021 (2021–2035)	$27.14	$43.79	$33.41	$27.14	$24.42	-	$23.52	$25.36	$25.11	$17.77	$24.92	$25.70
AESC 2024 (2024–2038)	$30.60	$58.11	$38.47	$30.19	$25.58	$30.32	$29.37	$30.73	$28.59	$21.58	$27.16	$28.76
Change from AESC 2021 to AESC 2023	12.8%	32.7%	15.2%	11.2%	4.7%	-	24.9%	21.2%	13.8%	21.5%	9.0%	11.9%

Capacity

The avoided capacity costs in AESC 2024 are driven by actual and forecasted clearing prices in ISO New England's forward capacity market (FCM). The AESC 2024 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).

Schedule MM-R1

Importantly, AESC 2024 assumes a change in the capacity market structure beginning in 2028. Namely, this includes an assumption that ISO New England switches to a seasonal, prompt capacity market, with resource capacity accreditation based on each resource's marginal ability to avoid loss of load events during seasonal peak events.

Table 7 highlights the capacity prices projected in AESC 2024. Note that in 2028 and later years, capacity prices shown reflect a totaling of seasonal capacity prices, in years where both a winter and summer capacity price is present. Generally speaking, counterfactuals with lower seasonal peaks and more net firm capacity (i.e., higher reserve margins) have lower capacity prices than counterfactuals with higher seasonal peaks and less net firm capacity (i.e., lower reserve margins). 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 retirements of thermal generation, future changes in demand, and changes to capacity accreditation as more similar resources arrive on the system. Small year-on-year variations are due to changes in load, new resources coming online, and other resources retiring. In general, we find that capacity prices are generally similar to those projected in AESC 2021. Counterfactuals with higher peaks tend to have higher capacity prices than other counterfactuals, although this is impacted by the exogenous resource additions assumed for that scenario. AESC 2024's Counterfactual #1 features higher capacity prices than its AESC 2021 counterpart, in part due to a deferral of clean energy resources (compared to the assumptions used in AESC 2021).

Counterfactuals that are missing programmatic demand response resources or programmatic BTM storage (i.e., Counterfactuals #1, #4 and #6) have less exogenous firm capacity. Therefore, they have lower near-term reserve margins, and higher near-term capacity prices, compared to counterfactuals with the same respective load components. Eventually, these higher capacity prices lead to incremental endogenous gas and battery storage additions in the mid 2030s, beyond what gets added in the equivalent load counterfactuals with the exogenous firm capacity present. Each single gas plant that gets added provides a large amount of firm capacity, and results in larger reserve margins than might be observed if gas plants were not large, discrete resources. This capacity overbuild that occurs in the mid-2030s drives down longer-term capacity market prices towards the end of the study period for these counterfactuals.

Schedule MM-R1

Table 7. Comparison of capacity prices in rest-of-pool (2024 $ per kW-month)

Commitment Period (June to May)	FCA	Actual	Actual but for post-2023 EE	AESC 2024 CF #1	CF #2	CF #3	CF #4	CF #5	CF #6	AESC 2021 CF #1
2024/2025	15	$2.61	$2.66	$2.66	$2.61	$2.66	$2.61	$2.61	$2.61	$3.10
2025/2026	16	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$3.07
2026/2027	17	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$3.25
2027/2028	18			$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$3.51
2028/2029	19			$2.57	$1.42	$1.42	$2.83	$1.42	$4.25	$3.72
2029/2030	20			$2.83	$1.42	$2.83	$4.25	$2.83	$5.66	$4.06
2030/2031	21			$4.25	$1.42	$2.83	$4.25	$2.83	$5.66	$3.86
2031/2032	22			$4.25	$1.42	$2.83	$4.25	$1.42	$5.66	$4.15
2032/2033	23			$5.66	$2.83	$5.66	$5.66	$4.25	$7.08	$4.40
2033/2034	24			$5.66	$2.83	$4.25	$5.66	$2.83	$5.66	$4.36
2034/2035	25			$7.08	$5.66	$5.66	$8.49	$7.08	$4.25	$5.27
2035/2036	26			$5.66	$5.66	$2.83	$7.08	$8.49	$7.08	$4.13
2036/2037	27			$4.25	$4.25	$1.42	$4.25	$7.08	$4.25	n/a
2037/2038	28			$7.08	$5.66	$5.66	$7.08	$7.08	$5.66	n/a
2038/2039	29			$7.08	$7.08	$4.25	$7.08	$7.08	$8.49	n/a
2039/2040	30			$5.66	$5.66	$5.66	$5.66	$7.08	$5.66	n/a
2040/2041	31			$10.53	$5.66	$5.66	$5.66	$9.51	$4.25	n/a
2041/2042	32			$7.08	$5.66	$5.66	$4.25	$8.49	$5.66	n/a
2042/2043	33			$5.66	$4.25	$7.08	$2.83	$9.51	$4.25	n/a
2043/2044	34			$7.08	$5.66	$7.08	$2.83	$9.51	$4.25	n/a
2044/2045	35			$7.08	$5.66	$7.08	$2.83	$9.51	$2.83	n/a
2045/2046	36			$9.51	$7.08	$5.66	$2.83	$8.49	$4.25	n/a
2046/2047	37			$9.51	$8.49	$7.08	$2.83	$7.08	$2.83	n/a
2047/2048	38			$11.94	$8.49	$5.66	$2.83	$5.66	$2.83	n/a
2048/2049	39			$8.49	$8.49	$7.08	$2.83	$7.08	$2.83	n/a
2049/2050	40			$8.49	$5.66	$7.08	$4.25	$9.51	$2.83	n/a
2050/2051	41			$7.08	$5.66	$5.66	$2.83	$7.08	$2.83	n/a
15-year levelized cost				**$4.73**	**$3.60**	**$3.66**	**$5.02**	**$4.51**	**$5.23**	**$3.96**
Percent difference				**19%**	**-9%**	**-8%**	**27%**	**14%**	**32%**	**-**

Notes: Levelization periods are 2024/2025 to 2038/2039 for AESC 2024 and 2021/2022 to 2035/2036 for AESC 2021. Real discount rate is 1.74 percent for AESC 2024 and 0.81 percent for AESC 2021. 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 2024 User Interface. Future costs for Counterfactual (CF) #1 are summer capacity prices, for the months of June through September. Capacity prices for 2028–2050 are weighted four months for summer prices and eight months for winter prices.

Energy

On a levelized basis, the 15-year AESC 2024 annual all-hours price for Counterfactual #1 is $50 per MWh, compared to the equivalent value of $46 per MWh from AESC 2021. This represents a price increase of 9 percent. Relative to Counterfactual #1, counterfactuals and years with higher loads and peaks tend to have higher energy prices, while counterfactuals with lower loads and peaks tend to have lower energy prices. The increase in energy prices observed in AESC 2024 is primarily due to higher near-term wholesale gas prices and a deferral of zero-marginal-cost clean energy to later in the study period, relative to AESC 2021.

Schedule MM-R1

Table 8 shows levelized costs (over 15 years) for Massachusetts. The table shows prices 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 2024 study are 9 percent higher than the prices modeled in the 2021 AESC study. Key drivers of these lower prices include higher Henry Hub natural gas prices and a deferral of low- or zero-variable operating cost renewables (relative to the assumptions used in AESC 2021).

Table 9 compares 15-year levelized costs between AESC 2024 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.

Table 8. Comparison of energy prices for Massachusetts (2024 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	$46.11	$52.90	$51.02	$36.88	$33.71
AESC 2024 Counterfactual 1	$50.36	$61.22	$57.34	$57.34	$33.55
AESC 2024 Counterfactual 2	$47.42	$57.41	$53.44	$53.44	$32.27
AESC 2024 Counterfactual 3	$50.92	$62.27	$58.79	$58.79	$31.53
AESC 2024 Counterfactual 4	$50.30	$61.42	$58.20	$58.20	$30.94
AESC 2024 Counterfactual 5	$50.38	$61.64	$58.06	$58.06	$31.12
AESC 2024 Counterfactual 6	$49.70	$60.75	$57.56	$57.56	$30.46
% Change: Counterfactual 1	9%	16%	12%	55%	0%
% Change: Counterfactual 2	3%	9%	5%	45%	-4%
% Change: Counterfactual 3	10%	18%	15%	59%	-6%
% Change: Counterfactual 4	9%	16%	14%	58%	-8%
% Change: Counterfactual 5	9%	17%	14%	57%	-8%
% Change: Counterfactual 6	8%	15%	13%	56%	-10%

Notes: All prices have been converted to 2024 $ per MWh. Levelization periods are 2021–2035 for AESC 2021 and 2024–2038 for AESC 2024. The real discount rate is 0.81 percent for AESC 2021 and 1.74 percent for AESC 2024. AESC 2021 values are from the AESC 2021 User Interface, while AESC 2024 values are from the AESC 2024 User Interface.

Schedule MM-R1

Table 9. Avoided energy and RPS compliance costs with risk premium, AESC 2024 vs. AESC 2021 (15-year levelized costs, 2024 $ per kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2024 Counterfactual 1	1	Connecticut	$0.083	$0.079	$0.079	$0.053
	2	Massachusetts	$0.090	$0.086	$0.086	$0.061
	3	Maine	$0.082	$0.078	$0.078	$0.052
	4	New Hampshire	$0.078	$0.074	$0.074	$0.048
	5	Rhode Island	$0.088	$0.084	$0.084	$0.059
	6	Vermont	$0.075	$0.070	$0.070	$0.044
AESC 2021 Counterfactual 1	1	Connecticut	$0.061	$0.060	$0.045	$0.042
	2	Massachusetts	$0.065	$0.063	$0.049	$0.046
	3	Maine	$0.060	$0.058	$0.044	$0.041
	4	New Hampshire	$0.061	$0.059	$0.045	$0.042
	5	Rhode Island	$0.068	$0.066	$0.052	$0.049
	6	Vermont	$0.057	$0.055	$0.041	$0.038
Delta	1	Connecticut	$0.022	$0.020	$0.034	$0.011
	2	Massachusetts	$0.026	$0.023	$0.037	$0.015
	3	Maine	$0.023	$0.020	$0.034	$0.011
	4	New Hampshire	$0.017	$0.015	$0.029	$0.006
	5	Rhode Island	$0.020	$0.018	$0.032	$0.009
	6	Vermont	$0.018	$0.015	$0.030	$0.006
Percent Difference	1	Connecticut	35%	33%	77%	27%
	2	Massachusetts	40%	36%	76%	32%
	3	Maine	38%	34%	77%	27%
	4	New Hampshire	28%	25%	64%	14%
	5	Rhode Island	30%	26%	60%	19%
	6	Vermont	31%	27%	73%	17%

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 2024 dollars per kWh. Levelization periods are 2021–2035 for AESC 2021 and 2024–2038 for AESC 2024. The real discount rate is 0.81 percent for AESC 2021 and 1.74 percent for AESC 2024. Values do not include losses.

RPS compliance

Reduction in load due to energy efficiency or other demand-side resources will reduce total load-serving entity (LSE) load and thus reduce the RPS obligations of LSEs and the associated compliance costs recovered from consumers. Conversely, increases in load tend to increase RPS obligations of LSEs, increasing the associated compliance costs recovered from consumers. The avoided cost of RPS compliance is a function of renewable energy certificate prices and RPS target percentage.

Relative to AESC 2021, AESC 2024 sees higher prices for meeting RPS compliance (see Table 10). This difference is attributable to near-term shortages and cost increases for materials and labor, delays in offshore wind deployment and regional transmission expansion, and increases in the long-term cost of entry due to the lasting effects of the war in Ukraine and the COVID-19 pandemic. The cost of RPS compliance is also impacted by increased RPS stringencies in multiple states and the addition of new RPS categories such as Maine Class I Thermal, Massachusetts Clean Peak Standard (CPS), and the Massachusetts Greenhouse Gas Emissions Standard (GGES) for municipal light plants. On a 15-year

Schedule MM-R1

levelized basis, costs of RPS compliance tend to be similar across counterfactuals as most counterfactuals typically feature similar renewable builds through the mid-2030s as a result of assumed renewable procurements.

Table 10. Avoided cost of RPS compliance (2024 $ per MWh)

	CT	ME	MA	NH	RI	VT
AESC 2021	$10	$9	$14	$10	$18	$5
AESC 2024 Counterfactual 1	$17	$16	$25	$12	$23	$8
AESC 2024 Counterfactual 2	$17	$16	$25	$12	$23	$8
AESC 2024 Counterfactual 3	$18	$17	$26	$12	$24	$8
AESC 2024 Counterfactual 4	$17	$16	$24	$12	$22	$8
AESC 2024 Counterfactual 5	$17	$16	$25	$12	$23	$8
AESC 2024 Counterfactual 6	$17	$16	$25	$12	$22	$8
Pcnt Change: Counterfactual 1	79%	83%	71%	21%	25%	67%
Pcnt Change: Counterfactual 2	79%	83%	71%	21%	25%	67%
Pcnt Change: Counterfactual 3	92%	91%	79%	24%	32%	70%
Pcnt Change: Counterfactual 4	77%	80%	70%	21%	22%	66%
Pcnt Change: Counterfactual 5	78%	82%	71%	21%	24%	66%
Pcnt Change: Counterfactual 6	79%	81%	74%	21%	23%	66%

Non-embedded environmental compliance

AESC 2024 provides several approaches to enable individual states to address specific policy directives regarding greenhouse gas (GHG) impacts. Table 11 and Table 12 compare these costs.

- A "damage cost" approximated by the social cost of carbon (SCC). An SCC should apply low discount rates, consider global damages, and consider high-impact events. The Synapse Team recommends the set of SCC values published by U.S. Environmental Protection Agency (EPA) in November 2022. We recommend a 15-year levelized SCC in the range of $249 to $415 per short ton of carbon dioxide (CO_2) in AESC 2024, with this range reflecting a choice between a 2.0 percent for the lower cost and a 1.5 percent discount rate for the higher cost. This range reflects the range of discount rates within EPA's recommendation, including the latest recommendations from U.S. Office of Management and Budget (OMB) and the majority of discount rate recommendations in the literature, as cited by U.S. EPA. New to AESC 2024, we are also recommending the inclusion of analogous social costs of two other greenhouse gases: methane (CH_4) and nitrous oxide (N_2O).
- An approach based on marginal abatement costs, assuming a cost derived from electric sector technologies. Marginal abatement costs assert 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. Offshore wind is the most appropriate marginal abatement technology for New England under the assumption 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 2024, we estimate a total environmental cost based on a projection of future cost trajectories for offshore wind energy along the eastern seaboard of $185 per short ton of CO_2-eq emissions. This differs from the AESC 2021 price largely related to an adjusted projection of the cost of this technology.

Schedule MM-R1

- An approach based on New England marginal abatement costs of $581 per short ton of CO_2-eq emissions, assuming a cost derived from multiple sectors. 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) and seek to develop a complete list of comparatively politically feasible technologies that would lead to decarbonization, or in other cases where electrification is not being considered a viable technology (e.g., under one of the counterfactuals). In AESC 2024, this approach is based on a projection of future cost trajectories for renewable natural gas (RNG). This value can be compared to a value of $557 per short ton (in 2024 dollars) from AESC 2021. This projected value in AESC 2024 is lower due to (a) different considerations of RNG feedstock and (b) updated information on costs and potentials of RNG feedstock.

Table 11. Comparison of GHG costs under different approaches (2024 $ per short ton) in Counterfactual #1

	AESC 2021	AESC 2024	Difference	% Difference
Social cost of greenhouse gases (SC-GHG or "damage cost") at 1.5% and 2% discount rates	$144 (2% only)	$249 to 415	$104 to 270	72 to 187%
New England-based marginal abatement cost, derived from the electric sector	$141	$173	$32	23%
New England-based marginal abatement cost, derived from multiple sectors	$557	$581	$24	4%

Notes: All values shown are levelized over 15 years. All AESC 2024 values except the SCC are levelized using a 1.74 percent discount rate (the 2.0 percent SCC is levelized using a 2.0 percent discount rate, while the 1.5 percent SCC is levelized using a 1.5 percent discount rate). All AESC 2021 values are levelized using a 0.81 percent discount rate, except SCC which uses a 2 percent discount rate, then converted into 2024 dollars. Values shown above remove energy prices, but not embedded costs. Values shown above do not include transmission and distribution losses.

Table 12. Comparison of GHG costs under different approaches (2024 cents per kWh) in Counterfactual #1

	AESC 2021	AESC 2024	Difference	% Difference
Social cost of greenhouse gases (SC-GHG or "damage cost") at 1.5% and 2% discount rates	5.50 (2% only)	8.95 to 15.37	3.45 to 9.88	63 to 180%
New England-based marginal abatement cost, derived from the electric sector	5.35	6.47	1.11	21%
New England-based marginal abatement cost, derived from multiple sectors	22.25	21.71	-0.56	-2%

Notes: Values shown above remove embedded costs (e.g., RGGI, MA 310 7.74, MA 310 7.75). All values quoted use a summer on-peak seasonal marginal emission rate and include a 9 percent energy loss factor. All values shown are only inclusive of point-of-consumption CO2 GHGs and do not include upstream GHGs or GHG cost impacts related to CH4 or N2O.

DRIPE

Demand reduction induced price effect (DRIPE) refers to the reduction in prices in the wholesale markets for capacity and energy 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 reduction in wholesale prices seen by all retail customers in a given period. AESC 2024 models DRIPE benefits associated with reduced demand on electricity (energy and capacity), natural gas (supply and transportation), and oil markets. Generally,

Schedule MM-R1

DRIPE is first calculated with a "price shift" that represents the change in price for a change in demand. The price shift is then adjusted so that it may be applied to any generic change in demand and represent the market in question.

Generally speaking, compared to AESC 2021, we find (a) similar energy DRIPE values due to a number of factors (including changes in energy prices, changes in load, and changes in hedging assumptions) that largely offset one another, (b) generally similar trends in capacity DRIPE values, with values that are highly variable year-to-year in both AESC 2024 and AESC 2021, especially in the near-term years due to market price separation, (c) lower gas supply and electric-to-gas DRIPE values due to decreases in price shifts, (d) higher gas-to-electric cross-DRIPE values due to increases in price shifts, and (e) higher oil DRIPE values, due to changes in the underlying projection of crude oil prices.

Transmission and distribution

Measures that reduce peak loads can contribute to deferring or avoiding the T&D investments required to continue serving growing loads, such as building new transmission facilities or upgrading existing lines. There are three main types of avoided T&D: regional transmission (i.e. regional pooled facilities (PTF)), local transmission, and local distribution.

In AESC 2024, we estimate an avoided pool transmission facility cost of $69 per kW-year. This can be thought of as the cost of deferring the PTF investment by one year as a result of a one-year reduction in peak load. This value is lower than the $95 per kW-year (in 2024 dollars) estimated in AESC 2021; in AESC 2024 we based the avoided cost on a recent ISO New England Transmission Study. This study estimates the future transmission investments through 2050 that are required to enable a smooth and reliable energy transition.

AESC provides a discussion of the utility practices and methods used to calculate local T&D. In a previous AESC, the Synapse Team surveyed some of the sponsoring utilities on their avoided local T&D estimates and developed a common evaluation rubric for AESC 2021. As with AESC 2021, AESC 2024 presents the following:

1. Reviewing utility approaches to generic avoided cost values for non-pool transmission facilities T&D and evaluating these approaches on a common evaluation rubric to facilitate cross-comparison and learning.
2. Reviewing utility approaches to calculating geographically localized avoided costs, such as for non-wire alternatives (NWA).

Reliability

As in previous AESC reports, AESC 2024 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 reliability associated with reduced load levels on T&D, and value of lost load (VoLL). We also estimate the value of increased generation reliability per kilowatt of peak load reduction.

Schedule MM-R1

In AESC 2024, we find a default average VoLL of $61 per kWh. This value is about 26 percent less than the value derived in AESC 2021 ($82 per kWh in 2024 dollars), as a result of specifying the value to the New England states. 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 linking to improving generation reliability. In AESC 2024, we find 15-year levelized values of $0.38 per kW-year for cleared benefits and $4.82 per kW-year for uncleared benefits. These are 25 to 50 percent lower than the same values estimated in AESC 2021, after adjusting for inflation. The primary differences for these changes include a reduction in the assumed VoLL (as described above) and different input parameters related to the capacity market supply and demand curves.

Sensitivities

In AESC 2024, we evaluate avoided costs under two different sensitivities. These sensitivities include:

- A natural gas price sensitivity with higher gas prices than were used in Counterfactual #1 ("High Gas Price Sensitivity"). In this sensitivity, the Henry Hub gas price depicts a future with higher gas prices as a result of lower gas recovered per well and lower assumed rates of technological improvement. This high gas price forecast is best used for examining likely avoided costs in a future where the long-term fundamentals behind natural gas prices are different than in the main counterfactuals, and where the grid is allowed to respond and build different resources accordingly.
- A sensitivity which models a future with many distributed energy resources (DER) and increased levels of non-emitting electricity ("Increased Clean Electricity Sensitivity"). This sensitivity models a clean electricity goal of 90 percent regionwide by 2035 as a hypothetical Increased Regional Clean Electricity Policy (IRCEP) that functions like a new, additional RPS policy covering New England.

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

- In the High Gas Price Sensitivity, energy prices are 21 percent higher, capacity prices are 6 percent higher, RPS compliance costs are 3 to 10 percent lower, and non-embedded GHG costs are the same for jurisdictions that use the social cost of carbon and lower for jurisdictions that use the marginal abatement cost (because part of the construction of this value is the energy price). All prices are compared to Counterfactual #1.[3]

- In the Increased Clean Electricity Sensitivity, energy prices are 11 percent lower, capacity prices are 32 percent lower, RPS compliance costs inclusive of the hypothetical IRCEP policy unchanged, and non-embedded GHG costs are unchanged. All prices are compared to Counterfactual #5.

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 unchanged in jurisdictions

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

Schedule MM-R1

that utilize a social cost of carbon, but is lower in jurisdictions that utilize a marginal abatement cost because one of the inputs to this value is the energy price. Generally speaking, higher energy prices will produce lower non-embedded GHG costs. For a similar reason, RPS compliance costs are lower, as renewables participating in the RPS policies are able to cover more of their costs through energy market revenues. Finally, capacity prices are similar, as a result of overall similar requirements to meet peak demand.

In the Increased Clean Electricity Sensitivity, near-term energy prices are similar to Counterfactual #5. Energy prices diverge from those in Counterfactual #5 in the early 2030s when additional renewable resources come online. The increase in renewable resources reduces energy prices because they have zero-marginal operating costs. Capacity prices in the Clean Electricity Sensitivity are identical or similar to prices in Counterfactual #5 from FCA 15 through FCA 22. Beginning in FCA 23, the Clean Electricity Sensitivity features a decrease in capacity prices due to higher levels of exogenous renewable energy being deployed by the IRCEP program. The additional exogenous renewable energy provides extra firm capacity, which leads to larger reserve margins and shifts in the capacity market supply curve to the right. As a result, the capacity market clears at a lower price.

Schedule MM-R1

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 natural gas sold to LDCs, electricity generators, and other large end users at interstate pipeline delivery points. The discussion then addresses the factors that drive the price 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, we present natural gas avoided costs with and without the retail margin.

In the near term, natural gas prices in AESC 2024 are higher than in AESC 2021, as a result of evolving dynamics related to worldwide natural gas demand. In the long run, the AESC 2024 prices from 2030 to 2050 drop to an average of $3.71 per MMBtu, which is close to the long-run average in AESC 2021. We note that gas prices are data available at the time of this study, including near-term NYMEX data published in Fall 2023 and mid- and long-term price projections published by the EIA in its Annual Energy Outlook (AEO) 2023 report.

For the purposes of AESC 2024, we assume a single counterfactual future: one where gas consumption resembles the forecast projected in AEO 2023 and does not consider any future energy efficiency or electrification measures. This is consistent with the approach used in AESC 2021 and other prior AESC studies.

2.1. Introduction

The year 2022 saw the highest annual average Henry Hub price since 2008. The elevated prices were driven by restricted supply due to economic conditions, weather-related declines in U.S. gas production, and increased weather-driven demand in the United States (for heating in the winter and electric generation in the summer) along with increased LNG exports to Europe.[4] Henry Hub spot prices first began to rise in the middle of 2021. This trend continued throughout 2022: prices were above $4 per MMBtu throughout the year and peaked in August 2022—reaching $9.85 per MMBtu on August 22, 2022.

The elevated Henry Hub prices are reflected in the latest AEO, published by the EIA in March 2023.[5] The report projects a gradual return to long-run average prices, and in real terms, the Henry Hub spot price

[4] U.S. EIA. 2023. "Average cost of wholesale U.S. natural gas in 2022 highest since 2008." *Today in Energy.* Available at: https://www.eia.gov/todayinenergy/detail.php?id=55119.

[5] U.S. EIA. 2023. *Annual Energy Outlook (AEO) 2023*. Available at: https://www.eia.gov/outlooks/aeo/.

Schedule MM-R1

averages $3.71 per MMBtu from 2030–2050. These are not substantially different than AEO 2021's 2030–2050 average of $3.52 per MMBtu.

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

Beginning around 2007, monthly shale gas production started a period of significant growth that continues to this day. In 2000 the United States produced 19.1 trillion cubic feet (tcf) of natural gas, which was less than the 23.3 tcf of natural gas consumed. Starting in 2017 production outpaced consumption. In 2022, the United States produced 35.8 tcf to supply 32.3 tcf consumption and 3.9 tcf of exports.[6]

In the three years since the AESC 2021 analysis, the supply growth trends have continued as production continued to increase, with supply mainly from the Marcellus and Utica (Pennsylvania, West Virginia, and Ohio), Permian (Texas and New Mexico), and Haynesville (Louisiana and Texas). However, the growth in domestic consumption has moderated, and recently has been flat. Recent news has also focused on the increase of LNG exports, which are primarily from new terminals on the Gulf Coast and Eastern Seaboard.

The upstream (production) side has seen a geographical shift. Since the beginning of 2018, Permian gas production has more than tripled, compared to a 40 percent increase in Marcellus volumes.

Over the past two years, the New England gas market has seen stable demand (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.

[6] U.S. EIA. 2023. "Natural Gas Explained: where our natural gas comes from". Available at: https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php.

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.

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.[7] 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). Export capacity has increased from roughly 3 billion cubic feet per day (Bcfd) from the end of 2017 to a projected 12 Bcfd in 2023.[8] Nearly 10 percent of U.S. gas demand now comes from LNG exports, with the bulk of that along the Gulf Coast. Even more LNG export capacity is expected to go online in 2024: Golden Pass in Texas and Plaquemines in Louisiana. 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.

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[7] 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 2024 Study in August 2023.

[8] U.S. EIA. “STEO Between the Lines: U.S. LNG Exports will increase next year as two export terminals come online.” *Short-Term Energy Outlook*. Available at: https://www.eia.gov/outlooks/steo/report/BTL/2023/07-LNG/article.php#:~:text=We%20expect%20U.S.%20LNG%20exports,increase%20to%2013.3%20Bcf%2Fd.

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 2024–2025 NYMEX futures complex to develop long-term monthly trends for the Henry Hub gas price over the 2024–2050 study period.

As with previous AESC studies, we rely on AEO for longer-term Henry Hub price forecasts. The most recent current AEO was published in March 2023 (AEO 2023).[9] 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. 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 2023's Reference Case incorporates provisions from the *Inflation Reduction Act of 2022* (IRA) that would influence energy consumption, production, and trade.[10]

The changes in the Reference case in AEO 2023 are driven by the impacts of the IRA, updated technology costs and performance, and changes in macroeconomic outlook. It also shows a "significant shift towards lower future emissions," driven by increased electrification, equipment efficiency, and renewable technologies for energy generation.[11] On average, the Henry Hub price forecast for the AEO 2023 reference case is approximately 5 percent higher than the corresponding forecast from AEO 2021. Meanwhile, alternative scenarios explored in AEO 2023 ("side cases") consider the impacts of high and low oil and gas supply, high and low zero-carbon technology, and different macroeconomic cases.

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[9] U.S. EIA. 2023. *Annual Energy Outlook (AEO) 2023*. Available at: https://www.eia.gov/outlooks/aeo/.

[10] Assumptions are documented in several reports. See EIA's AEO discussion at https://www.eia.gov/outlooks/aeo/narrative/index.php#Appendix.

[11] U.S. EIA. 2023. "Executive Summary". *Annual Energy Outlook (AEO) 2023*. Available at: https://www.eia.gov/outlooks/aeo/.

Schedule MM-R1

For AESC 2024, we use the current NYMEX Henry Hub futures forecast for short-term prices (through 2025) and AEO 2023 for medium- and long-term prices. We believe that the NYMEX Henry Hub price forecast incorporates an independent and collective view of the market supply and demand balances. Meanwhile, AEO 2023 represents a neutral, third-party projection of Henry Hub prices based on recent trends and expectations.

The following section provides highlights of the AEO 2023 Reference case and other AEO cases.

AEO 2023 Reference case

Compared to the recent past, the AEO 2023 Reference case projects U.S. natural gas industry growth driven by electric generation requirements and LNG exports. Gas production in the United States (dry gas) is projected to remain at historically high levels, supported by stable domestic natural gas consumption and high international demand for LNG. The United States is projected to remain a net exporter of natural gas through 2050 in all the AEO 2023 cases.

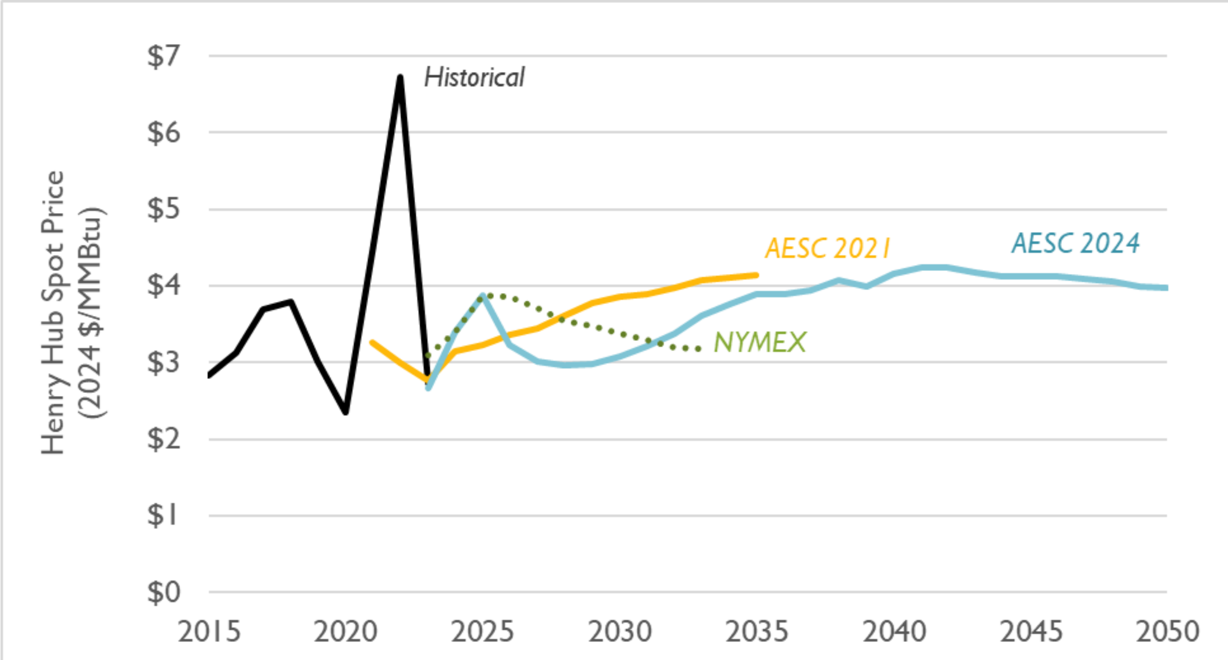
In AEO 2023, real Henry Hub prices (in 2022 dollars) are projected to fall steadily from $6.52 per MMBtu in 2022 to $3.49 per MMBtu in 2025. Prices then stabilize, averaging $3.71 per MMBtu over the period from 2030 to 2050.

Figure 2 shows the forecast of Henry Hub prices used in AESC 2024. These rely on NYMEX futures (from August 2023) for prices between September 2023 and December 2025.[12] Prices in 2026 through 2050 are based on AEO 2023.

[12] Historical Henry Hub prices were retrieved from Natural Gas Intelligence's (NGI's) "Daily" subscription service. NYMEX Futures prices for Henry Hub were retrieved from NGI's "Forward Look" subscription service. More details on each service can be found at: https://www.naturalgasintel.com/.

Schedule MM-R1

Figure 2. Henry Hub price forecasts (Actuals, NYMEX, AESC 2024, and AESC 2021)



As shown in Figure 2, Henry Hub natural gas prices in AESC 2024 eventually stabilize at a value close to AESC 2021. Despite the short-term price spike, forecasts of Henry Hub prices have continually declined over the past decade for several reasons.

1. Productivity in shale drilling has been increasing steadily. Per EIA, average productivity (new well gas production per rig) 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 January 2021 report,[13] and 5,264 Mcf in the September 2023 report. This continues the observed trend from the previous decade, that costs per unit of production have decreased, although AEO assumes 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, which places upward pressure on gas prices.

LNG exports from the United States have grown since 2016, increasing such that the United States became the world's largest LNG exporter in 2022. Growth in LNG exports is caused by increased LNG export capacity, higher international prices for natural gas and LNG, and increased demand, particularly

[13] U.S. EIA. 2021. 2019. "Drilling Productivity Report." *Petroleum and Other Liquids*. Available at: https://www.eia.gov/petroleum/drilling/.

from Europe.[14] The AEO 2023 Reference Case projects that total natural gas exports, pipeline gas. and LNG will become the largest component of demand by the early 2030s.[15] Scenario modeling by the EIA show that higher LNG exports drive U.S. natural gas prices higher, driven by the sensitivity of demand from the electric power sector and, to a lesser extent, the manufacturing sector.[16]

Extreme weather events drive natural gas prices higher. Extreme cold increases heating demand as residential and commercial customers crank up their natural gas furnaces and boilers. Extreme heat also has an impact, as the demand for cooling increases demand for electricity supplied by natural-gas-fired generating facilities.

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 PipeLines (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 Constellation Energy's Everett terminal. There is also the Saint John 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 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

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[14] U.S. EIA. 2022. "The United States Became the World's largest LNG exporter in the first half of 2022." *Today in Energy*. Available at: https://www.eia.gov/todayinenergy/detail.php?id=53159.

[15] U.S. EIA. 2023. *AEO 2023 Issues in Focus: Effects of Liquefied Natural Gas exports on U.S. Natural Gas Market*. Page 3.

[16] Id. page 4.

are notionally purchasing gas from distant supply basins (Gulf Coast, Western Canada, Permian Basin, etc.).[17] 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 (ICE) and there is a market up to 48 months out. AGT spot prices are also quoted in several publications and on the EIA website; we retrieved them from Natural Gas Intelligence (NGI) in this analysis. For 2026 and later years, to calculate the future monthly variation in prices for Henry Hub, Algonquin Citygate, and other hubs upstream of New England, we average historical and projected monthly data (based on NYMEX) for the period 2021–2025.[18] For Henry Hub, we apply the "shape" of this monthly variation to the annual data from AEO 2023. 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 from NGI, allowing us to apply the seasonality in monthly prices to our longer-term projections. See Figure 3 for a historical comparison of gas prices at Algonquin Citygate and Henry Hub. For purposes of electricity modeling, the relationship of daily Algonquin Citygate pricing is analyzed relative to heating degree days (HDDs), with a relationship between daily price deviations from a monthly average relative to HDDs being derived. We then applied these daily price changes to the weather data inherent in the 2002 electricity load shape to modify the projection of monthly prices on a daily basis (for more on this 2002 load shape, see Section 4.3: *New England system demand and energy components*).

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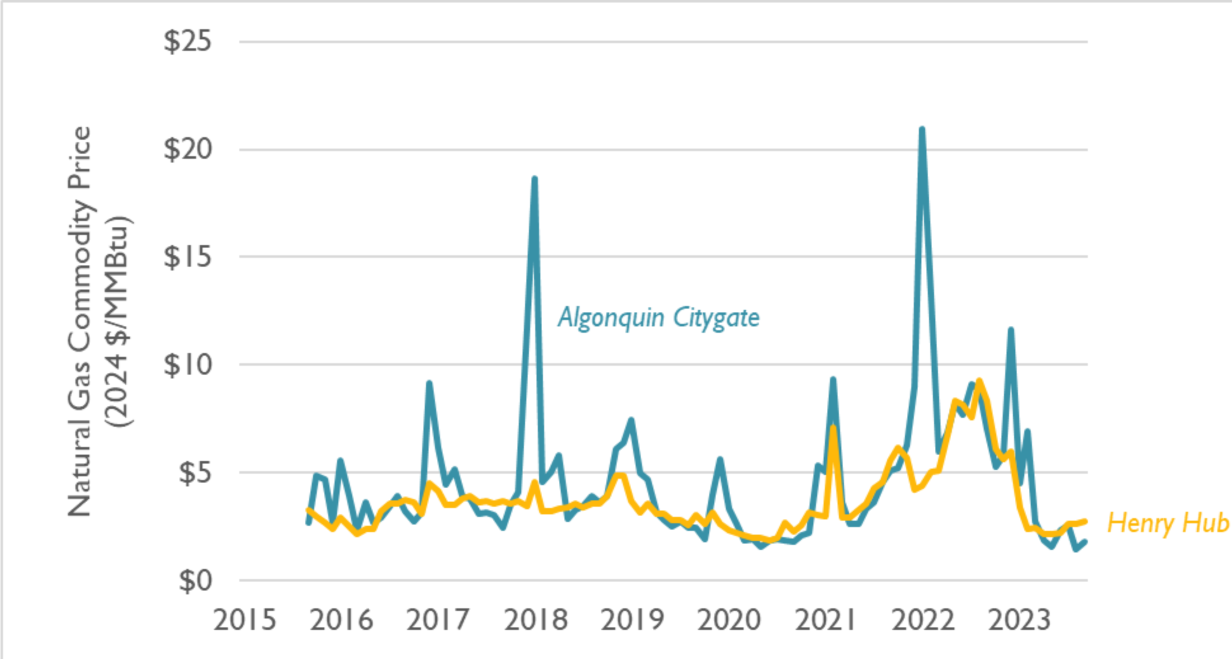
[17] Since natural gas is fungible, interstate pipelines can displace gas anywhere it enters or leaves the system.

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

Schedule MM-R1

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



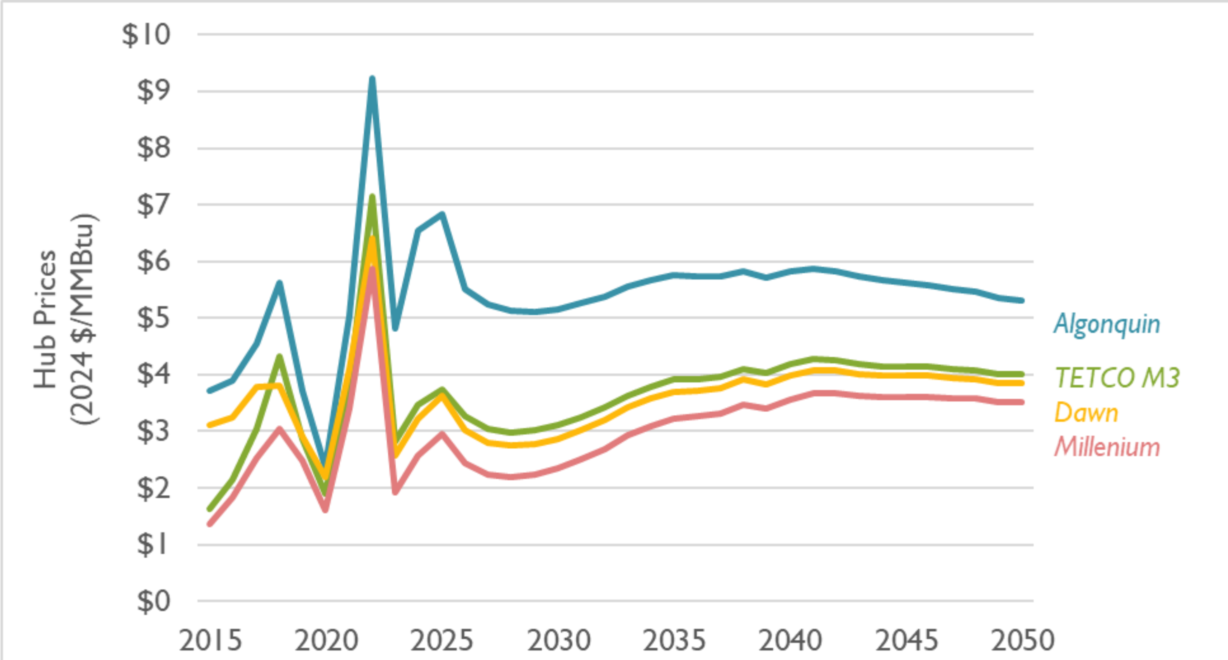
In AESC 2024, we use the Millenium East Pool price, which is more representative of the actual prices paid by New England LDCs for gas transported through recently acquired pipeline capacity.[19] To cover the major gas supply sources, we model monthly prices at the Dawn Ontario Hub, Millennium Pool, and TETCO M3 Hub using a similar methodology as our projection for the Algonquin Citygate basis (see Figure 4). We assume the projected monthly basis values for these hubs 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 Henry Hub, and NGI publishes prices for Millennium and the Dawn Hub. In most cases there is both a spot and a futures market of varying lengths at these hubs. 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.

[19] 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. In AESC 2021, we used Texas Eastern Zone M-2 (TETCO M2).

Schedule MM-R1

Figure 4. Historical and projected prices for various hubs



2.3. New England natural gas market

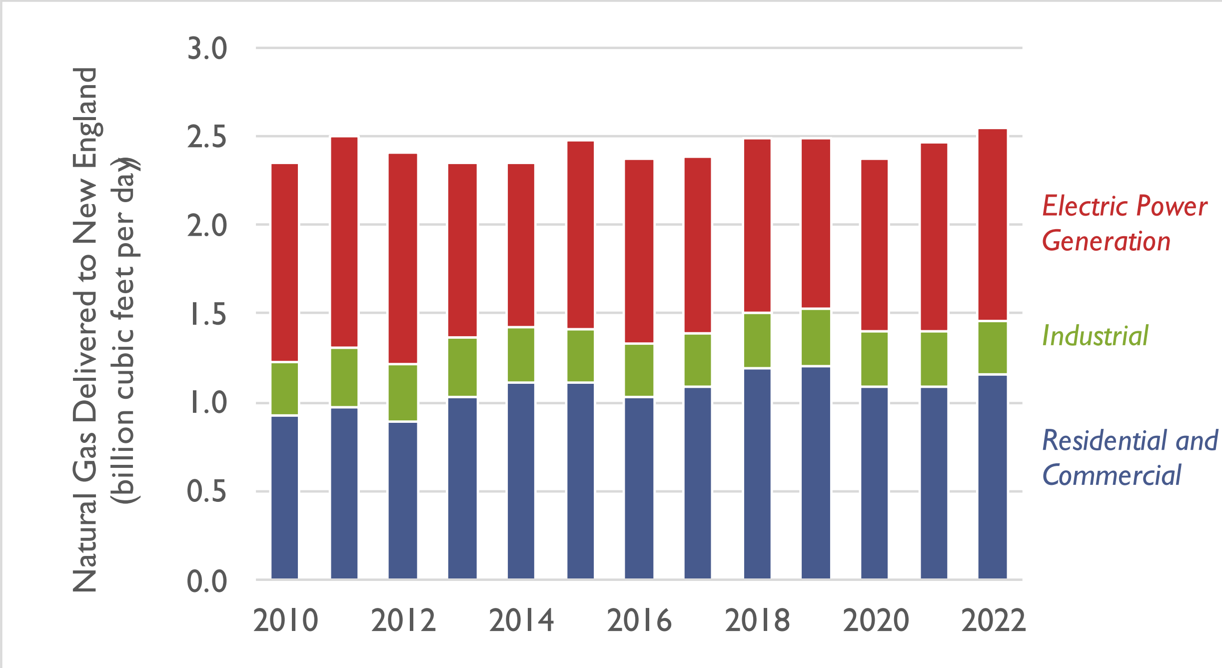
In addition to the commodity costs discussed above, natural gas avoided costs include the costs of transmission, storage, and peaking resources needed to make gas available where and when it is consumed. This section addresses the gas supply resource costs that would be avoided by reducing gas use and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

Natural gas consumption

Figure 5 shows the natural gas delivered to end users in the six New England states for the years 2010 through 2022. Growth in residential and commercial consumption has been largely offset by lower gas use for electricity generation.

Schedule MM-R1

Figure 5. Historical natural gas deliveries in New England

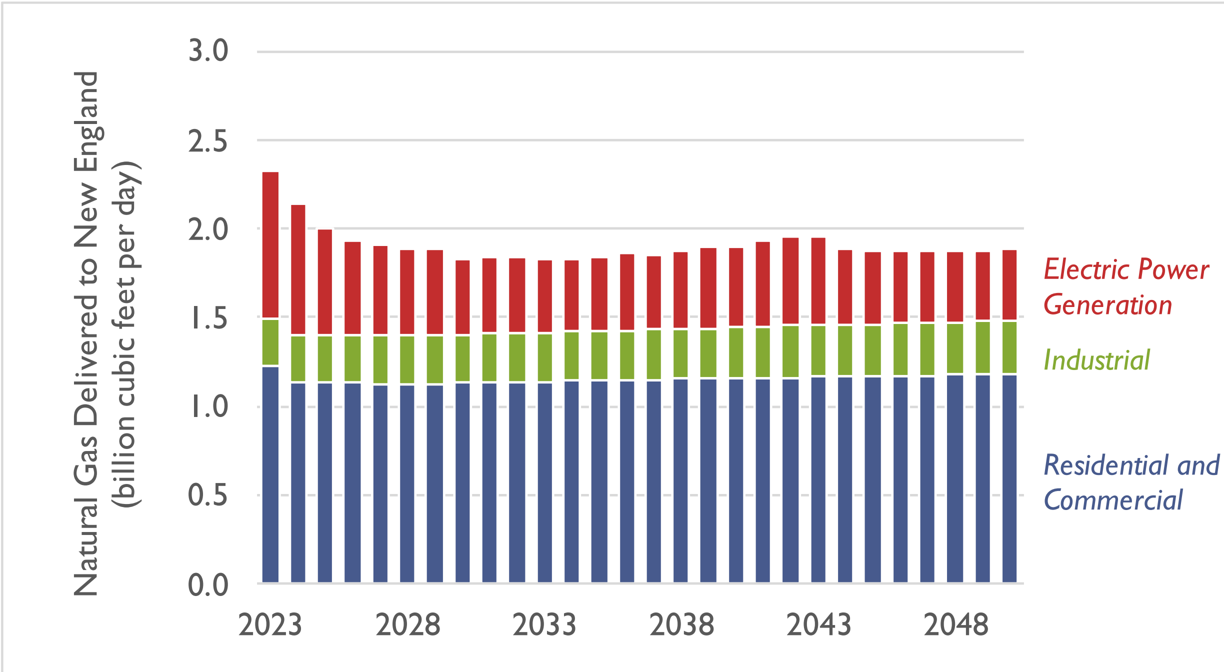


Source: U.S. Energy Information Administration (EIA). Available at *https://www.eia.gov/dnav/ng/ng_cons_sum_a_EPG0_vgt_mmcf_a.htm. Note that values have not been normalized for variations in weather.*

As a point of reference, the AEO 2023 Reference case forecast for New England shows a gradual increase in non-electric consumption of natural gas through 2050 (see Figure 6). Meanwhile, EIA's AEO projects gas consumption in the electric power sector to be halved by 2026, then remain at a relatively consistent level through 2050. Please note we do not use AEO's forecasts for gas consumption in AESC 2024; instead we calculate projections of gas consumption in the electric sector dynamically in the EnCompass model (see Chapter 4: *Common Electric Assumptions* and Chapter 5: *Avoided Capacity Costs* for more) while we base consumption in the non-electric sectors on data from the LDCs (see subsequent text in this chapter).

Schedule MM-R1

Figure 6. AEO 2023 natural gas consumption forecast for New England



Source: U.S. Energy Information Administration (EIA). Available at *https://www.eia.gov/outlooks/aeo/supplement/excel/suptab_2.1.xlsx. These projections are provided for illustrative purposes only and are not used to forecast avoided costs in AESC 2024.*

Recent New England LDC forecasts show annual growth in customer requirements ranging from 0.0 percent to 2.4 percent per year (see Table 13). For the 13 LDC forecasts shown, the weighted average increase in requirements over a five-year period is 1.4 percent per year.[20]

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 for 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

[20] Growth rates weighted by the annual planning load forecasts for 2022 to 2023.

Schedule MM-R1

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

- Finally, some New England LDCs have chosen not to adjust their forecasts to reflect state initiatives to reduce GHG emissions at this time.

Table 13. New England LDC natural gas requirements forecasts

Utility	CAGR (%)	2022-2023 forecast (Bcf)		Forecast period	Case or Docket Number
		Annual	*Design Day*		
National Grid	2.4%	136.0	1.437	2023 to 2027	MA DPU 22-149
Eversource Gas	0.9%	47.9	0.520	2022 to 2026	MA DPU 21-118
NSTAR Gas	1.5%	50.2	0.551	2022 to 2026	MA DPU 22-86
Liberty Utilities (MA)	0.9%	6.8	0.081	2022 to 2027	MA DPU 22-129
Berkshire Gas	0.9%	6.4	0.066	2023 to 2027	MA DPU 22-148
Fitchburg Gas	0.2%	2.3	0.024	2023 to 2027	MA DPU 23-25
CT Natural Gas	0.4%	35.7	0.363	2023 to 2027	CT PURA 22-10-03
Southern CT Gas	0.3%	33.9	0.336	2023 to 2027	CT PURA 22-10-03
Yankee Gas	1.5%	55.5	0.486	2023 to 2027	CT PURA 22-10-03
Rhode Island Energy	0.4%	36.1	0.399	2023 to 2028	RI PUC 22-06-NG
Liberty Utilities (NH)	0.9%	16.4	0.166	2023 to 2027	NH PUC DG 22-064
Northern Utilities	1.1%	21.3	0.144	2023 to 2027	ME PUC 22-00078
Vermont Gas	0.0%	7.2	0.072	2023 to 2027	VT PUC 21-0167-PET
Total		**455.7**	**4.645**		

New England region gas supply resources

Natural gas consumed in New England comes from three main sources: (1) domestic and Canadian gas transported into the region by pipeline, (2) LNG delivered by ship or by truck, and (3) supplemental supplies, such as propane and RNG. The amount of gas available to New England consumers on any day depends on:

- The operational capacity of the pipelines that deliver gas into New England minus the capacity reserved for markets in downstate New York and Atlantic Canada.
- Supply and send-out capacity of LNG import terminals.
- Storage inventory and production capacity of LNG and propane peaking facilities.
- The availability of gas from other sources, including RNG, compressed natural gas (CNG), and LNG transported from outside the region by truck.

Gas transmission pipelines

Six major natural gas pipeline systems deliver gas to New England markets (see Figure 7).

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

Schedule MM-R1

Algonquin Gas Transmission (AGT): AGT is a regional pipeline that extends from central New Jersey to the Boston area. AGT provides access to Gulf Coast production and Appalachian area storage through multiple pipeline connections in New Jersey, and receives Marcellus shale 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 TransCanada PipeLines (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.

Portland Natural Gas Transmission System (PNGTS): PNGTS receives natural gas from TCPL at the New Hampshire-Quebec border through capacity that TCPL holds on the Trans Quebec and Maritimes pipeline (TQM). 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 Nova Scotia to U.S. markets.[21] Gas deliveries from offshore Nova Scotia began in 2000 and ended in 2018. Today MNP is primarily an export pipeline supplying Atlantic Canada, and is the outlet for gas from the Saint John LNG terminal in New Brunswick. MNP receives gas from the Brunswick Pipeline at the Maine-New Brunswick border and connects with PNGTS at Westbrook, ME. MNP delivers gas into TGP at Dracut, MA, and to AGT at Salem, MA.

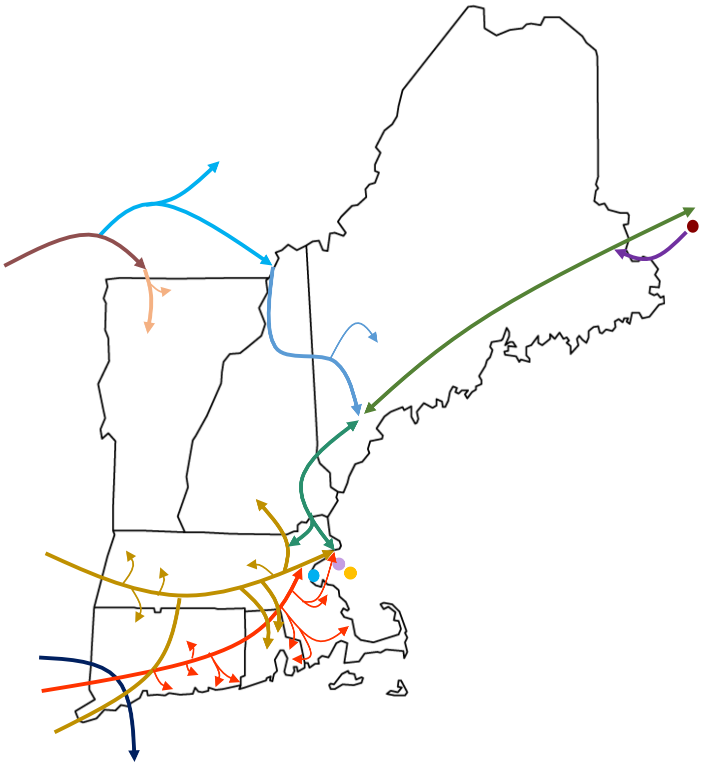
TransCanada PipeLines (TCPL): TCPL's Canadian Mainline extends from Alberta to Quebec. TCPL transports Western Canadian gas production and receives gas from the Dawn hub in southwestern Ontario through its connection with Enbridge Gas Inc. (formerly Union Gas Ltd.)[22] TCPL connects to IGTS and PNGTS and delivers gas directly to Vermont Gas System (VGS).

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

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

Schedule MM-R1

Figure 7. Natural gas pipeline infrastructure in New England and nearby regions



Source: Synapse Energy Economics, 2024.

Pipeline capacity into New England has expanded in recent years. Between January 2017 and the end of 2023, capacity into New England from New York and Quebec increased by just over 20 percent, from 3.3 Bcfd to 4.1 Bcfd (see Table 14). Adjusting for capacity that is reserved for markets in downstate New York and Atlantic Canada, the amount of pipeline capacity currently available for New England consumers is approximately 3.6 Bcfd.

Table 14. Pipeline capacity into New England (Bcfd)

Pipeline	2017	2023	Change
TGP	1.32	1.39	0.07
AGT	1.52	1.94	0.42
To Downstate NY	-0.32	-0.32	
To Atlantic Canada	-	-0.04	
Net Available	**1.20**	**1.58**	**0.38**
IGTS	0.21	0.21	-
PNGTS	0.21	0.46	0.25
To Atlantic Canada	-	-0.12	
Net Available	**0.21**	**0.34**	**0.13**
Vermont Gas	0.07	0.08	0.01
Capacity into New England	3.33	4.08	0.75
Net Available	**3.01**	**3.59**	**0.59**

Schedule MM-R1

Nearly all of the pipeline expansion activity has occurred on two paths (see Table 15). The Algonquin Incremental Market (AIM) and Atlantic Bridge expansion projects increased AGT capacity to transport Marcellus shale gas into New England from New Jersey and New York. The PNGTS Portland Xpress and Westbrook Xpress projects expanded the pipeline's capacity to receive gas from TCPL to supply Maine and New Hampshire and for delivery to MNP and TGP.

Table 15. Recent pipeline expansions in New England

Pipeline	Project	Capacity (Bcfd)	Description	Status
AGT	AIM	0.342	Expand from Ramapo, NY to New England citygates	Completed early 2017
AGT	Atlantic Bridge	0.133	Expand from Ramapo, NY to Salem, MA	Added 0.040 Bcfd in 2017, 0.093 Bcfd in 2019. Deliveries to MNP began in 2020.
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, ME and Dracut, MA	Completed 2020, 2021, and 2022

Pipeline operators have announced plans to expand pipeline capacity into New England from the Marcellus shale gas producing area and Canada on these same two paths.

- In September 2023 PNGTS notified the Federal Energy Regulatory Commission (FERC) that it will increase its certificated capacity to provide 0.059 Bcfd of additional transportation service, starting on or before April 1, 2024.[23] No new facilities are required on PNGTS, but future expansion by TCPL is expected.
- Millennium Pipeline held a binding open season for the Repurposing to Ramapo (R2R) project in late 2022. The R2R project would increase delivery capacity into the Ramapo, NY, interconnection with AGT by 0.125 Bcfd. The planned in-service date is November 1, 2025.
- In late 2023 AGT held an open season for the proposed Project Maple expansion. AGT would expand mainline capacity into New England from Ramapo, NY, by up to 500 Bcfd. The planned in-service date is 2031.

Liquefied natural gas import terminals

Because pipeline capacity into New England cannot supply all of the gas required on cold winter days, the region is dependent on supplies of LNG. Three LNG import terminals deliver gas into the New England market:

- **Distrigas of Massachusetts**: The Distrigas LNG terminal in Everett, MA, is currently owned by Constellation Energy. The facility has approximately 3.4 Bcf of storage and can deliver up to 0.7 Bcfd into TGP, AGT, and the National Grid

[23] FERC Docket No. CP23-548.

Schedule MM-R1

distribution system. The Everett terminal loads LNG into trucks to fill tanks at peaking facilities throughout the region and is the sole source of gas for Constellation's Mystic Generating Station.[24]

- **Northeast Gateway**: Excelerate Energy's Northeast Gateway is an offshore LNG receiving facility that injects gas directly into the AGT HubLine from specialized ships with onboard vaporization. Northeast Gateway began operating in 2008, but it has received only a few winter-season shipments in recent years.

- **Saint John LNG**: The Saint John LNG terminal (previously called Canaport) has close to 10 Bcf of storage capacity and can send out approximately 1 Bcfd. Repsol Energy North America uses 0.7 Bcfd of firm transportation capacity that it holds on MNP to sell gas at Dracut and Salem in Massachusetts. Several New England LDCs have contracts with Repsol to buy winter gas supplies at these points.[25]

Gas 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 16). The total design-day production capacity for these facilities is approximately 1.4 Bcfd. Many of the LDC peaking facilities have on-site storage, but others are satellite facilities that require mid-winter refill by truck.

Table 16. New England LDC peaking facilities (2022–2023 winter)

State	Type	Number of facilities	Aggregate Delivery Capacity (Bcf/day)	Aggregate Storage Capacity (Bcf)
Massachusetts	LNG	17	0.866	10.465
Connecticut	LNG	3	0.282	3.484
Rhode Island	LNG	2	0.119	0.802
New Hampshire	LNG	3	0.013	0.013
Maine	LNG	1	0.006	0.012
TOTAL LNG		**26**	**1.286**	**14.776**
Massachusetts	Propane	7	0.059	0.180
New Hampshire	Propane	3	0.035	0.108
Vermont	Propane	1	0.008	0.015
TOTAL PROPANE		**11**	**0.102**	**0.303**
Total On-System Peaking		**37**	**1.388**	**15.079**

[24] The planned retirement of the Mystic generating plant in 2024 has created uncertainty about the future operation of the Distrigas terminal.

[25] For example, the Massachusetts DPU approved multi-year contracts between Repsol and Eversource Gas for up to 47,000 MMBtu per day and 1,551,000 MMBtu per winter season in Docket No. 17-172.

Compressed natural gas

Several companies operate compression facilities in New England that fill large-capacity truck trailers with CNG.[26] 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, a source of supply during system repairs, or a source of gas supply for isolated market areas.

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 can also increase the requirement for gas supply resources and distribution capacity. Alternatively, CNG 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.

Renewable natural gas

RNG is pipeline-quality gas extracted from landfills or produced from waste material using anaerobic digesters. Substituting RNG for natural gas is regarded as a means of reducing GHG emissions.

To meet decarbonization targets, which typically culminate with a goal of achieving net-zero emissions by 2050, some LDCs have proposed blending or fully replacing fossil fuel natural gas with RNG. As an example of actions LDCs are taking, in May 2022, National Grid issued an RFI for RNG to be delivered in Massachusetts and New York.[27] Regulatory approval to increase RNG purchases will put upward pressure on RNG prices, and thus its price premium over conventional natural gas. It will also increase concerns about the availability of RNG.

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.[28] Both programs currently use RNG produced outside of New England.[29]

Projects to supply RNG to New England LDCs and other end users include:

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[26] 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.

[27] National Grid. 2022. "National Grid's first-of-its-kind renewable energy RFI validates a fossil-free energy strategy for the Northeast," Available at: https://www.nationalgridus.com/News/2022/08/National-Grid-8217-s-first-of-its-kind-renewable-energy-RFI-validates-a-fossil-free-energy-strategy-for-the-Northeast/.

[28] Summit Natural Gas Maine. "A Program to help Build a Sustainable Energy Future." *summitnaturalgas.com.* Available at: https://www.summitnaturalgasmaine.com/RenewableNaturalGas.

[29] 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.

- An anaerobic digester facility operating at a dairy farm in Salisbury, VT, utilizes food waste and animal manure to generate 140,000 Mcf per year. Middlebury College[30] and the gas utility, VGS, purchase the RNG generated.[31]

- 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.[32] The facility is expected to be in full operation by the end of 2023.

To develop the RNG price forecast and emissions estimate in this report, we utilized externally derived estimates of RNG production by region, RNG price by feedstock, and carbon intensity by feedstock. In the following section, we will discuss each element.

The first estimate reviewed is RNG production. National estimates for RNG production are limited. For this report, we use the projection calculated in a 2019 comprehensive study by ICF[33] that estimated RNG potential and costs for all regions and states in the United States. These estimates were calculated for three scenarios: low resource potential, high resource potential, and technical potential. According to the IFC report, by 2040, New England is projected to generate around 2 percent of the total RNG production in the country in the three scenarios. New England RNG is generated mostly from landfill gas, municipal solid waste (MSW), and animal manure.[34] Table 17 shows the high resource potential estimates from this study.[35]

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

[31] VGS. Last accessed October 26, 2023. "Renewable Natural Gas." *Vgsvt.com*. Available at https://vgsvt.com/climate/renewable-natural-gas/.

[32] *Request For Approval of Affiliated Interest Transaction for a Special Rate Agreement, Natural Gas Sale and Purchase Agreement, and Interconnection Agreement With Peaks Renewables, Inc Pertaining To Summit Natural Gas of Maine, Inc*, Docket No. 2020-00089, Maine Public Utilities Commission. SNGME will buy the gas produced by the facility, but not the RNG Attributes. Peaks Renewables is an affiliate of SNGME.

[33] ICF. 2019. *Renewable Sources of Natural Gas: Supply and Emission Reduction Assessment*. Available a: https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf.

[34] Id, page 13-14.

[35] The 2019 ICF report on RNG only showed resource potential as of 2040. We made downward adjustments in the RNG available for the years before 2040 based on the supply curves for each feedstock.

Schedule MM-R1

Table 17. High resource potential scenario for RNG in 2040 (TBtu/year)

	New Eng-land	Mid-Atlan-tic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Moun-tain	Pacific	Total
RNG from biogenic or renewable resources										
LFG	21.7	94.3	173.8	47.3	145	59.1	106.2	32.9	155.2	854.6
Animal Manure	16	24.2	60.6	88.9	63.4	37.7	71.9	57.5	42.1	462.3
WRRF	1.6	6.3	6.6	2	5.1	1.6	3.1	1.7	5.5	33.5
Food Waste	3.1	8.8	9.9	4.1	13.1	4.2	8	2.9	9.8	63.9
Sub-Total, AD	**42.4**	**133.6**	**250.9**	**142.3**	**226.6**	**102.6**	**189.2**	**125**	**212.6**	**1425.3**
Ag Residue	0.1	9.2	142.6	361	26.9	7.3	28.8	27.3	37.3	640.5
Forest Residue	7.3	9.7	19.3	13	75.2	41.3	37.1	19.3	13.6	235.8
Energy Crops	0.5	9.4	64.4	260	77.3	91.6	330.5	3.9	0	837.6
Sub-Total, TG	**7.9**	**28.3**	**226.3**	**634**	**179.4**	**140.2**	**396.4**	**50.5**	**50.9**	**1,713.9**
Renewable gas from MSW										
MSW	32.4	91.6	103.4	46.1	136.3	43.2	83.2	50.1	108.5	694.8
RNG from P2G / Methanation										
P2G / Methanation										678.7
Totals	**80.5**	**245.2**	**569.4**	**819.4**	**532**	**283.5**	**658.1**	**222.5**	**359.4**	**4,512.6**

Source: Reproduced from ICF. 2019. Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment.

The second estimate reviewed is RNG cost by feedstock. We relied on the estimates developed by ICF, which are based on assumptions of capital expenditures and operational costs for RNG production for each feedstock and the production technology utilized.[36] RNG from landfill gas and water resource recovery facilities (WRRF) are produced with anaerobic digestion and are the most cost-effective.[37] RNG produced using thermal gasification are more expensive, as the technology is still immature.[38] Table 18 shows these estimates. Another RNG supply curve was generated by E3 for the Massachusetts

[36] ICF. 2020. *Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington DC Metro Area*. Page 67-69. Available at: https://www.washingtongas.com/-/media/3a5633e2c3c64ed08fe1ef96c65d8207.pdf.

[37] Anaerobic digestion is the process where organic matter is broken down by bacteria. This is the process through which RNG is produced from manure, wastewater, and food waste.

[38] Thermal gasification applies high heat to break down organic molecules into biogas and carbon dioxide. This can be utilized for drier feedstocks such as agricultural and forest residue.

Department of Public Utilities (DPU) that similarly shows the lowest-cost RNG is generated from landfill gas and wastewater treatment facilities.[39]

Notably, the RNG cost ranges in Table 18 only include RNG produced from anaerobic digestion and thermal gasification; they do not include cost estimates for synthetic natural gas (SNG), which is produced from hydrogen combined with CO_2 from biowaste (SNG-bio) or direct air-capture (SNG-DAC). This report's synthetic natural gas price projections are based on hydrogen and SNG cost estimates produced by E3 and Scott Madden in 2022, reduced by production tax credits (PTC) for hydrogen (see the discussion on hydrogen in the following section).

Table 18. RNG cost ranges by feedstock (2024 $ per MMBtu)

	Low	High
Landfill Gas	$8.64	$23.12
Animal Manure	$22.39	$39.66
WRRF	$9.00	$31.76
Food Waste	$23.60	$34.43
Agricultural Reside	$22.27	$33.34
Forest Residue	$21.05	$35.53
Energy Crops	$22.27	$37.96
MSW	$21.05	$53.78

Source: ICF. March 2020. Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington DC Metro Area. Adjusted to 2024 dollars.

We calculate the emissions factors in this report based on a lifecycle analysis approach, with carbon intensity values from the California Low Carbon Fuel Standard (LCFS) program. Carbon intensity is the measure of GHG emissions associated with producing, distributing, and consuming fuel and is measured in carbon dioxide equivalent (CO2e) per unit of energy. Landfill gas and MSW both have positive emission factors. Animal manure can have positive or negative emissions factors depending on the source. Production methods such as the collection and processing of cow manure prevent the release of fugitive CH_4, thus showing negative carbon intensities. This study assumes the emissions factor for SNG to be zero.[40]

For AESC 2024, we developed a price forecast and emissions rate time series based on the three characteristics previously discussed (shown in Table 20). The average price and emissions rate change based on the mix of feedstock from which RNG is generated. This is based on the estimated availability of feedstock per year relative to the availability of feedstock in 2040. For example, in 2025, we assume that 50 percent of the landfill gas potential for 2040 is available, while only 20 percent of the 2040 potentials for feedstock from animal manure, WRRF, and food waste are available. In 2025, we assume

[39] E3, Scott Madden. 2022. *The Role of Gas Companies in Achieving the Commonwealth's Climate Goals: Independent Consultant Report*. Available at https://thefutureofgas.com/content/downloads/2022-03-21/3.18.22%20-%20Independent%20Consultant%20Report%20-%20Decarbonization%20Pathways.pdf.

[40] ICF. 2020. *Study on the Use of Biofuels (Renewable Natural Gas) in the Greater Washington DC Metro Area.* Page 88. Available at https://www.washingtongas.com/-/media/3a5633e2c3c64ed08fe1ef96c65d8207.pdf.

Schedule MM-R1

that RNG from agricultural residue, forest residue, energy crops, and MSW are not yet available. By 2040, 100 percent of the resource potential from each feedstock is assumed to be available. For RNG requirements that exceed RNG produced from these feedstocks, we assume it will be fulfilled by higher-cost synthetic natural gas, with the lower cost SNG-bio utilized first and then SNG-DAC.[41]

Table 19. Hydrogen and SNG cost ranges (2024 $ per MMBtu)

	2030	2040	2045	2050
SNG-Bio	32.33	45.87	48.00	44.52
SNG-DAC	60.13	72.82	74.51	70.60

Source: Based on E3 and Scott Madden. March 2022. The Role of Gas Companies in Achieving the Commonwealth's Climate Goals: Independent Consultant Report – Appendix 4. Available at https://thefutureofgas.com/sep March 2022. Adjusted for IRA tax credits. In 2024 $.

Table 20. RNG price forecast (2024 $ per MMBtu) and emission rate estimates

	RNG price forecast (SNG only) *(2024 $/MMBtu)*	Blended RNG price forecast *(2024 $/MMBtu)*	SNG only lifecycle emissions rate *(lb CO_2e/MMBtu)*	Average lifecycle emissions rate *(lb CO_2e/MMBtu)*
2024	$32.34	$22.86	0	59
2025	$32.34	$23.55	0	53
2026	$32.34	$24.25	0	46
2027	$32.34	$24.94	0	40
2028	$32.34	$25.63	0	33
2029	$32.34	$26.32	0	27
2030	$32.34	$27.01	0	20
2031	$31.47	$28.26	0	21
2032	$30.59	$29.51	0	22
2033	$32.51	$30.97	0	21
2034	$34.42	$32.58	0	19
2035	$36.33	$34.22	0	18
2036	$38.24	$35.28	0	17
2037	$40.15	$36.65	0	15
2038	$42.06	$37.89	0	14
2039	$43.97	$39.26	0	14
2040	$45.88	$40.84	0	13
2041	$50.52	$43.96	0	12
2042	$55.16	$47.51	0	11
2043	$57.02	$49.16	0	10
2044	$58.87	$51.03	0	10
2045	$60.73	$52.73	0	9
2046	$60.38	$52.89	0	9
2047	$60.03	$53.03	0	8
2048	$59.68	$53.21	0	8
2049	$59.33	$53.22	0	7
2050	$58.98	$53.23	0	7

Note: Blended percentage based on the amount of RNG that would be hypothetically required in Massachusetts in Counterfactual #1, a future with no incremental energy efficiency or building decarbonization measures installed after 2023. See Section 4.8: Embedded emissions regulations *for more information on the assumptions used for estimating the avoided costs related to Massachusetts greenhouse gas emissions sublimits. Lifecycle emission rates for SNG are assumed to be zero due to an*

[41] This approach is consistent with the Independent Consultant's Report for the Massachusetts Department of Environmental Protection.

Schedule MM-R1

assumption that all feedstock is produced via renewable energy. Lifecycle emission rates for blended RNG are positive because they are predominantly made up of RNG sources that have positive emission rates. The costs and emissions in the "blended" columns differ based on the selected counterfactual, although differences tend to be small.

Hydrogen

The United States currently produces roughly 10 percent of the world's hydrogen, predominately by refining hydrocarbons (petroleum and natural gas) into hydrogen. Existing hydrogen infrastructure is centered on the Gulf Coast, where hydrogen is used in the manufacture of ammonia and chemicals. There is currently an interest in developing the production and use of zero- and low-carbon hydrogen. This is driven by the potential of clean hydrogen to contribute to national and state decarbonization goals.

There are several ways to produce hydrogen and color names are used to distinguish hydrogen categories through their production methodology. Grey hydrogen, currently the predominant form of hydrogen, is created from natural gas using steam CH_4 reformation. There are several zero- or low-carbon production methodologies for hydrogen. Blue hydrogen is grey hydrogen but with the addition of carbon capture and sequestration (CCS) technology. Green hydrogen is produced by using renewable energy to power the electrolysis of water; this is the focus of hydrogen in AESC 2024 given its overall low or zero impact to emissions.

There are significant U.S. Department of Energy (DOE) initiatives and government subsidies available to develop green hydrogen. In April 2023, the States of New York, New Jersey, Maine, Rhode Island, Connecticut, Vermont, and Massachusetts announced the submission of the group's proposal for a Northeast Regional Clean Hydrogen Hub to the U.S. Department of Energy to compete for a $1.25 billion share of the $8 billion in federal subsidies. On October 13, 2023, the DOE announced the projects selected under this program, which did not include the Northeast Regional Clean Hydrogen Hub.[42]

The DOE's key strategy is to "target strategic, high-impact uses for clean hydrogen."[43] Hydrogen is to be used in the "highest value applications, where limited deep decarbonization alternatives exist." These include the industrial sector, such as chemicals, steel and refining, transportation and energy storage.[44] Certain natural gas utilities have also identified blending hydrogen with pipeline natural gas as a strategy to help meet decarbonization targets. For more on assumptions related to hydrogen, see Section 4.8: *Embedded emissions regulations*.

For AESC 2024, we rely on the projections shown in Figure 8. The Synapse Team developed these projections after a thorough literature review that included market research and analysis. Low-carbon

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[42] U.S. Department of Energy. "Regional Clean Hydrogen Hubs Selection for Award Negotiations." *Office of Clean Energy Demonstrations* .Available at: https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations.

[43] U.S. Department of Energy. 2023. *U.S. National Clean Hydrogen Strategy and Roadmap: Executive Summary*. Page 1. Available at https://www.hydrogen.energy.gov/pdfs/us-national-clean-hydrogen-strategy-roadmap.pdf.

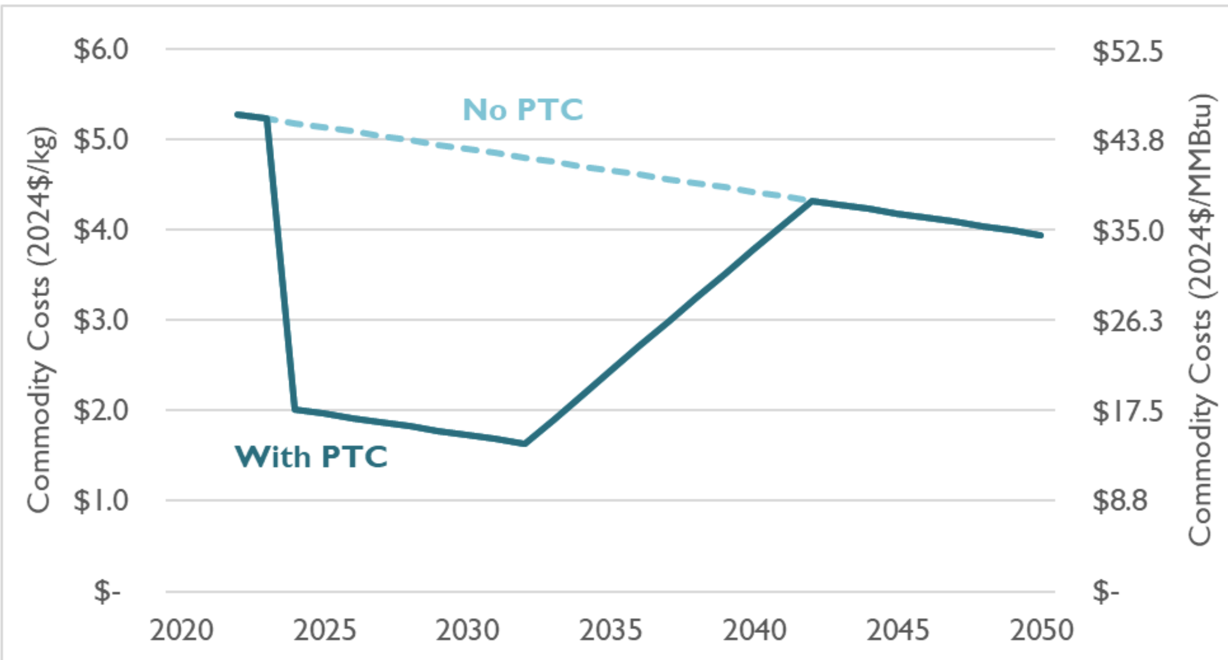
[44] Id. Page 2.

Schedule MM-R1

hydrogen is a nascent industry and there are significant uncertainties in projecting future commodity prices. For example, the U.S. Treasury Department has delayed publishing its guidance on how the PTC introduced in the IRA will be implemented.[45] This PTC has a value of $3 per kg for low-carbon hydrogen, significantly impacting the economics of projects that qualify and the hydrogen economy at large.

Our forecast projects modest unsubsidized hydrogen cost declines, beginning in 2022 at a price of $5.28 per kg ($46.39 per MMBtu) in 2024 dollars and reaching a 2050 price of $3.97 per kg ($34.69 per MMBtu), consistent with the IEA's cost projections for low-carbon hydrogen production.[46] The prices include a $3 per kg ($26.38 per MMBtu) PTC for 2024 through 2032. To account for projects that come online after 2024, and thus qualify for PTCs past 2032, we assume the tax credit's effect on market prices reduces 10 percent per year until it is fully phased out in 2042.[47]

Figure 8. Hydrogen price trajectories



[45] Pontecorvo, E., Myere, R. 2023. "The Clean Hydrogen Rules Will Be Delayed Until at Least October." *Heatmap*. Available at https://heatmap.news/economy/hydrogen-tax-credit-rules-when.

[46] See, for example, International Energy Agency. 2020. "Global average levelized cost of hydrogen production by energy source and technology, 2019 and 2050." Available at https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050, and PWC, "The Green Hydrogen Economy: Predicting the Decarbonisation Agenda of Tomorrow." Available at https://www.pwc.com/gx/en/industries/energy-utilities-resources/future-energy/green-hydrogen-cost.html#data-explorer-tool\

[47] Some Study Group members suggested that the 45V PTC could get extended past 2032. While this is possible, it would likely be after several years of the credit having been implemented and is not an assumption made here. However, as noted in the text, the PTC will persist past 2032 for qualifying facilities that come online after 2023.

Schedule MM-R1

2.4. Avoided natural gas cost methodology

AESC 2024 uses the same avoided cost methodology used for AESC 2021, 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 (C&I) 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. C&I non-heating
3. C&I heating
4. Residential heating
5. Residential water heating
6. Residential non-heating
7. All C&I
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 2021 as detailed below:[48]

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 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.

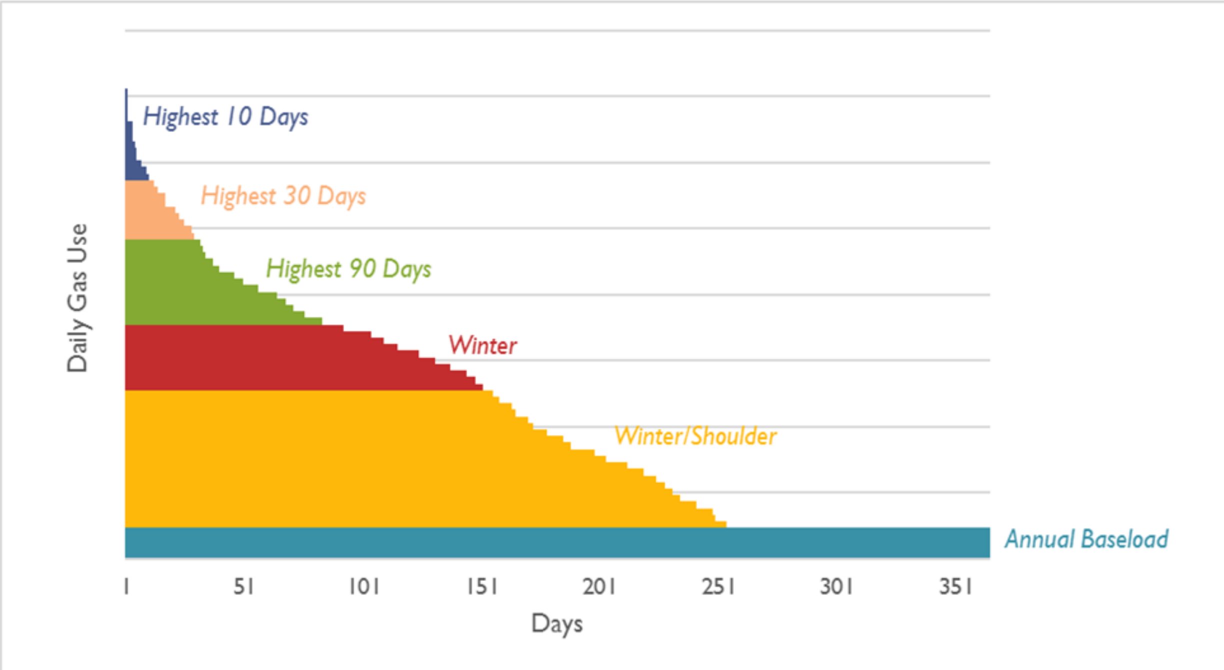
We calculate the load shares for each end-use type from a load curve that combines a representative gas use equation (base use per day and use per heating degree day, or HDD) and a representative HDD distribution.[49] Figure 9 illustrates this with a sample load curve for the C&I Heating end-use category. 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

[48] 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).

[49] The residential, commercial, and industrial load curves reflect current gas use. We do not try to forecast the impact of electrification on gas use per HDD in future years.

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 9. 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. We repeat this calculation for each end-use type, for each year of the forecast period as illustrated in Table 21.

Table 21. 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.

Schedule MM-R1

New England regions

This study estimates natural gas avoided costs 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. For residential end uses, we rely on the National Renewable Energy Laboratory's end-use load profiles (EULPs) from its residential building stock model *ResStock*.[50] We analyze the relationship between daily average temperatures and end-use energy consumption to determine the portion of end-use energy use that is *base use* versus that which is *temperature-sensitive*. Because NREL does not publish EULPs for the industrial sector, we use the base use per day and use per HDD factors by end-use category that were provided by study sponsors in AESC 2021 for C&I end uses.[51] We use the same load share factors for all regions. Table 22 shows the proportions of baseload and temperature-sensitive gas use for the five end-use categories.

Table 22. Base use and heating factors by end use

End use	Base use (Percent)	Temperature sensitive (Percent)
Residential Heating	3%	97%
Residential Water Heating	86%	14%
Residential Non-Heating	89%	11%
Commercial & Industrial Heating	21%	79%
Commercial & Industrial Non-Heating	68%	32%

Natural gas transmission costs

AESC 2024 measures transmission costs using the rates that New England LDCs pay to upstream pipelines for firm transportation services. These rates include a fixed reservation charge applied to the daily contract quantity and a variable charge 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.

Because the cost to build new pipeline facilities is generally higher than the costs of the depreciated assets 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.

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[50] For more information on NREL's ResStock database, see https://resstock.nrel.gov/.

[51] 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.

Schedule MM-R1

The avoided cost estimates in AESC 2024 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. 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 2024

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>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 from 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 this will continue.

The costs for this option are based on Enbridge Gas and TCPL 2023 transportation rates and projected PNGTS expansion costs (see Table 23). 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. The gas commodity cost is the projected Dawn Hub price.

Table 23. Transmission costs for the Dawn Hub capacity path

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
Enbridge Gas	Dawn Hub	Parkway	0.096	0.003	0.9%
TCPL	Parkway	VGS	0.422	0.0	1.09%
TCPL	Parkway	PNGTS	0.5378	0.0	1.5%
PNGTS	TCPL	Dracut	0.82	0.0	1.3%
TGP	Dracut	TGP Zone 6	0.133	0.029	0.2%

<u>Marcellus supply via AGT</u>

Gas is purchased close to the Marcellus shale gas producing areas in Pennsylvania and transported on Millennium Pipeline to the Ramapo, NY, interconnect with AGT (see Table 24). The transportation costs for Millennium and AGT are the indicative prices for the R2R and Project Maple expansions. Northern New England LDCs have additional transportation on MNP. The Millennium East Pool index is used as the representative price for gas purchased at Millennium receipt points.

Schedule MM-R1

Table 24. Transmission costs for the Marcellus capacity path

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
Millennium	Marcellus	Ramapo	0.65	0.002	0.7%
AGT	Ramapo	Salem	2.75	0.000	4.4%
MNP	Salem	NH or ME	0.42	0.000	0.9%

Ramapo supply via AGT

Gas is purchased at the Ramapo, NY, receipt point on AGT. Transportation costs are as shown in Table 24. The TETCO M3 index is used as the representative price for gas purchased at Ramapo.

Dracut supply via TGP (Southern New England)

Gas is purchased at Dracut, MA and transported on TGP to the LDC city gate (see Table 25). We assume LDCs contract for winter season supply priced at the AGT Citygates index plus a premium.

Table 25. Transmission costs for Dracut supply

Transporter	Receipt	Delivery	Fixed Cost ($/MMBtu)	Variable Cost ($/MMBtu)	Fuel (Percent)
TGP	Dracut	TGP Zone 6	0.133	0.029	0.2%

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 premium.

On-system peaking resources

For AESC 2024, the peaking resource cost for Southern New England is based on the operating cost for a typical one Bcf LNG storage and peaking facility. The commodity cost is the average AGT Citygates price plus a variable cost for liquefaction and vaporization. For Northern New England, which is more dependent on satellite LNG and propane peaking facilities, the peaking resource cost is based on costs from the LDCs' peaking service demand rate filings (see next section) and the commodity cost is the average AGT Citygates price for the peak winter months plus a premium. Peaking costs for Vermont are based on a forecast of propane prices plus a variable operations and maintenance (O&M) cost. .

Design day avoided costs

AESC 2024 includes design day avoided cost estimates for all three New England regions. This is a change from AESC 2021, which only showed design day costs for Vermont.[52] The design day avoided

[52] The Synapse Team wrote a supplemental study in 2021 that calculated design day avoided costs for Southern New England and Northern New England using the Highest 10 Day avoided costs from the AESC 2021 report. Knight, P., Chang, M., Hall, J., Rosenkranz, J. 2021. *AESC 2021 Supplemental Study: Expansion of Natural Gas Benefits*. Synapse Energy Economics for AESC Supplemental Study Group. Available at https://www.synapse-energy.com/sites/default/files/AESC_2021_Expansion_of_Natural_Gas_Benefits_21-074.pdf.

Schedule MM-R1

costs for Southern New England and Northern New England have two components. The non-commodity component is a weighted average cost derived from the peaking resource demand rates that the LDC charge marketers for company-managed peaking supplies under their retail choice programs. These rates recover supplier demand charges and variable operating costs associated with LDC-operated LNG and propane peaking facilities, and the demand charges LDCs pay under contracts for firm winter peaking supplies. The avoided commodity cost component is the average New England market price for the months of November through March.[53]

This approach to calculating design day avoided gas costs has several advantages: (1) peaking demand rates are based on the costs of the peak-period supply resources that each LDC actually uses, (2) the peaking demand rates are publicly available, and (3) the costs that go into the LDCs' peaking demand rates are recent estimates for the same time period (2023–24 winter) and are subject to review by the state utility commissions before the rates are approved. The same costs are used to calculate the avoided cost per MMBtu from reducing gas use by the same daily amount for periods of two through ten days.

Other sources of natural gas supply

There are other sources of natural gas supply that do not enter into the AESC 2024 avoided cost calculations.

<u>Underground gas storage</u>

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 2021, we do not include storage service costs in the natural gas avoided cost estimates.

<u>Compressed natural gas, renewable natural gas, and hydrogen</u>

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.

[53] This is similar to the methodology used by National Grid to calculate marginal gas supply costs for its downstate New York utilities. *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY*, New York Public Service Commission Case No. 23-G-0225, Direct Testimony of Gas Supply Panel. Page 32. Available at: <u>documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=23-G-0225</u>.

Connecticut LDCs are required to have standard RNG interconnection rules to facilitate future RNG production in that state.[54] 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 2024 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.[55] 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 included in system gas supply. Because VGS' RNG attribute purchases are tied to increases or decreases in customer requirements, RNG costs are included in the avoided costs for Vermont.

For more discussion on compressed natural gas, RNG, and hydrogen, see Section 2.3: *New England natural gas market*.

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 3 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. AESC 2024 uses a LAUF factor of 2 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.

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

[54] *Adoption of Gas Quality and Interconnection Standards for the Injection into the Natural Gas Distribution System of Conditioned Biogas Derived from Organic Material*, Docket No. 19-07-04, Connecticut Public Utilities Regulatory Authority.

[55] Investigation into the tariff filing of Vermont Gas Systems, Inc., proposing a change in rates and use of the System Expansion and Reliability Fund, Vermont Public Utility Commission Case No. 20-0431-TF, Direct Testimony of Todd Lawliss. Page 12.

contracts. AESC 2024 uses the results from marginal cost studies included with New England LDC rate case filings (Table 26).

Table 26. 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 (2021 $/MMBtu)		0.960	1.386	0.779	1.407	
Weighted Average (2024 $/MMBtu)		**1.083**	**1.564**	**0.880**	**1.588**	

2.5. Avoided natural gas costs by end use

A summary of the natural gas avoided cost estimates is shown in Table 27, Table 28, and Table 29. Avoided costs are developed for three regions: southern New England (Connecticut, Massachusetts, Rhode Island), northern New England (Maine, New Hampshire), and Vermont. Vermont appears 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 2021.

Table 27. Avoided costs of gas for retail customers by end use assuming no avoidable margin (2024 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end uses
	Non-Heating	*Hot Water*	*Heating*	*All*	*Non-Heating*	*Heating*	*All*	
Southern New England								
AESC 2021	$5.27	$6.23	$8.38	$7.48	$6.32	$7.75	$7.13	$7.32
AESC 2024	$4.89	$4.93	$7.22	$6.41	$5.58	$6.99	$6.37	$6.39
2021 to 2024 change	*-7%*	*-21%*	*-14%*	*-14%*	*-12%*	*-10%*	*-11%*	*-13%*
Northern New England								
AESC 2021	$5.09	$6.09	$8.33	$7.39	$6.19	$7.66	$7.02	$7.22
AESC 2024	$4.76	$4.80	$7.21	$6.36	$5.47	$6.89	$6.27	$6.32
2021 to 2024 change	*-7%*	*-21%*	*-13%*	*-14%*	*-12%*	*-10%*	*-11%*	*-12%*

Notes: AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent. AESC 2024 levelized costs are for 15 years (2024–2038) at a discount rate of 1.74 percent.

Schedule MM-R1

Table 28. Avoided costs of gas for retail customers by end use assuming some avoidable margin (2024 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end uses
	Non-Heating	*Hot Water*	*Heating*	*All*	*Non-Heating*	*Heating*	*All*	
Southern New England								
AESC 2021	$6.41	$7.37	$10.03	$8.95	$7.26	$9.43	$8.48	$8.73
AESC 2024	$5.97	$6.01	$8.79	$7.81	$6.46	$8.57	$7.65	$7.73
2021 to 2024 change	*-7%*	*-18%*	*-12%*	*-13%*	*-11%*	*-9%*	*-10%*	*-11%*
Northern New England								
AESC 2021	$6.23	$7.23	$9.97	$8.86	$7.12	$9.34	$8.37	$8.63
AESC 2024	$5.84	$5.88	$8.77	$7.75	$6.35	$8.48	$7.55	$7.66
2021 to 2024 change	*-6%*	*-19%*	*-12%*	*-13%*	*-11%*	*-9%*	*-10%*	*-11%*

Notes: AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent. AESC 2024 levelized costs are for 15 years (2024–2038) at a discount rate of 1.74 percent.

Table 29. Avoided cost of gas for retail customers on a design day (2024 $ per MMBtu)

Design Day Avoided Costs	
Southern New England	
Without Retail Margin	$225.64
With Some Retail Margin	$406.95
Northern New England	
Without Retail Margin	$352.23
With Some Retail Margin	$533.54

Notes: AESC 2024 levelized costs are for 15 years (2024–2038) at a discount rate of 1.74 percent.

Table 30. Avoided costs of gas for retail customers by end use for Vermont (2024 $ per MMBtu)

	All sectors			
	Design Day	*Peak Days*	*Remaining Winter*	*Shoulder/ Summer*
Vermont				
AESC 2021	$627.79	$19.28	$5.77	$5.36
AESC 2024	$539.16	$21.16	$5.23	$4.84
2021 to 2024 change	-14%	10%	-9%	-10%

Notes: AESC 2021 levelized costs are for 15 years (2021–2035) at a discount rate of 0.81 percent. AESC 2024 levelized costs are for 15 years (2024–2038) at a discount rate of 1.74 percent.

Southern New England and Northern New England

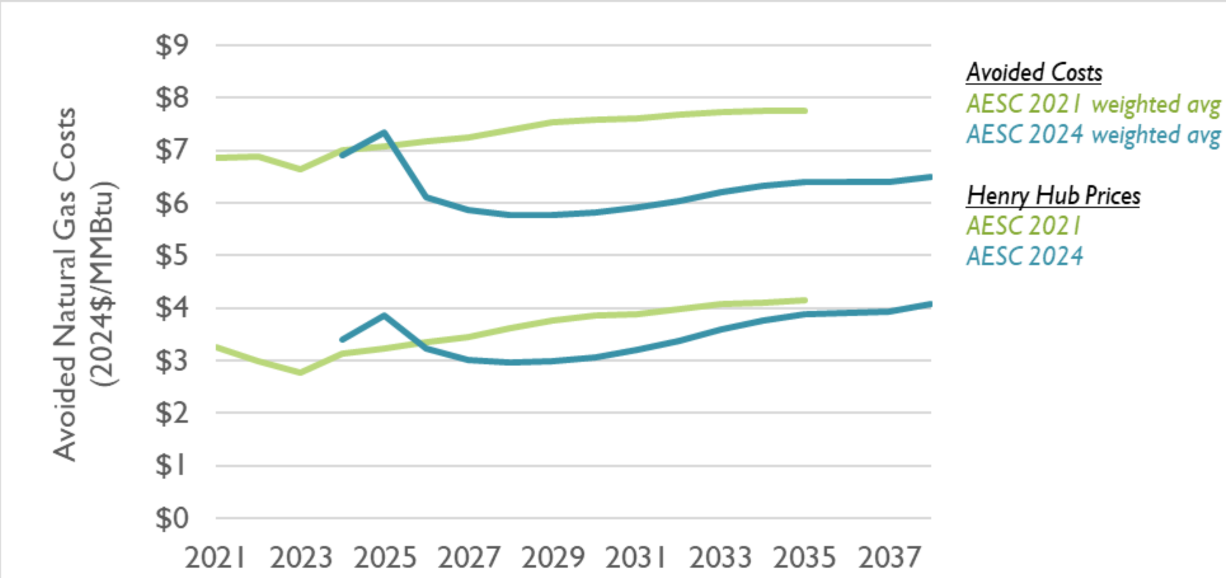
The avoided natural gas cost estimates for Southern New England and Northern New England are lower for AESC 2024 when compared to the AESC 2021 results. There are two main reasons for this. The first reason is the reduction in gas commodity prices. The Henry Hub price forecast for AESC 2024 is lower than the AESC 2021 forecast, and gas purchased at upstream supply points such as the Dawn Hub is projected to be priced at a larger discount to the Henry Hub benchmark price.

Second, the AESC 2024 avoided gas costs are lower than the AESC 2021 avoided costs in real dollar terms because the marginal gas transmission costs associated with the Dawn and Dracut supply resources, which are significant drivers for both the AESC 2021 and AESC 2024 avoided cost results, are

Schedule MM-R1

largely unchanged in nominal dollars. This means that the gas transmission costs used for AESC 2024 are approximately 13 percent lower than the AESC 2021 costs when adjusted for inflation.

Figure 10. Comparison of avoided natural gas costs for Southern New England and Henry Hub prices



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 lower for AESC 2024 than for AESC 2021, due mostly to the change in the Canadian dollar exchange rate. The downstream LDC transmission cost is about 13 percent lower than it was in the previous study according to VGS, leading to an overall decrease in design day avoided costs. The avoided cost for the remaining nine peak days reflects the higher delivered cost of propane for the VGS peaking facility. The avoided costs for the remainder of the year are lower than in AESC 2021 due to long-term gas price trends at the Dawn hub, described earlier in Section 2.2 *Gas prices and commodity costs*.

Massachusetts emissions sublimits and the Clean Heat Standard

This section discusses the impact of Massachusetts' GHG emissions sublimits on avoided gas costs. For more information on the rationale and methods used information on this topic, see Section 4.8: *Embedded emissions regulations*. Table 31 shows that avoided natural gas costs are significantly higher under any scenario in which Massachusetts LDCs are required to blend substantial amounts of RNG into the gas distribution system. Under the blending required in Counterfactual #1 (a scenario that doesn't include any new heat pumps installed after 2023) the avoided costs are about 50 percent higher than what they would be in a scenario with no blending. Meanwhile, in Counterfactual #5 (a scenario that does include future heat pumps) avoided costs are about 20 percent higher.

Schedule MM-R1

We note that these costs should not be viewed in isolation. Because this methodology effectively embeds a GHG reduction policy (via an approximation of the forthcoming Clean Heat Standard), these incremental costs should be subtracted from the costs of GHG compliance. See the AESC 2024 *User Interface* and *Appendix G: Marginal Emission Rates* for calculating GHG impacts with and without these blending factors.

Table 31. Avoided costs of gas for retail customers by end use assuming some avoidable margin (2024 $ per MMBtu)

	Residential				Commercial & Industrial			All retail end uses
	Non-Heating	*Hot Water*	*Heating*	*All*	*Non-Heating*	*Heating*	*All*	
Southern New England								
No RNG Blend	$5.97	$6.01	$8.79	$7.81	$6.46	$8.57	$7.65	$7.73
Counterfactual #1	$9.52	$9.56	$12.07	$11.19	$9.93	$11.88	$11.03	$11.11

Note: All values are 15-year levelized costs.

Schedule MM-R1

3. FUEL OIL AND OTHER FUEL COSTS

In this chapter, we present the avoided fuel oil and other fuel costs used for AESC 2024, compare those estimates with AESC 2021, 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.[56] Also included are cord wood, wood pellets, kerosene, and propane in the residential heating applications, as well as 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 those in AESC 2021. Similar to AESC 2021, in AESC 2024 we follow the EIA STEO for one year and then directly transition to the 2023 AEO forecast. We chose the data sources for the near term to represent current market conditions.

3.1. Results and comparison with AESC 2021

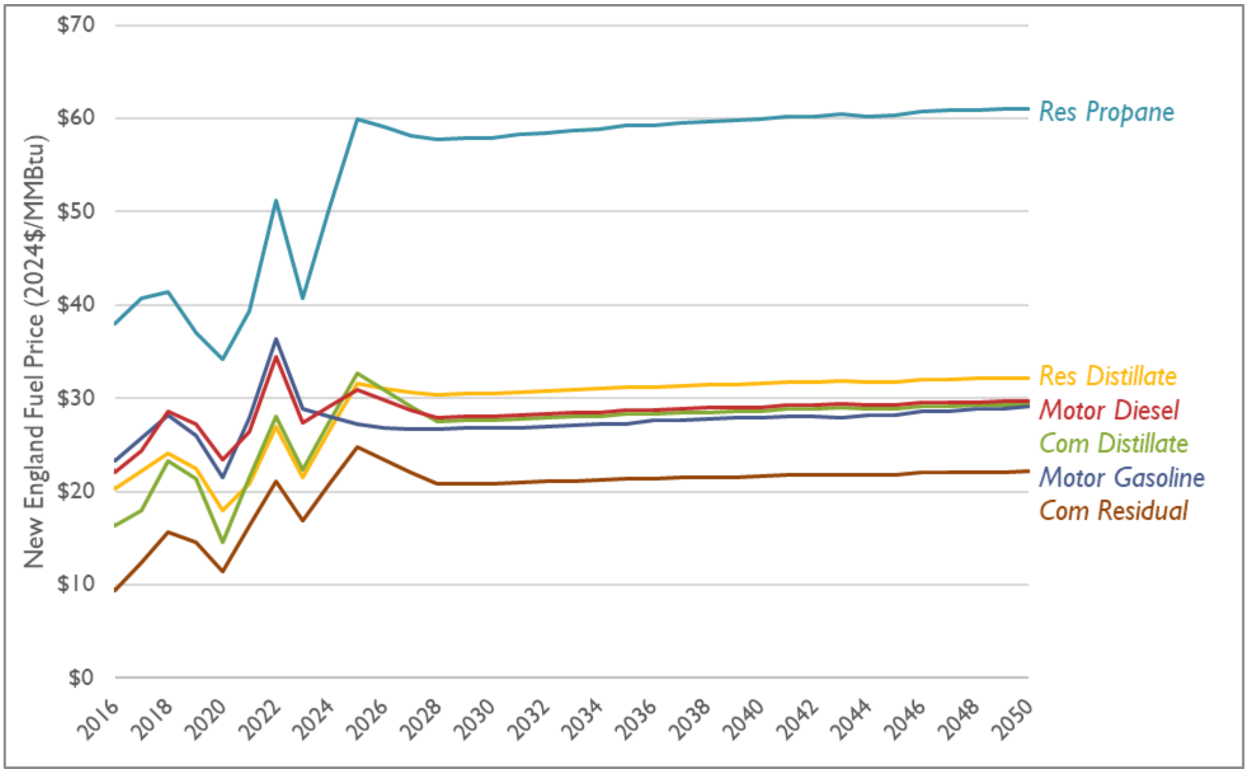
Table 32 compares the levelized avoided fuel costs for AESC 2024 with those used for AESC 2021. Annual avoided fuel costs are detailed in *Appendix D: Detailed Oil and Other Fuels Outputs*. This analysis uses EIA State Energy Data System (SEDS) values for the starting points, adjusted for current and near-term national prices based on the crude oil prices trends as discussed below. The prices then follow the trajectory of the EIA STEO and AEO 2023 Reference case projections for New England going forward.[57] The future prices for all fuels are very flat in terms of constant dollars over most of the AESC analysis period (see Figure 11).

[56] For the purposes of AESC 2024, biofuels blended in heating oil include B5 and B20.

[57] U.S. EIA. "State Energy Data System" *U.S. States: State Profiles and Energy Estimates*. Available at: https://www.eia.gov/state/seds/

Schedule MM-R1

Figure 11. Projections of fuel prices in New England



Compared to AESC 2021, residential distillate prices are 13 percent higher, while commercial distillate prices are 14 percent higher and commercial residual prices are 21 percent higher. Propane prices increased by 33 percent, representing current market conditions. Wood pellet prices increased by 21 percent while cordwood prices increased by 25 percent. Motor gasoline and diesel prices increased by 9 and 12 percent, respectively. New to this AESC, we include results for B50 biodiesel blends in addition to B5 and B20. Note that all these prices reflect the fuel heat content and do not adjust for relative efficiencies and delivered energy.

Table 32. Comparison of avoided costs of retail fuels (15-year levelized, 2024 $ per MMBtu)

	Residential								Commercial		Transportation	
	No. 2 Distillate	Pro-pane	Keros-ene	B5 Biofuel	B20 Biofuel	B50 Biofuel	Cord Wood (Delivered)	Wood Pellets	No. 2 Distillate	No. 6 Residual (low sulfur)	Motor Gasoline	Motor Diesel
AESC 2021 (2021–2035)	$27.14	$43.79	$33.41	$27.14	$24.42	-	$23.52	$25.36	$25.11	$17.77	$24.92	$25.70
AESC 2024 (2024–2038)	$30.60	$58.11	$38.47	$30.19	$25.58	$30.32	$29.37	$30.73	$28.59	$21.58	$27.16	$28.76
Change from AESC 2021 to AESC 2023	12.8%	32.7%	15.2%	11.2%	4.7%	-	24.9%	21.2%	13.8%	21.5%	9.0%	11.9%

Schedule MM-R1

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 2024, we rely on EIA's STEO and projections from the 2023 AEO Reference case (see Chapter 2: *Avoided Natural Gas Costs* for more information about the analogous gas price forecast). This is a similar methodology to that used in the 2021 AESC study.

For near-term projections in AESC 2024, we rely on data from the August 2023 STEO forecast for West Texas Intermediate (WTI) crude oil. We then transition to the AEO 2023 Reference case price projections in 2025. 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.

Although crude oil prices dropped during the COVID-19 pandemic as fossil fuel consumption fell world-wide and supply exceeded demand, they have since rebounded and are currently slightly higher than pre-pandemic levels. In the August 2023 edition of the STEO, the oil price forecast is about $80 per barrel through 2024. However, the uncertainty is quite large, as shown in Figure 12. We also reviewed the NYMEX oil futures for WTI,[58] which were occasionally used in past AESC studies to adjust or to verify the forecast. These values are similar to the August 2023 STEO in the near term, but then decline in both nominal and real dollar terms (see Figure 14). This is odd market behavior and probably not indicative of likely future prices. Thus, we make no use of NYMEX futures information in AESC 2024. For short-term prices, we rely on the STEO forecast because that incorporates an informed analysis of a wide variety of data, including the futures.[59]

[58] CME Group. "Crude Oil: Futures and Options." Available at: https://www.cmegroup.com/markets/energy/crude-oil/light-sweet-crude.quotes.html#venue=globex,

[59] U.S. EIA. "Short Term Energy Outlooks". Available at: https://www.eia.gov/outlooks/steo/marketreview/crude.php.

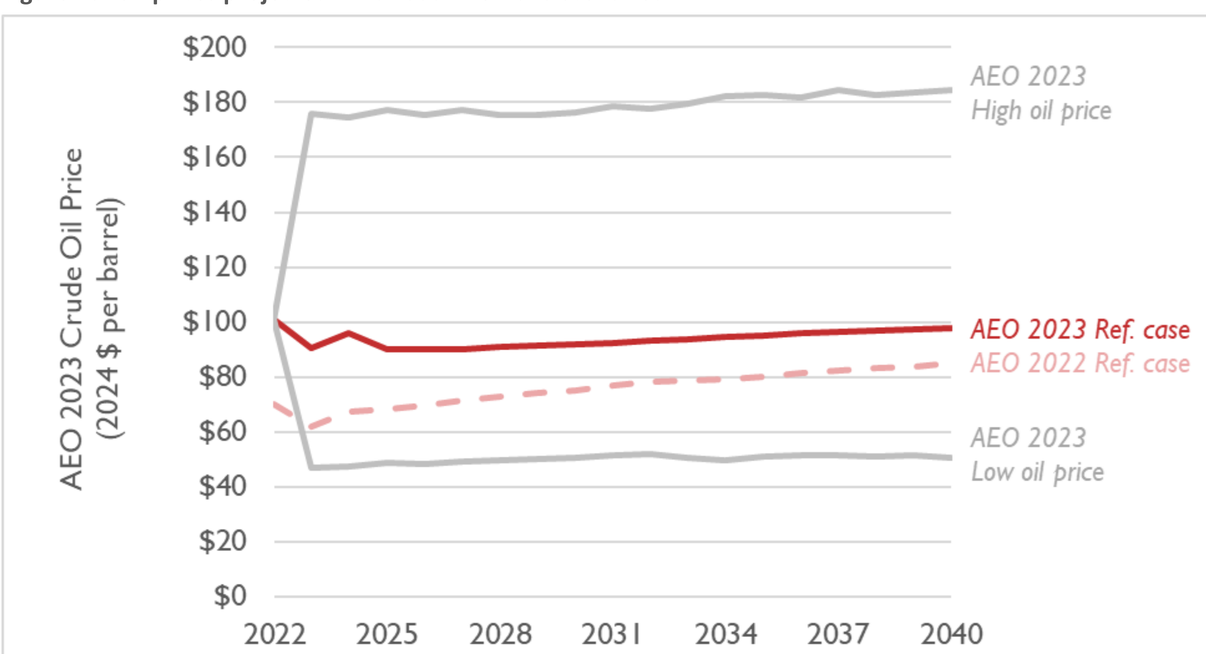
Schedule MM-R1

Figure 12. Forecast for West Texas Intermediate crude oil with NYMEX confidence intervals

Source: Reproduced from the August 2023 edition of U.S. EIA's Short-Term Energy Outlook. Available at ***https://www.eia.gov/outlooks/steo/*** *Retrieved August 21, 2023. EIA note: "Confidence interval derived from options market information for the five trading days ending August 3, 2023. Intervals not calculated for months with sparse trading in near-the-money options contracts."*

Figure 13 shows prices for WTI crude oil from a number of scenarios in AEO 2023. Oil prices rise slightly in the Reference case but remain below their 2022 peak of $101 per barrel. Prices differ substantially in the High and Low Oil Price scenarios, representing significant uncertainty about future oil prices. The 2022 price of oil in AEO 2023 ($101 per barrel) is about 44 percent greater than the price projected in AEO 2022, and it remains higher throughout the study period.

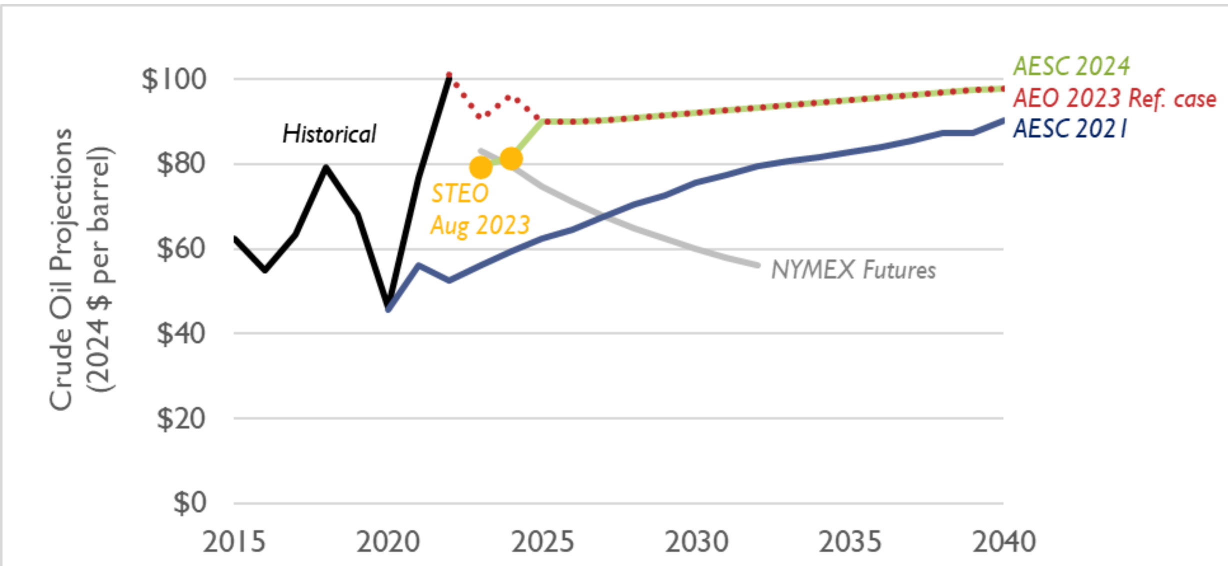
Figure 13. Oil prices projected in various AEO 2023 scenarios



Schedule MM-R1

For AESC 2024, we use STEO for the near-term crude oil prices (2023 and 2024) and AEO 2023 for the medium and long terms (2025 and all subsequent years) (see Figure 14). On average, the annual real rate of price increase for the 20-year period from 2024 to 2043 is about 1 percent per year. This forecast is not meant to predict the actual price in any given year, but rather to represent a mid-point expectation of fluctuating prices. The levelized price of crude oil over this 20-year time period is about 19 percent higher in AESC 2024 than in AESC 2021, primarily because the near-term prices are much higher as shown in Figure 14. This percentage increase in crude oil prices will be roughly reflected in that of other fuels.

Figure 14. Crude oil prices, historical, forecast, and AESC 2024



3.3. Forecast of fuel prices

For AESC 2024, starting points 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 33). SEDS represents a comprehensive compilation of the actual prices and consumption. Investigation of recent wood prices found delivered wood pellets to be in the range of $21 per MMBtu (before accounting for conversion efficiency).[60] Prices for cord wood and wood chips at the residential level are not readily available and vary widely in cost, heat value, and location.

Data in EIA's SEDS database is provided at the state level. We looked at 10 years (2012–2021) of historical data to determine if there are significant variations between the New England states. Except

60 New Hampshire Office of Strategic Initiatives. Last accessed September 15, 2023. "NH Fuel Prices." Available at: https://www.energy.nh.gov/energy-information/nh-fuel-prices.

Schedule MM-R1

for propane and wood, no consistent and significant state variations are apparent, and prices closely resemble national average prices (see Table 34).

Table 33. SEDS weighted average New England fuel prices from 2019–2021 by end-use sector (2024 $ per MMBtu)

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	20.5	19.5	17.4	25.7	16.8
Kerosene	23.1	23.2	17.2	-	-
LPG (Propane)	36.8	18.9	19.5	18.8	-
Residual fuel oil	-	14.4	14.8	10.1	12.2
Motor Gasoline	-	25.2	25.2	25.3	-
Wood	23.5	-	-	-	-
Wood & Waste	-	17.6	9.1	-	7.9

Table 34. Ratio of New England weighted average fuel price 2019–2021 to national weighted average fuel price

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	1.0	1.1	1.0	1.0	1.0
Kerosene	1.0	1.0	1.0	-	-
LPG (Propane)	1.4	1.1	1.5	0.8	-
Residual fuel oil	-	1.1	1.2	0.8	0.9
Motor Gasoline	-	1.0	1.0	1.0	-

AEO 2023 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.[61] This is the same mapping applied in the 2021 AESC Study.

AEO 2023 does not provide a forecast of New England regional prices for biofuel B5,B20, and B50 blends, as these blends represent a small portion of the New England market. These biofuel blends 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","B20", and "B50" represent products with a 5 percent, 20 percent, and 50 percent agricultural-derived component, respectively. They are 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,[62] more efficient

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[61] EIA Fuel oil definitions: U.S. EIA. "Glossary." Available at: https://www.eia.gov/tools/glossary/index.php?id=N.

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

Schedule MM-R1

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 U.S. Department of Energy Alternative Fuels Data Center (ASTM) D396, fuel oils for home heating and boiler applications may be blended with up to 5 percent biodiesel below the rack.[63, 64] Marketers are not required to disclose information on biodiesel content below these levels. Based on current data for New England, we project that B5 prices will be 4 percent below diesel prices in the future, B20 prices will be 16 percent below diesel prices, and B50 price will be 14 percent below diesel prices.[65]

The SEDS data show no differences in residential wood prices between the New England states. As the starting basis for wood prices, AESC 2024 uses recent data from New Hampshire, which is the same method as AESC 2021.[66] 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 2021 SEDS data, we adjusted those prices to represent the changes in oil prices since then. The AESC 2024 starting prices are shown in in Table 35.

Table 35. New England fuel prices in 2023 by end-use sector (2024 $ per MMBtu)

Fuel	Residential	Commercial	Industrial	Transportation	Electric
Distillate fuel oil	21.4	22.3	19.0	-	19.2
Kerosene	27.0	27.0	21.0	-	-
LPG (Propane)	40.7	22.8	24.9	22.6	-
Residual fuel oil	-	16.8	17.3	10.8	14.0
Motor Gasoline	-	28.9	28.9	28.9	-
Wood pellets	21.5	-	-	-	-
Cord wood	20.6	-	-	-	-

Prices in future years start with the base year prices as indicated above and then follow the AEO projections for New England starting in 2025 (Figure 14).[67] Prices in 2024 are interpolated to ensure a smooth transition between current prices and the AEO projections.

[63] Skierkiewicz, M. 2022. "Biodiesel Updates to UL Burner Standards." *Engineered Systems Magazine.* Available at: https://www.esmagazine.com/articles/102339-biodiesel-updates-to-ul-burner-standards.

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

[65] U.S. Department of Energy Alternative Fuels Data Center. "Fuel Prices: April 2023." Available at: https://www.afdc.energy.gov/fuels/prices.html.

[66] New Hampshire Office of Strategic Initiatives. Last accessed September 15, 2023. "NH Fuel Prices." Available at: https://www.energy.nh.gov/energy-information/nh-fuel-prices.

[67] In cases where there are noticeable differences between the SEDS and the AEO prices we rely on the SEDS prices, as these represent actual reported costs.

Schedule MM-R1

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.

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. The supply systems for these fuels 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.

Massachusetts emissions sublimits and the Clean Heat Standard

This section discusses the impact of Massachusetts' GHG emissions sublimits on avoided fuel oil costs. For more information on the rationale and methods used on this topic, see Section 4.8: *Embedded emissions regulations*. Table 31 compares avoided costs for fuel oils in the absence of any required biofuel blending, along with the avoided costs in each counterfactual, in line with the biofuel blending requirements implied by Massachusetts' sublimit requirements. Even with high levels of biofuel blending, avoided costs are largely similar, due to an assumption that the federal government subsidizes biofuel costs, to the degree that they are priced similar to fossil fuels.

We note that these costs should not be viewed in isolation. Because this methodology effectively embeds a GHG reduction policy (via an approximation of the forthcoming Clean Heat Standard) these incremental costs should be subtracted from the costs of GHG compliance. See the AESC 2024 *User Interface* and *Appendix G: Marginal Emission Rates* for calculating GHG impacts with and without these blending factors.

Table 36. Avoided costs of fuel oil and other fuels (2024 $ per MMBtu)

	Residential *Distillate fuel oil*	**Commercial** *Distillate fuel oil*	**Industrial** *Distillate fuel oil*	**Residential** *Propane*
No fuel oil blend	$30.60	$28.59	$27.52	$58.11
Counterfactual #1	$30.64	$28.63	$27.56	$58.18

Note: All values are 15-year levelized costs.

Schedule MM-R1

4. COMMON ELECTRIC ASSUMPTIONS

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

One of the main tasks of AESC 2024 is to estimate the electricity supply costs that would be avoided by reducing retail sales of electricity through energy efficiency initiatives or other emerging demand-side management (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 2: *Avoided Natural Gas Costs* and Chapter 3: *Fuel Oil and Other Fuel Costs*, respectively) modeling assumptions in AESC 2024 differ from those used in AESC 2021 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
- A new capacity accreditation framework reflecting ISO New England's Resource Capacity Accreditation (RCA) project that would accredit resources based on their modeled marginal reliability value

4.1. AESC 2024 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.[68] On average, prices in these two markets are typically close to one another, although there is

[68] For more information, see: ISO New England Inc. Internal Market Monitor. 2023. *2022 Annual Markets Report.* Available at: https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf.

Schedule MM-R1

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

AESC 2024 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 37 shows load and generation areas reported on in AESC 2024 and Table 38 details modeled load and generation areas. This is the same modeling topology as that used in AESC 2021. For AESC 2024, we use load-weighted averages to translate modeling zones into reporting zones. While some zones under each topology are close matches, other reporting comprise a number of different modeling zones. The percentages for weighting percentages are based on locations of pnodes

Schedule MM-R1

in specific states and modeling zones (see Table 39).[69] These weighting percentages are updated with 2022 nodal data that are similar, but not identical to, the weightings used in AESC 2021 (which was based on 2019 nodal data).

Table 37. Reporting zones in AESC 2024

	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 38. Modeled load zones in AESC 2024

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

[69] Pnode load factors for 2022 are available on the ISO New England website. ISO New England Inc. "Nodal Load Weights." *Energy, Load and Demand Reports.* Available at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/nodal-load-wgts.

Schedule MM-R1

Table 39. Translation between EnCompass modeling zones (vertical) and AESC 2024 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%	-	4%	-	-	-	-	-	-	-
NE Vermont	VT	-	15%	-	90%	-	-	-	-	-	-	-
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	-	-	12%	-	-	-	-	20%	77%	-	-
NE Rhode Island	RI	-	-	88%	-	-	-	-	6%	23%	-	-
NE Connecticut Northeast	CT	-	-	-	-	49%	-	98%	-	-	-	-
NE Connecticut Southwest	SWCT	-	-	-	-	33%	66%	-	-	-	-	-
NE Norwalk Stamford	NOR	-	-	-	-	17%	34%	-	-	-	-	-

Notes: Totals may not sum to 100 percent 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.[70]

[70] In this analysis, the Maritimes zone includes Versant Power's Maine Public District territory 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.

Schedule MM-R1

The Renewable Energy Market Outlook model

In addition to EnCompass, AESC 2024 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 buildouts, 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

AESC 2024 uses a spreadsheet model to develop FCM auction prices for power years from June 2024 through May 2028. Projections of prices during this period are based on recent FCA clearing prices, adjusted to reflect the load assumptions used in the relevant counterfactual (e.g., whether or not the counterfactual contains energy efficiency measures). 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 14 through FCA 17 and the assumption that the supply curve in future FCAs features similar slopes to FCA 17. 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.

Capacity accreditation and capacity requirements

The capacity market helps guide resource additions and retirements in New England, and it satisfies the region's resource adequacy objectives by procuring sufficient capacity resources. The constraint to ensure a reliable system is the Installed Capacity Requirement (ICR) and the value that each resource contributes toward the total capacity objective is each resource's accredited capacity. Beginning in June 2028, resources will be accredited based on their Qualified Marginal Reliability Impact Capacity (QMRIC), as proposed in ISO New England's Resource Capacity Accreditation (RCA) project. In AESC 2024, we calculate approximate ICR and QMRIC values based on the latest available ISO proposed methodologies and use these values in EnCompass to (1) ensure the model builds a resource mix that meets system reliability needs and (2) calculate capacity prices. Both capacity accreditation and capacity requirements are determined on a seasonal basis. For the near term through May 2028, before the RCA rules become effective, 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.*

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 reserve requirements, and it considers applicable costs when determining bids.

Day-Ahead Ancillary Services Initiative

ISO New England proposed a package of new day-ahead reserve products through its *Day-Ahead Ancillary Services* (DASI) proposal to ensure the day-ahead market clears a set of resources that can meet real-time needs and to increase incentives for resources to be available in real time (including by procuring fuel). 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 NEPOOL Participants Committee voted in favor of the proposal on August 3, and the proposal will now be filed with and reviewed by FERC. We recommend that any future impacts attributed to DASI be incorporated outside of the AESC study.

Schedule MM-R1

Modeling timescale

In EnCompass, REMO, and the FCM Model, we explicitly model 27 years from 2024 through 2050. In order to develop 30-year levelized avoided costs, AESC 2024 continues the trajectory of each avoided cost component through 2065.[71]

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

For avoided energy costs:

- We first model each year in EnCompass' capacity-expansion construct. In this construct, EnCompass optimizes to determine the most cost-effective capacity additions.[72] EnCompass is set to optimize over the full study period (2024–2050).[73] We run EnCompass at the resolution of a typical week. This means that EnCompass represents each year from 2024 to 2050 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.

- 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 2024 and 2050.

- 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).[74]

For avoided capacity costs:

- Program administrators can claim avoided capacity by either bidding capacity (cleared) into the capacity auctions, or by reducing loads through non-bid capacity (uncleared)

[71] In all cases, this involves extrapolating values through 2065. See *Appendix A: Usage Instructions* for the methodology used.

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

[73] In AESC 2021, we 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 at least one year [and possibly more years] before each auction). Earlier AESC studies typically used one-year optimization horizons, largely because of computing power limitations. When comparing resulting avoided costs in AESC 2024 with earlier studies that used different optimization periods, 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.

[74] 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.

(which then becomes phased in to load forecasts for subsequent capacity auctions). Hence, all avoided capacity is stated per kW of accredited capacity, and we identify the accredited capacity for efficiency resources based on their load profiles and resulting Marginal Reliability Impact (MRI). The effect of uncleared capacity for demand response will vary with the number days each summer or winter for which peak load is reduced and the number of years for which the load reduction continues (see *Appendix J: Guide to Calculating Avoided Costs for Cleared and Uncleared measures* 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 needs 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.[75] However, after the ISO's RCA proposal becomes effective in June 2028, performance during any high-risk hours (such as hours with lower renewable generation) will impact a resource's capacity value.
- 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 conditions will affect the accredited capacity demand for the region, an energy efficiency measure that reduces load throughout the year or in the days with higher loads and lower renewable generation should fully affect the load forecast. Load management that affects only a few summer or winter days would have a much smaller impact on the load forecast.

For DRIPE:

- Energy DRIPE is estimated as proportional to avoided energy cost. Thus, energy DRIPE can be applied to any level of disaggregated avoided energy cost.
- Capacity DRIPE is stated per kW of peak load reduction, for bid resources and for non-bid load reductions. Those values can be attributed to programs in the same manner as the avoided capacity costs, 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.

[75] 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 MA, Hartford CT, Providence RI, Portland ME, Manchester NH, Burlington VT, Springfield MA, and Worcester MA) and weighted by zonal loads.

Schedule MM-R1

Model calibration

Because one of the main outputs of AESC 2024 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 2020, 2021, and 2022 prices in the ISO New England's "SMD" dataset.[76] 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 2023, prices in future years are likely to substantially diverge from recent historical prices.

4.2. Modeling counterfactuals

The *AESC 2024 User Interface*, a set of standalone Excel workbooks, 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).[77] 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.

As with AESC 2021, AESC 2024 examines a series of counterfactuals. Each of these counterfactuals includes some DSM components and excludes others. 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. Table 40 details the DSM components included in each of the counterfactuals. Additional detail on the specifics behind the DSM components modeled in each counterfactual can be found in the subsequent sections of this chapter.

We note that this set of counterfactuals was developed via thorough discussion with the AESC 2024 Study Group, over multiple discussion dates and via a non-scientific survey.

For purposes of simplification and comparison, Counterfactual #1 is the counterfactual used for the discussion of many 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.

[76] "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 historical years can be found at on the ISO New England website. ISO New England Inc. "Zonal Information." *Energy, Load and Demand Reports.* Available at: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/zone-info.

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

Schedule MM-R1

Table 40. Counterfactual scenarios and sensitivities discussed for modeling in AESC 2024

	Counterfactual #1 "AESC Classic": Avoided costs for EE, ADM, and building electrification	**Counterfactual #2** Avoided costs for building electrification only	**Counterfactual #3** Avoided costs for EE only	**Counterfactual #4** Avoided costs for DR and BTM Storage only	**Counterfactual #5** All-in DERs	**Counterfactual #6** Avoided costs for BTM Storage only: Programmatic *and* non-programmatic measures	**Sensitivity #1** High Gas Price *(sensitivity on Counterfactual #1)*	**Sensitivity #2** Increased Clean Electricity *(sensitivity on Counterfactual #5)*
Energy efficiency	*No*	Yes	*No*	Yes	Yes	Yes	*No*	Yes
Building electrification	*No*	*No*	Yes	Yes	Yes	Yes	*No*	Yes
Demand response	*No*	Yes	Yes	*No*	Yes	Yes	*No*	Yes
BTM storage	*No*	Yes	Yes	*No*	Yes	*No (Programmatic and non-programmatic)*	*No*	Yes
Transportation electrification	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Distributed generation	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Likely to transition to winter peaking in study period?	*No*	*No*	Yes (likely transition by 2035)	Yes (likely transition by 2035)	Yes (likely transition by 2035)	Yes (likely transition by 2035)	*No*	Yes (likely transition by 2035)
RPS and other renewable policies	As described in Chapter 7	As described in Chapter 7	As described in Chapter 7	As described in Chapter 7	As described in Chapter 7	As described in Chapter 7	As described in Chapter 7	As described in Chapter 7, plus an IRCEP policy described in Chapter 12

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 2024 or any future year. Unless otherwise stated, 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). The "IRCEP" policy is described in detail in Chapter 12: Sensitivity Analysis.

Schedule MM-R1

4.3. New England system demand and energy components

Forecasts of annual peak demand and energy used in each of the AESC 2024 models are in large part based on the 50/50 values published by ISO New England in the 2023 *Forecast Report of Capacity, Energy, Loads and Transmission* (CELT) study.[78] However, our forecast includes modifications and enhancements to this forecast. Specifically, our load forecast covers the following components:

- Conventional load: 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 2023 CELT forecast, with adjustments. It also includes historical energy efficiency installed through 2023 but does not include any energy efficiency installed in 2024 or later years. It also does not include impacts from any of the categories discussed below.

- Energy efficiency: This is a projection of programmatic energy efficiency measures for 2024 and later years, for all New England states based on a combination of recent energy efficiency spending and savings, and data provided in ISO New England's 2023 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 programmatically linked heat pumps and water heating electrification measures, based on data provided in ISO New England's 2023 CELT forecast. It is used in counterfactuals that estimate avoided costs for measures *other than* building electrification.

- Demand response: This is a projection of the impacts from demand response measures, 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* demand response. Note that this projection includes separate projections for both programmatically linked and non-programmatic resources.

- Behind-the-meter storage: This is a projection of the impacts from behind-the-meter (BTM) energy storage, based on program data reported by states and utilities. It is used in counterfactuals that estimate avoided costs for measures *other than* active BTM storage. Note that this projection includes separate projections for both programmatically linked and non-programmatic resources.

- Transportation electrification: This is a projection of the impacts from light-, medium-, and heavy-duty electric vehicles, based on data provided in ISO New England's 2023 CELT forecast, with some minor modifications. It is used in all counterfactuals.

[78] 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.

- 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.

Conventional load

This section focuses on the conventional load (or "econometric") forecast for electricity demand. Generally speaking, this forecast comprises the impacts of "traditional" electric end uses (e.g., not transportation electrification or building electrification), as well as the installation of energy efficient measures no longer addressed by the energy efficiency load component (generally speaking, replacements for programmatic measures have expired, or measures that meet new codes and standards).

In May 2023, ISO New England released its newest electricity demand forecast, CELT 2023.[79] As in the CELT forecasts before it, in CELT 2023 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 over 30 years.

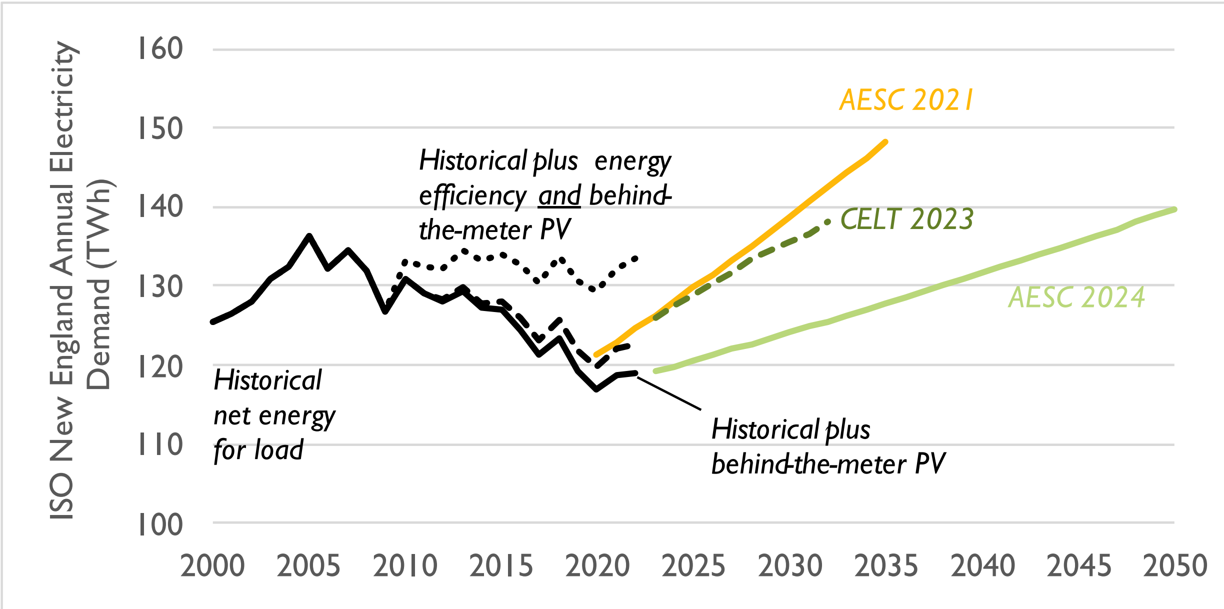
Study Group members identified that the projection estimated by ISO New England (a 0.9 percent compound annual growth rate for 2023–2032) seemed high relative to load growth in recent years (estimated to have been about 0.5 percent over the past 10 years, after accounting for impacts from energy efficiency and distributed solar measures). We note that the regression used by ISO New England is based on information from 1996 to 2022, with the primary driver of future load appearing to be gross state product. We also note that increases in gross state product in the 10 most recent years tend to be lower than in the late 1990s and early 2000s, indicating that this entire timespan may not be the best predictor of future load increases. Furthermore, the most recent 10 years span a period that had widespread deployment of energy efficiency measures even beyond those counted in the energy efficiency forecast, as a result of measures deployed via state federal codes and standards. Because future years are likely to continue to be impacted by savings resulting from these policies, and because it is convention by ISO New England for the conventional load forecast to incorporate the impacts of new measures that replace expiring efficient measures, it is likely that future load growth may continue to be lower than would be predicted based on a long timespan of data.

As a result, we develop a conventional load forecast based on the compound annual growth rate of historical electric load, with impacts from energy efficiency and behind-the-meter solar removed. This load growth rate is about 0.5 percent for New England as a whole but varies for each of the modeled regions. Figure 15 illustrates the New England-wide projection of annual electricity demand, relative to

[79] 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/2023/04/modeling_procedure_2023.docx .

recent historical forecasts, ISO New England's forecast as modeled in CELT 2023, and the forecast used in AESC 2021.

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



Notes: In both the CELT 2023 and AESC 2024 trajectories, all data points are decreased to reflect the energy efficiency installed through 2023 (see following section on "Programmatic Energy Efficiency"). No other impacts from energy efficiency, active demand management (demand response, behind-the-meter storage, or managed charging), building electrification, transportation electrification, or distributed solar are included. A similar operation is performed for the AESC 2021 trajectory, with the only energy efficiency savings being included from those measures which were installed through 2020.

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 2023 CELT study.[80] As a result, the hourly load shape for the conventional load component for January 1, 2024 (for example) is identical to the hourly load shape for this component for January 1, 2050. The primary difference will be that the quantities in 2050 will be larger, reflecting an overall increase in conventional load. These load shapes are based on weather data for 2002, a year identified by ISO as containing relatively average weather relative to other recent years.[81] While it is possible that load shapes may change over time, or change as a result of the changing

[80] In AESC 2024, we rely on the 2002-era load shapes hosted by ISO New England at https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data/ in order to achieve consistency between hourly load shapes and hourly renewable capacity factors. Past editions of AESC have used the hourly load shapes developed by ISO New England for the CELT 2023 forecast that can be found on the ISO New England website at https://www.iso-ne.com/static-assets/documents/2023/04/hrly_sa_fcst_eei2023.txt. We note that there are some differences between these two sets of load shapes, in part due to the fact that the dataset used in AESC 2024 is published at the state level, and the dataset used in previous studies is published at the modeling region level.

[81] For more on this assumption, see ISO New England's 2018 slide deck "Review of Assumptions Relating to ICR and Related Values – 2002 Load Shape," available at https://www.iso-ne.com/static-assets/documents/2018/04/a7_pspc_review_icr_2002_load_shape_04182018.pdf.

Schedule MM-R1

climate, 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.[82]

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).[83] 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. Throughout AESC 2024, we assume that all energy efficiency measures are programmatic, unless otherwise stated.

AESC 2024 bases some elements of its energy efficiency projection on the projection issued by ISO New England. This section consists of two subsections: the first describing ISO New England's overall approach and the second describing the modifications applied to this approach for purposes of AESC 2024.

ISO New England approach

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's development of an energy efficiency forecast for CELT 2023 varies in important ways, relative to the CELT 2020 forecast used as the basis for AESC 2021.[84] ISO New England's forecast is compiled as follows:

- First, ISO New England uses data from the latest completed FCA to establish a total level of energy efficiency in some future year. As of CELT 2023, the latest completed capacity auction was FCA 17, which denoted about 14 TWh of cumulative energy efficiency installed as of 2026. ISO New England then compares this to a "starting" level of energy efficiency installed as of 2010, subtracts the 2026 value from the 2010 value, and divides the result by the number of intervening years. This linear interpolation is performed

[82] Study Group members identified a desire to explore the impacts of choosing a different weather year on avoided costs. It was not possible to conduct this analysis under the AESC 2024 timeline and budget, but is a promising area for future analyses.

[83] 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.

[84] ISO New England. 2023. *Final 2023 Energy Efficiency Forecast*. Available at https://www.iso-ne.com/static-assets/documents/2023/04/eef2023_final_slides.pdf.

Schedule MM-R1

independently for each of the six New England states, and produces a single, unchanging quantity of annual installed energy efficiency for each year from 2011 through 2026 (697 GWh, New England-wide).[85] ISO New England notes that as the amount of energy efficiency that clears the capacity market will change in each year, so too will its estimate of historical energy efficiency. ISO New England also notes that this approach may underestimate the total amount of energy efficiency regionwide, as not all measures participate in the capacity market.[86]

- Second, ISO New England develops a projection of energy efficiency that will be installed in 2027 through 2032. Generally speaking, this estimate is produced for each state by dividing an annual energy by a production cost to produce annual incremental savings. The energy efficiency budgets are provided by state energy offices and tend to be roughly constant over time, in nominal dollar terms (meaning that they decrease over time when converted to 2024 dollars). Meanwhile, production costs vary in several ways. First, production costs are based on estimates from 2019–2021, which vary by sector and end use (e.g., Residential & Low Income HVAC, C&I Refrigeration).[87] These costs are then projected to grow both according to inflation and a 1.25 percent escalation rate. Costs also change over time in a third way, reflecting a shift away from some end-use types towards other end-use types (which is generally a shift away from cheaper end uses towards more expensive end uses). As a result, the production costs tend to increase substantially over the study period. For example, Massachusetts' Residential & Low Income production costs change from about $4,300 per MWh in 2027 to about $7,900 per MWh in 2032 (all values are in nominal dollars). This increase in production costs, paired with a decrease in program budgets (in real dollar terms), produces a steady decline in the annual incremental energy efficiency deployed.

- Third, ISO New England now incorporates embedded expiring measures.[88] This action is intended to capture situations where measures installed through energy efficiency programs expire, but are "naturally" replaced by like measures by consumers. ISO New England posits that this "like-for-like" replacement is otherwise being captured in the conventional load forecast and implements a set of steps to avoid double-counting. Practically speaking, to estimate a quantity of expiring measures, ISO New England compares the amount of energy efficiency that cleared in the most recent capacity auction with the amount of energy efficiency that cleared in the past auction with the most energy efficiency. Subtracting one value from the other yields a quantity of energy efficiency assumed to be expiring in each future year (roughly 800 GWh each year, New England-wide).

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[85] See Final 2023 Energy Efficiency Forecast, slide 24.

[86] Synapse observes that according to ISO New England's methodology, Massachusetts has 328 GWh installed in each year from 2011 through 2026. This is likely to be an overestimate for the earlier years, but for more recent years is likely an underestimate, given MassSave data (see https://www.masssavedata.com/) showing an average of 1,100 GWh installed in Massachusetts between 2019 and 2021.

[87] See *Final 2023 Energy Efficiency Forecast*, slides 9 through 15.

[88] See *Final 2023 Energy Efficiency Forecast*, slides 20 through 22.

As with other components of the 2023 CELT forecast, this forecast contains estimates of energy efficiency through 2032.

AESC 2024 approach

The approach for projecting energy efficiency in AESC 2024 builds on ISO New England's approach in a number of ways. Primarily, the Synapse Team implements modifications to bring the forecast more in line with the program administrators' plans for energy efficiency.

We implement modifications to ISO New England's approach as follows:

- Historical savings: Rather than basing historical savings on an extrapolation of energy efficiency cleared in recent auctions, our projection compiles savings data as reported by energy efficiency program administrators from 2010 through 2022. These data sources are compiled from a variety of sources, with the primary source being the Regional Energy Efficiency Database (REED) product published by Northeast Energy Efficiency Partnerships (NEEP).[89] Where necessary (e.g., for the most recent years' data and for situations where energy efficiency impacts must be isolated from programs containing kWh impacts from both energy efficiency and heat pump measures), this data is supplemented by information from program administrators' annual reports.

- Future budgets: Using the REED dataset as well as information submitted in program administrators' annual reports, we compile a set of recent budgets for energy efficiency programs (e.g., for 2022) for residential and C&I programs. These budgets are then held constant through 2050 in real-dollar terms.

- Future production costs: As in AESC 2021, we remove the 1.25 percent production-cost escalator assumed by ISO New England but assume the same switch in measure installations that yields a higher production cost over time.[90]

- Expiring measures: Using measure life data posted by Massachusetts program administrators for 2016 and 2021, we develop a set of expiration schedules for measure types (e.g., HVAC, process, hot water) and sectors (residential and C&I). We then apply these expiration schedules to all historical and future energy efficiency measure types in order to determine an estimate of the quantity of savings expected to be retiring in every year.[91] As described above, ISO New England assumes that as measures expire, they are replaced by similarly efficient measures within the conventional load forecast. As a result, the savings from these expiring measures must be removed from the energy efficiency component in order to avoid double-counting.

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[89] For more information on this dataset, see https://neep.org/emv/regional-energy-efficiency-database.

[90] Study Group members identified that escalations in production costs were already being sufficiently addressed via the change in measures being implemented, and that a supplementary production-cost escalator was unnecessary.

[91] Historical mixes of measure data are derived from a 2022 ISO New England report on this topic. ISO New England. *2023 Energy Efficiency Forecast Data Review and Verification: End Use Measure Data*. December 5, 2022. Available at https://www.iso-ne.com/static-assets/documents/2022/12/eefwg2023_meas_data.pdf.

- Special circumstances: In some situations, we supplement the above methodology with separate datasets. For example, as of October 2023, Rhode Island Energy is in the midst of assembling its energy efficiency plan for 2024–2026.[92] We assume the level of savings implied in this submitted plan for these years, and then switch to the above method for calculating savings in Rhode Island later years. Likewise, the state of Vermont assembles a long-term plan for energy efficiency for years 2024 to 2043.[93] We use this plan in place of the above methodology, with savings for 2043 held constant through 2050. In each of these cases, we apply the same assumptions as described above for expiring measures.

For AESC 2024, we must develop two different projections of energy efficiency through 2050. The first is an assumption on the level of energy efficiency that exists in 2023. This projection is used in Counterfactual #1 and Counterfactual #3. In this first projection, we deploy the above algorithm to estimate the measures that would be installed through 2023, and then do not implement any additional energy efficiency measures in 2024 and later years. However, during the 2024 to 2050 time period, measures expire, resulting in an overall diminishing in energy efficiency savings over time.

The second projection is based on a future where program administrators continue to implement energy efficiency throughout the study period. This second projection is used in Counterfactual #2, Counterfactual #4, Counterfactual #5, and Counterfactual #6. In this projection, we deploy the above algorithm for all years to estimate the amount of energy efficiency that would be installed (and would expire) in each year to estimate cumulative impacts from savings in each year.

We note that both of the above projections differ from the analogous projections of energy efficiency developed for previous AESC studies, which typically ignored expiring savings.

Figure 16 illustrates how these two energy efficiency projections compare with one another, and with the projection in ISO New England's CELT 2023 forecast. We note that the level of energy efficiency considered in both AESC 2024 projections is roughly 13 percent of total projected conventional load in the early 2020s (see Figure 15, above).

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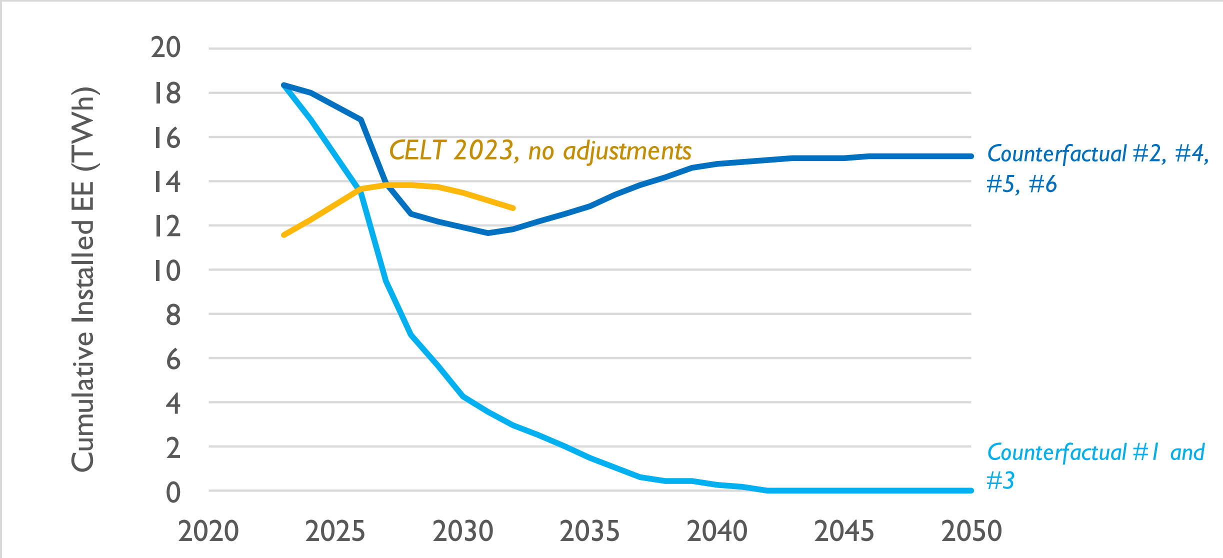
[92] 2024-2026 Energy Efficiency Three-Year Plan and Annual Energy Efficiency Plan for 2024, Rhode Island Public Utility Commission Docket No. 23-35-EE, Pre-Filed Direct Testimony of: Brett Feldman, Michael O'Brien Crayne, Mark Siegal, Toby Ast, and Spencer Lawrence. October 2, 2023. Available at https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-10/2335-RIE-Annual-ThreeYr-EEPlan_10-2-23-Bates.pdf.

[93] See EVT 2024-43 Demand Resource Plan proceeding, baseline modeling results Case No. 22-2954-INV and BED 2024-43 Demand Resource Plan proceeding, Plan A modeling results Case No. 22-2954-INV, provided to Synapse by VT DPS.

Schedule MM-R1

Figure 16. Projected cumulative regionwide energy efficiency impacts



For all modeled counterfactuals, the Synapse Team assumes the same hourly load shape for energy efficiency that is used for the conventional load component of the energy forecast. This effectively reduces the conventional load component in every hour by the fraction of modeled energy efficiency (in MWh) relative to the system demand. While different energy efficiency measures may have different load profiles in reality, this simplified approach is meant to approximate the implementation of a portfolio of energy efficiency measures. We determine peak impacts of energy efficiency and energy efficiency's contribution to the capacity requirement by estimating the peak hour for energy efficiency in each year, based on the annual regionwide energy efficiency amount and annual system demand impact.

Demand response

Demand response participates in ISO New England's FCM and serves as a peak demand resource. Demand response participation in the FCM has grown incrementally for several years. To forecast demand response impacts in future years, we rely on cleared capacity obligations through 2026. Then, to develop a forecast through 2050, we increase the 2026 quantity of demand response each year by the compound annual growth rate (CAGR) trend observed for capacity between 2018 and 2026. In FCA 17 (e.g., for commitment period 2026/2027), 623 MW of demand response capacity cleared the market and received a capacity supply obligation. This roughly doubles by 2050, growing to 1,130 MW. We assume all demand response that has cleared in the FCM so far is non-programmatic, as is all demand response projected to exist based on historical FCM values. As a result, this quantity of demand response is modeled in all counterfactuals.

In AESC 2021, based on direction from Study Group members from Massachusetts, we also assume an additional quantity of programmatic demand response. This quantity is based on the available-at-the-time draft planning numbers in Massachusetts. Under this assumption, we assume 162 MW of measures capable of demand response in 2020 and double that quantity by 2024. In AESC 2024, at the

Schedule MM-R1

recommendation of the Study Group, we update the assumed quantity of programmatic C&I demand response measures to assume a level of 120 MW in 2024 in Massachusetts and an annual increase of 7.5 percent per year through 2050. Based on the Study Group's recommendations, for programmatic residential demand response in Massachusetts, we adopt the AESC 2021 assumption of modeling a constant 54 MW in 2024 through 2050.

In AESC 2024, we also assume additional programmatic demand response based on direction from Study Group members from Rhode Island. Based on actual enrolled programmatic demand response capacities provided by the Study Group, we assume 79.7 MW of C&I demand response, and 5.6 MW of residential demand response. We adopt these values beginning in 2023 and hold them constant through 2050.

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 2024 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).[94]

Figure 17 shows the quantity of demand response modeled in AESC 2024. One series, labelled "Non-programmatic and historical programmatic" includes all non-programmatic demand response (i.e., that which cleared in the capacity market, and is projected into the future based on historical capacity results) and all programmatic demand response assumed to have been installed through 2023. The second series, "Future programmatic" includes all other demand response measures that are projected to be installed by the program administrators. The total quantity of demand response modeled in AESC 2024 is similar to the quantity modeled in AESC 2021. As in AESC 2021, we assumed the majority of demand response measures to be non-programmatic and thus modeled them the same way in every counterfactual. Programmatic demand response is included in Counterfactuals #2, #3, #5, and #6. For modeling purposes, demand response capacities outside of those cleared in the FCM capacities are grossed up by 8 percent to reflect a conversion between retail MW and wholesale MW.[95]

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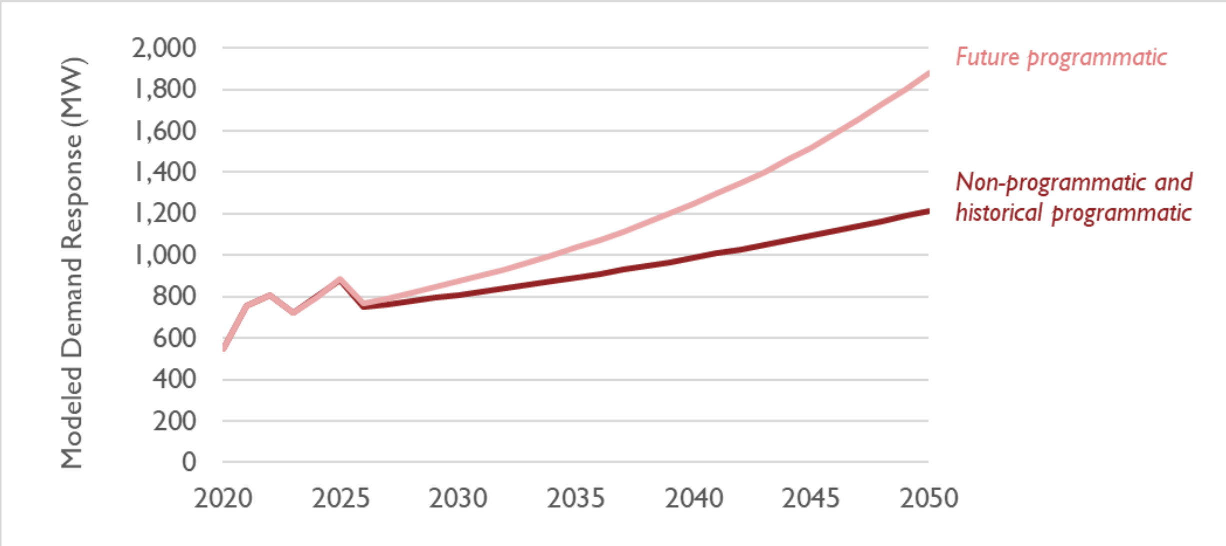
[94] These are the same values assumed in AESC 2021, without adjustments to dollar years (reflecting their nature as high-level assumptions).

[95] We assume that capacities cleared in the FCM, and projected future capacity based on these quantities, are already reported in wholesale terms.

Schedule MM-R1

Figure 17. Demand response forecast for New England



Note: Values shown are for retail MW, rather than wholesale MW.

Another type of demand response is flexible load, such as managed charging for electric vehicles or programs that compensate owners of electric water heaters to pre-heat their water several hours ahead of expected use. However, AESC 2024 does not consider any quantity of managed charging or other flexible load resources.

Behind-the-meter storage

There is currently no regional projection of BTM storage for New England. Furthermore, data availability on existing BTM installations vary by state, and by administrator. To establish a baseline of existing and projected BTM storage installation in New England, we assemble data and projections from policy mandates and incentives for BTM storage for every state and New England. We then aggregate these projections to forecast total BTM storage capacity through 2050.

- Connecticut: On January 1, 2022, the Connecticut Public Utilities Regulatory Authority (PURA) launched the Energy Storage Solutions Program.[96] This program is administered by Connecticut Green Bank, Eversource, and United Illuminating for both residential and C&I customers, and it is expected to run at least through December 31, 2030. The program has a goal of reaching 580 MW of storage by 2030.[97] As of August 18, 2023, this program had completed 0.71 MW of BTM storage, with an additional 77 MW of

[96] Energy Storage Solutions Administrators. "Energy Storage Solutions." Available at: https://energystoragect.com/.

[97] Energy Toolbase Software Inc. 2021. "Connecticut Makes Strides Towards 1,000 MW Statewide Goal with Public Utilities Regulatory Authority (PURA) Approval of New Energy Storage Incentive." Available at: https://www.energytoolbase.com/newsroom/blog/connecticut-pura-approves-new-energy-storage-incentive.

Schedule MM-R1

approved projects that are not yet completed.[98] Per the Study Group's recommendation, we assume this 580 MW is installed by 2030 and is a programmatic resource.

Eversource also administers the Connected Solutions program in Connecticut. This program provides residential customers incentives for supplying their own batteries.[99] 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 between June and September. This program will be phasing out in Connecticut due to the new Energy Storage Solutions offering and will not accept new customers after December 1, 2023.

- Maine: Efficiency Maine Trust (EMT) currently administers the Energy Storage System Program, which offers performance-based incentives of $200 per kW of reduced grid-supplied load for energy storage systems installed by non-residential, demand-metered customers.[100]

  In addition, in June 2021, Maine passed LD 528, which set energy storage goals for Maine of 300 MW by 2025 and 400 MW by 2030.[101] These goals are not modeled as a requirement in AESC 2024.

  Finally, in May 2022, Maine passed LD 2030, which provides a refund of sales and use tax to customers who purchase a qualifying battery energy storage system.[102] This reimbursement will only apply to systems with a minimum capacity of 50 MW, purchased between January 1, 2023, and December 31, 2025. Given the large minimum capacity constraint, we do not think that this program is pertinent to BTM storage.

- Massachusetts: Through the Solar Massachusetts Renewable Target (SMART) program, participants can receive an incentive for pairing an Energy Storage Adder to their solar project. As of October 2023, this program had approved about 34 MW of BTM storage in Massachusetts.[103] At the recommendation of the Study Group, we model the SMART

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[98] Energy Storage Solutions Administrators. "Energy Storage Solutions Performance Report." Available at: https://energystoragect.com/ess-performance-report/.

[99] Eversource. Last accessed August 18, 2023. "Demand Response for Home Battery Storage." *Demand Response.* Available at: https://www.eversource.com/content/residential/save-money-energy/energy-efficiency-programs/demand-response/battery-storage-demand-response.

[100] Efficiency Maine. "Energy Storage System Projects." Available at: https://www.efficiencymaine.com/energy-storage-system-projects/.

[101] State of Maine Governor's Energy Office. "Energy Storage." Available at: https://www.maine.gov/energy/initiatives/renewable-energy/energy-storage.

[102] State of Maine Governor's Energy Office. 2023. *Evaluation of the role of existing and potential tax incentives in achieving Maine's energy storage policy goals*. Submitted by the Governor's Energy Office to the Joint Standing Committee on Energy, Utilities and Technology, Pursuant to LD 2030: An Act to Provide for Reimbursement of the Sales Tax Paid on Certain Battery Energy Storage Systems. Available at: https://legislature.maine.gov/doc/10084.

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

program as being 25 percent programmatic through 2034, and 15 percent programmatic from 2035 on.

Additionally, the SMART program also offers storage for "standalone solar" projects, labeled in the SMART program separately from BTM projects. We include these projects in our model as well to ensure our forecast accounts for small, standalone storage projects, as our forecast aims to capture all storage. As of October 2023, the SMART program had approved about 279 MW of standalone storage.

Second, Program Administrators deploy the Connected Solutions program through Mass Save, which provides residential customers an incentive of $275 per average kW used from their demand response resources over a two- to three-hour period for supplying their own batteries.[104, 105] Massachusetts requires utilities to report on their energy storage installations annually.[106] These target reports, in addition to reporting on SMART program installations, contain entries labeled "MA – Energy Efficiency/DR Program." At the guidance of the Study Group, we assume these installations to be associated with the Connected Solutions program.

Additionally, utility target reports contain entries labeled "MA – DOER/ MassCEC Funded Projects." We assume these projects are related to the Massachusetts Clean Energy Center's (MassCEC) Advancing Commonwealth Energy Storage (ACES) program.[107] This program consists of a pilot of 26 energy storage demonstration projects, running from 2017–2024.

Third, in March 2023, Cape Light Compact received approval to launch its Cape & Vineyard Electrification Offering (CVEO) program.[108] This program will begin with a pilot to serve 100 residential low- and moderate-income customers, 25 of which will receive BTM storage systems.

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104 MassSave. Last accessed August 22, 2023. "Use Your Battery Storage Device to Make the Grid More Sustainable." Available at https://www.masssave.com/saving/residential-rebates/connectedsolutions-batteries.

105 During AESC 2021, 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. 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, and Mass Save. 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.

106 Mass.gov. Last accessed August 24, 2023. "ESI Goals & Storage Target." Available at: https://www.mass.gov/info-details/esi-goals-storage-target.

107 Massachusetts Clean Energy Council. "Advancing Commonwealth Energy Storage (ACES)." Available at https://www.masscec.com/program/advancing-commonwealth-energy-storage-aces.

108 Olinsky-Paul, T., Epstein, G. 2023. *Innovative Massachusetts Low-Income Battery Pilot Finally Wins Approval (For Now…)*. Clean Energy Group. Available at: https://www.cleanegroup.org/innovative-massachusetts-low-income-battery-pilot-finally-wins-approval-for-now/.

Schedule MM-R1

Finally, the Clean Peak Standard (CPS), effective June 2020, may also serve as an incentive for BTM storage in the state. Qualified resources under the CPS include new renewable resources that also meet eligibility under Massachusetts' Class I and Class II RPS program.[109] 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. 2019 modeling published by Massachusetts Department of Energy Resources described the estimated benefits under the CPS, which are projected to reach over 120,000 metric tons by 2030.[110] 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.[111] This is substantially larger than the Commonwealth's current storage target of 500 MW in 2025, and about 1,500 to 1,800 MW larger than the quantity of BTM storage assumed to exist in 2030 in any counterfactual, as a result of the other programs described above.[112] Because of a lack of information on CPS requirements for each modeled year in AESC, we do not explicitly model this program.

- New Hampshire: In 2019, the New Hampshire Public Utilities Commission approved a BTM Battery Storage Pilot Program for Liberty Utilities' customers.[113] The pilot contains two phases, the first of which was completed in 2022 and provided 96 participants with a total of 192 batteries, equivalent to roughly 0.96 MW of storage.[114] Phase 2, if approved, combined with Phase 1 will put a total of 2.5 MW of BTM storage in New Hampshire.

- Rhode Island: As in Massachusetts and Connecticut, Rhode Island Energy administers the Connected Solutions program which provides residential customers incentives of

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

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

[111] 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

[112] 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." Available at https://www.mass.gov/info-details/esi-goals-storage-target.

[113] Gheorghiu, I. 2019. *Designing Liberty Utilities' New Hampshire residential storage program*. Utility Dive. Available at: https://www.utilitydive.com/news/designing-liberty-utilities-new-hampshire-residential-storage-program/548940/.

[114] Guidehouse. November 2022. *Battery Storage Pilot Program: Interim Evaluation Report*. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2022-11-29_GSEC_INTERIM-EVALUATION-REPORT.PDF.

Liberty. Accessed August 22, 2023. *Battery Storage*. Available at: https://new-hampshire.libertyutilities.com/bath/residential/smart-energy-use/electric/battery-storage.html#:~:text=The%20battery%20storage%20program%20is,called%20the%20Tesla%20Powerwall%202.

Schedule MM-R1

$400 per average kW used from their demand response resources over a two- to three-hour period between June and September for supplying their own batteries.[115] At the guidance of Study Group members from Rhode Island, we assume a forecast of 16 MW of BTM storage in 2025, 76 MW in 2035, and 217 MW in 2050.

Second, the Rhode Island Renewable Energy Fund (REF) Small-Scale Solar Program offers a flat $2,000 per project for energy storage system adders to residential solar projects.[116] Program data is not currently available.

- Vermont: In Vermont, Green Mountain Power (GMP) offers two residential battery storage programs: the Bring Your Own Device (BYOD) Program, and the Tesla Powerwall Program.[117] The BYOD Program has incentivized between 13 and 14 MW of BTM storage installed in the state in 2019.[118] Both programs currently each have a cap of 500 new customers per year, or the equivalent of about 5 MW of storage per year for the next 15 years (e.g., until 2035), and are projected to meet that cap each year for the next 15 years. In 2023, GMP requested to lift this cap due to high customer demand for the programs.[119]

The storage forecast from 2020 through 2050 for the entire New England region is shown in Figure 18. We model any resources marked as "Unclear" (where it is unknown whether the resource is programmatic or non-programmatic) as non-programmatic, and we assume virtually all future incremental BTM storage to be non-programmatic.

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[115] Rhode Island Energy. Accessed August 14, 2023. *Battery Program*. Available at: https://www.rienergy.com/RI-Home/ConnectedSolutions/BatteryProgram.

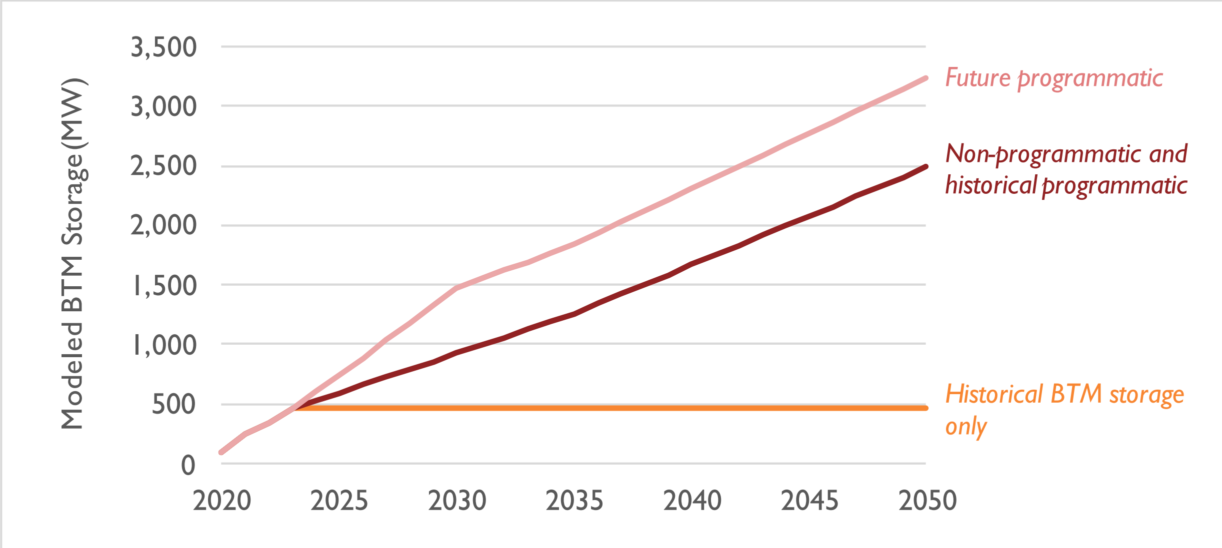
[116] State of Rhode Island Office of Energy Resources. Accessed August 22, 2023. *State and Federal Energy Incentives*. Available at: https://energy.ri.gov/incentives.

[117] Green Mountain Power. Accessed August 22, 2023. *Home Energy Storage*. Available at: https://greenmountainpower.com/rebates-programs/home-energy-storage/.

[118] 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/.

[119] Green Mountain Power. April 26, 2023. "GMP Requests Removal of Cap on Powerwall and BYOD Home Battery Programs to Expand Customer Access to Cost-Effective Backup Power". Available at: https://greenmountainpower.com/news/gmp-requests-removal-of-cap-on-powerwall-and-byod-home-battery-programs/.

Figure 18. BTM storage forecast for New England



Our modeling applies program-specific battery dispatch profiles for BTM storage wherever possible. For programs where a specific battery dispatch profile is not described, we assume that storage will dispatch according to the CPS seasonal peak periods, in line with our methodology in AESC 2021. Under the CPS, systems may only get CPS credits for discharging within these hours, so we assume each system is limited to discharging once per day (or 365 cycles per year). Table 41 describes the dispatch profile we apply to each program.

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.[120] We calculate MWh from capacity assuming a 2-hour duration. For modeling purposes, BTM storage capacities are grossed up by 8 percent to reflect a conversion between retail MW and wholesale MW.

Given the lack of data on BTM storage projections for each program, it is sometimes 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 2024 Sponsors, and what portion may be deployed regardless of actions taken by the AESC 2024 Sponsors. Table 41 describes what category each of the above programs appears to fall into. For the purposes of AESC 2024, we assume that only policies marked as "Programmatic" are programmatic; we model all other policies in all counterfactuals. Note that these "Non-programmatic" resources make up the vast majority of all BTM storage resources; constituting over 99 percent of BTM storage capacity in each modeled year.

[120] 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.

Schedule MM-R1

Table 41. Behind-the-meter storage categorization

State	Policy	Categorization	AESC 2024 Methodology	Assumed AESC 2024 Dispatch Profile
CT	Connected Solutions	**Programmatic**. Program entirely administered by Eversource; no data available.	Assuming 0 MW, due to no available data. Program not accepting new participants after 12/1/2023.	None (modeling program as 0 MW).
CT	Energy Storage Solutions	**Programmatic.** Program administered by Connecticut Green Bank, Eversource, and United Illuminating; partial 2022–2023 data available.	2022 and 2023 values are based on actual program data, as of 8/18/2023. We assume program grows linearly to meet the goal of 580 MW by 2030.	Winter (November 1 through March 31) 3 p.m. to 9 p.m., Summer (June 1 through September 30) 3 p.m. to 9 p.m.[121]
ME	Energy Storage System Program	**Non-Programmatic.** Program administered by Efficiency Maine Trust (EMT); no data available.	Program-specific data unavailable. Statewide actual storage data (2019-2022) used from Governor's Energy Office of Maine. Numbers in 2023 and after are held constant at 2 MW.	Proposing to adopt CPS dispatch profile.
MA	SMART Program	**Partially Programmatic.** Project may overlap with other Massachusetts BTM storage policies. Measures assumed to be counted in the CPS program. BTM projects are assumed to be 25% programmatic and 75% non-programmatic through 2034, and 15% programmatic and 85% non-programmatic from 2035 on. Standalone storage projects are assumed to be non-programmatic.	2018–2023 values are based on actual program data, available through 10/3/2023. Numbers in 2035 and 2050 are based on MA statewide targets, as well as forecasts provided by the Study Group.	Proposing to adopt CPS dispatch profile.
MA	Connected Solutions	**Programmatic.** This refers to data entries in utility target reports labeled "MA – Energy Efficiency/ DR Program."	2019–2022 values are based on MA 2022 ES Target Report data. Numbers in 2023–2025 assume continued average growth as calculated with existing data. Numbers in 2026 and after are held constant at 9 MW.	Proposing to adopt CPS dispatch profile.
MA	Other	**Unclear.** This refers to data entries in utility target reports that are not associated with SMART or Connected Solutions programs, including "MA–DOER/ MassCEC Funded Projects" and "Other" projects.	2019–2022 values are based on MA 2022 ES Target Report data. Numbers in 2023–2025 assume continued average growth as calculated with existing data. Numbers in 2026 and after are held constant at 10 MW.	Proposing to adopt CPS dispatch profile.
MA	Cape & Vineyard Electrification Offering (CVEO)	**Programmatic**. Program entirely administered by Cape Light Compact; no data available.	2023–2024 values are based on approved pilot program design. Numbers in 2025 and after are held constant at 0.15 MW.	Proposing to adopt CPS dispatch profile.
MA	Clean Peak Standard (CPS)	**Unclear.** Project may overlap with other Massachusetts BTM storage policies.	We d not model additional CPS resources explicitly and are assuming it is otherwise met through other programs.	Winter (December 1 through February 28) 4 p.m. to 8 p.m., Spring (March 1 through May 14) 5 p.m. to 9

[121] Eversource. Accessed August 18, 2023. *Connecticut Home Battery Storage Options*. Available at: https://www.eversource.com/content/residential/save-money-energy/clean-energy-options/home-battery-storage.

Schedule MM-R1

State	Policy	Categorization	AESC 2024 Methodology	Assumed AESC 2024 Dispatch Profile
				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.[122]
NH	Battery Storage Pilot Program	**Programmatic**. Program entirely administered by Liberty Utilities.	2020–2022 values are based on program evaluation data. 2023–2025 values assume Phase 2 of the pilot will be approved. Numbers in 2026 and after are held constant at 2.5 MW.	Winter (November 1 through April 30) 3 p.m. to 8 p.m., Summer (May 1 through October 31) 3 p.m. to 8 p.m.[123]
RI	Connected Solutions	**Programmatic**. Program entirely administered by Rhode Island Energy.	Values in 2025, 2035, and 2050 are based on forecasts from Rhode Island Energy, assuming linear growth between those years.	Summer (June 1 through September 30) 3 p.m. to 8 p.m., two to three hours event, for C&I.[124]
RI	Renewable Energy Fund (REF) Small-Scale Solar Program	**Non-Programmatic**. Program administered by Rhode Island Commerce.	Assuming 0 MW, due to no available data.	None (modeling program as 0 MW).
VT	BYOD Program	**Non-Programmatic**. Program entirely administered by Green Mountain Power (GMP) (not a program administrator).	Assuming 5 MW of annual growth, based on maximum allowed annual participation and GMP press statements that program waitlists are full multiple years out. Reaches 75 MW in 2035.	Proposing to adopt CPS dispatch profile.
VT	Tesla Powerwall Program	**Non-Programmatic.** Program entirely administered by GMP (not a program administrator).	Assuming 5 MW of annual growth, based on maximum allowed annual participation and GMP press statements that program waitlists are full multiple years out. Reaches 88 MW in 2035.	Proposing to adopt CPS dispatch profile.

Table 42 shows the total cumulative BTM storage projected to be installed in each state in New England, in 2025, 2035, and 2050. The modeled quantity of BTM storage in 2035 (inclusive of both programmatic and non- programmatic resources) is about three times larger than the 2035 quantity modeled in AESC 2021. Non-programmatic BTM storage resources are modeled in all counterfactuals except Counterfactual #6. Programmatic BTM storage resources are only modeled in Counterfactual #2, #3, and #5. In Counterfactual #6, we do not model any new BTM storage (programmatic or non-programmatic) installed in 2024 or any later years.

122 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.

123 Liberty. Accessed August 22, 2023. *Battery Storage*. Available at: https://new-hampshire.libertyutilities.com/bath/residential/smart-energy-use/electric/battery-storage.html#:~:text=The%20battery%20storage%20program%20is,called%20the%20Tesla%20Powerwall%202.

124 RI Connected Solutions dispatch profile provided by Rhode Island Energy via email on October 23, 2023.

Schedule MM-R1

Table 42. Modeled quantites of behind-the-meter storage (MW)

State	2025	2035	2050
Connecticut	218	580	580
Maine	2	2	2
Massachusetts	443	1,016	2,266
New Hampshire	3	3	3
Rhode Island	16	76	217
Vermont	63	163	163
Total	**744**	**1,839**	**3,230**
Fraction of total MW attributable to incremental programmatic BTM storage resources	**21%**	**32%**	**23%**

Note: This table includes capacity from all programs, including both programmatic and non-programmatic BTM storage. Quantities are reported in retail terms, rather than in wholesale terms.

Building electrification

Measures related to building electrification are projected to be a significant source of load growth over the study period, in certain counterfactuals. Primary examples of such measures include heat pumps for space and water heating. ISO New England developed a forecast of residential and commercial heat pump load as part of its CELT 2023 report.[125] ISO New England developed this forecast in collaboration with regional stakeholders who provided information about heat pump programs, incentives, and policy targets across the New England states. Broadly speaking, heat pump adoption was modeled by state, by sector (residential and commercial), by end use (HVAC vs. water heating), by heat pump type (partial vs. whole building), by existing fuel system (gas, fuel oil, etc.), and by electrification technology (e.g., air- vs. ground-source heat pump). The modeling extends to 2050, although the report only provides data on energy consumption and peak load from 2023 through 2032.

Generally speaking, ISO New England bases its projections around residential heat pump adoption levels of about 15 percent in 2030 and 85 percent in 2050, and commercial heat pump adoption levels of about 15 percent in 2030 and 80 percent in 2050.

Relative to other load forecast components (e.g., energy efficiency and transportation electrification), ISO New England has published little granular data on its building electrification forecast, aside from state-specific projections. The ISO has published no data on hourly demand impacts. On October 23, ISO New England shared some more detailed information with Synapse (including adoption trajectories and associated demand by state, sector, and heating type from 2023 through 2032), but we have not yet used this data to inform AESC projections because this data was not available until October 23. Instead, Synapse's projections are currently based on the publicly available version of ISO New England's modeling.

[125] ISO New England. *Final 2023 Heating Electrification Forecast*. April 28, 2023. Available at https://www.iso-ne.com/static-assets/documents/2023/04/heatFx2023_final.pdf.

Schedule MM-R1

Synapse first project the number of heat pumps added in each state from 2023 to 2050, primarily relying on the adoption trajectories published in the 2023 CELT forecast—as mentioned above.[126] We divide annual heat pump additions into four categories: residential space heating, residential water heating, commercial space heating, and commercial water heating. We then subdivide space heating into partial and whole-home systems using technology breakdowns provided by ISO New England for 2032 and 2050 and calculating values for the intermediate years through linear interpolation.[127]

Synapse translates these stock values into annual electricity demand using load and coefficient of performance (COP) assumptions. To relate COP to temperature, we apply a regression analysis (separately for residential space heating and commercial space heating, to create COP trendlines) based on data from ISO New England.[128] We apply load assumptions based on end-use data for natural gas space heating measures from NREL's ResStock and ComStock for Massachusetts.[129] Consistent with ISO New England's assumptions in the 2023 CELT forecast, we assume that partial systems have zero electricity load when temperatures drop below 20 degrees Fahrenheit; we calculate the number of hours when this is the case using the weather data described below. Also consistent with the 2023 CELT forecast, we assume that whole-home systems switch from heat pump heating to electric resistance heating when temperatures drop below 5 degrees Fahrenheit. Finally, we assume a retail to wholesale conversion factor of 6 percent.

Figure 19 shows the resulting electrification load in each year for New England as a whole. The Synapse estimate is 17 percent higher than ISO New England's in 2025 and nearly identical (0.1 percent higher) in 2032, the last year that ISO New England provides energy data. Differences are due to a combination of lower commercial heating load projections and higher residential load projections, as compared to ISO New England's.

For the purposes of AESC 2024, we assume all building electrification impacts are programmatic.[130]

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[126] Id., at slides 21, 25, 28, and 31. Note that based on Study Group feedback, we modified the trajectory for heat pump adoption in Massachusetts by relying on near-term projections of heat-pump builds described in the high end of the ID1 and ID2 projections as summarized in the following documents: https://ma-eeac.org/wp-content/uploads/MA-EEAC-Workshop-4-Residential-Summary-FINAL.pdf and https://ma-eeac.org/wp-content/uploads/MA-EEAC-Workshop-2-IES-Summary_FINAL.pdf. We received feedback from Study Group members representing program administrators in Rhode Island, Vermont, and Maine, but through discussion decided to not edit the adoption trajectories for these states or any other states save Massachusetts.

[127] Id., at slide 36 and 37.

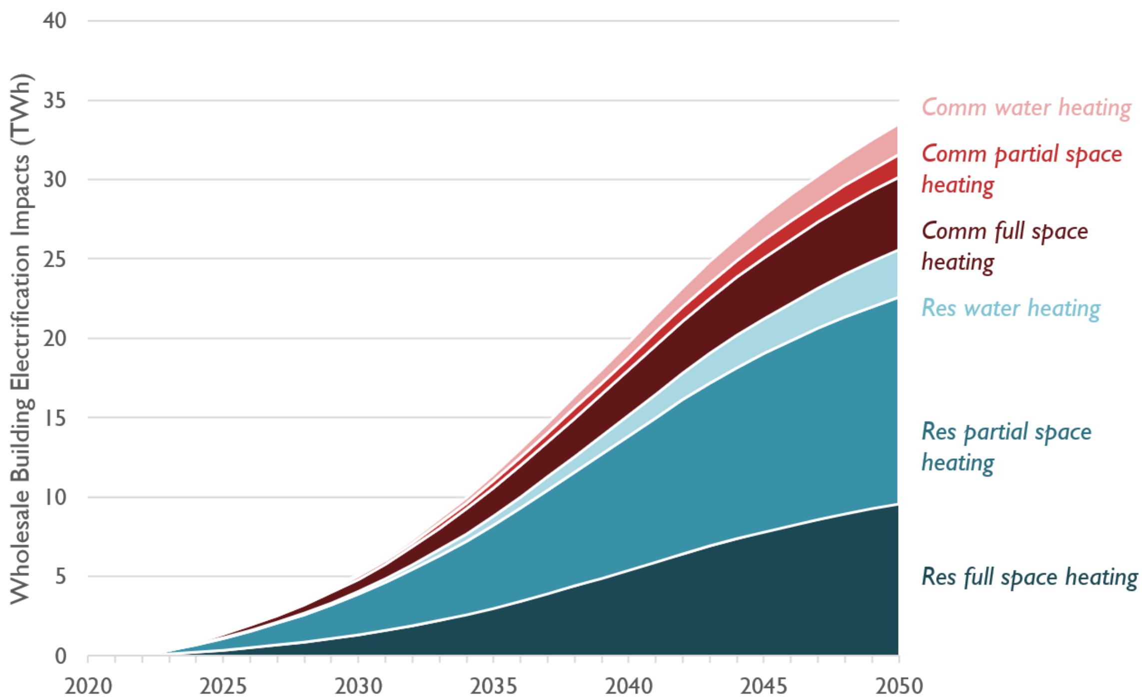
[128] Id., at slide 36 and 37.

[129] See https://resstock.nrel.gov/ and https://comstock.nrel.gov/. We do not rely on ResStock and ComStock's load shapes for space-heating heat pumps, as we understand that these load shapes may be inappropriate to use due to low sampling and dated COPs. Furthermore, it is possible that the heat pump load shapes do not accurately account for pre-heating activities by users. As a result, we rely on the heating shape implied by natural gas furnaces, and we derive hourly space heating heat pump operation based on this heating demand. We rely on ResStock and ComStock for heat pump water heating operation due to the relative lack of data available on these technologies, their relatively low impact on total and peak loads, and their relative independence of electricity demand to outside temperatures.

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

Schedule MM-R1

Figure 19. Modeled incremental building electrification load



To forecast hourly building electrification for each end use in each state through 2050, we combine the annual building electrification energy demand from 2023 to 2050 and hourly load profiles in EnCompass.

Counterfactuals #1 and #2 only include the building electrification installed through 2023; all other future building electrification measures are not included. In contrast, the full set of building electrification measures projected to be installed through 2050 are modeled in Counterfactuals #3, #4, #5, and #6.

Transportation electrification

Over the study period of AESC 2024 (e.g., through 2050), vehicle electrification is projected to increase demand for electricity. In CELT 2023, ISO New England developed a forecast for electric vehicle electricity consumption.[131] The CELT forecast is based on information supplied by state policies and state agencies, federal rulemaking, and other sources. CELT 2023 includes two forecasts—a "Full Electrification" adoption scenario and a "CELT 2023" adoption scenario. The ISO identifies the first scenario ("Full Electrification") as being for informational purposes only and provides less information for it than the "CELT 2023 scenario." Both scenarios are relatively similar, with electric vehicles

[131] For more on ISO New England's CELT 2023 transportation electrification forecast, see ISO New England. *Final 2023 Transportation Electrification Forecast*. April 28, 2023. Available at https://www.iso-ne.com/static-assets/documents/2023/04/transfx2023_final.pdf.

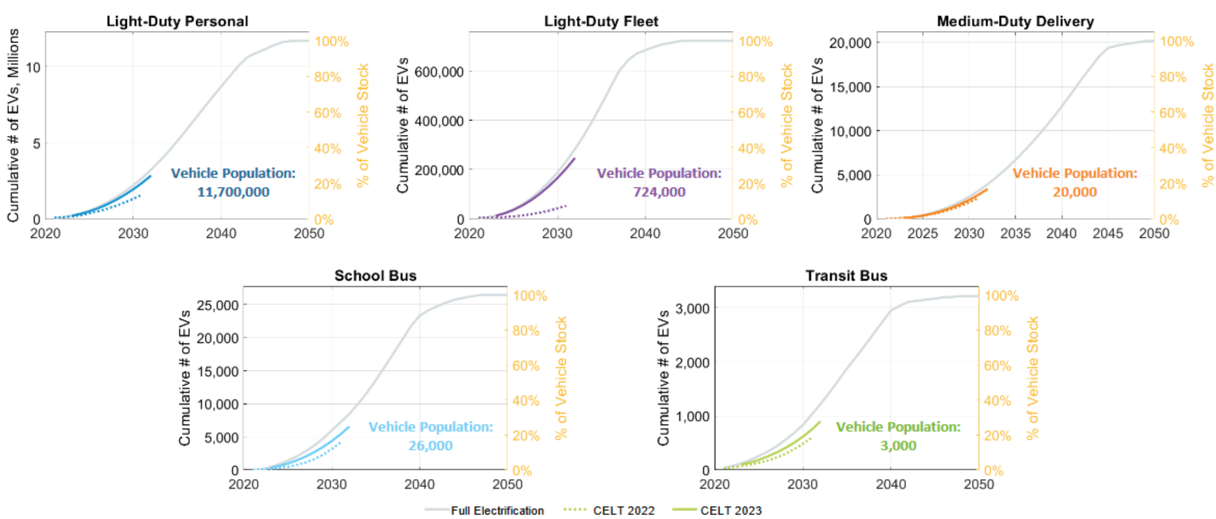
Schedule MM-R1

representing about 20 to 30 percent of vehicles on the road ("stock") by the mid-2030s, and with all or almost all vehicles being electric by the late 2040s (see Figure 20).

In its projections, ISO New England develops state-specific projections of electric vehicle stock and associated electricity demand. These projections are developed for five different classifications of vehicles: (1) light-duty personal vehicles, (2) light-duty fleet vehicles, (3) medium-duty delivery vehicles, (4) school buses, and (5) transit buses. We note that this projection does not include all vehicle types (for example, other medium-duty vehicles, heavy-duty vehicles, and non- and off-road vehicles are not included) but does address the majority of vehicles driven in New England (in terms of number of vehicles, fuel consumption, and emissions impacts). ISO New England's projection considers daily charging for each vehicle type by month; variations in charging profiles by month, vehicle type, and day-of-week; and variations in vehicle-miles traveled and electricity consumption by vehicle type.

Using data posted publicly by ISO New England, Synapse estimates a projection of annual load requirements for electrified vehicles and hourly load shapes. Figure 20 shows forecasts both for CELT 2023 (used in AESC 2024) as well as ISO New England's more ambitious "Full Electrification" case. CELT 2023 provides data for load projections through 2032 only; these projections are extrapolated for each state and vehicle type through 2050, based on the shape of the "Full Electrification" case through 2050.

Figure 20. ISO New England's 2023 forecast for transportation electrification



Notes: The grey line denotes the "Full Electrification" trajectory. The solid non-grey line indicates the trajectory used by ISO New England in CELT 2023. ISO New England also provides state-specific detail, which is used in AESC 2024's estimate for transportation load.

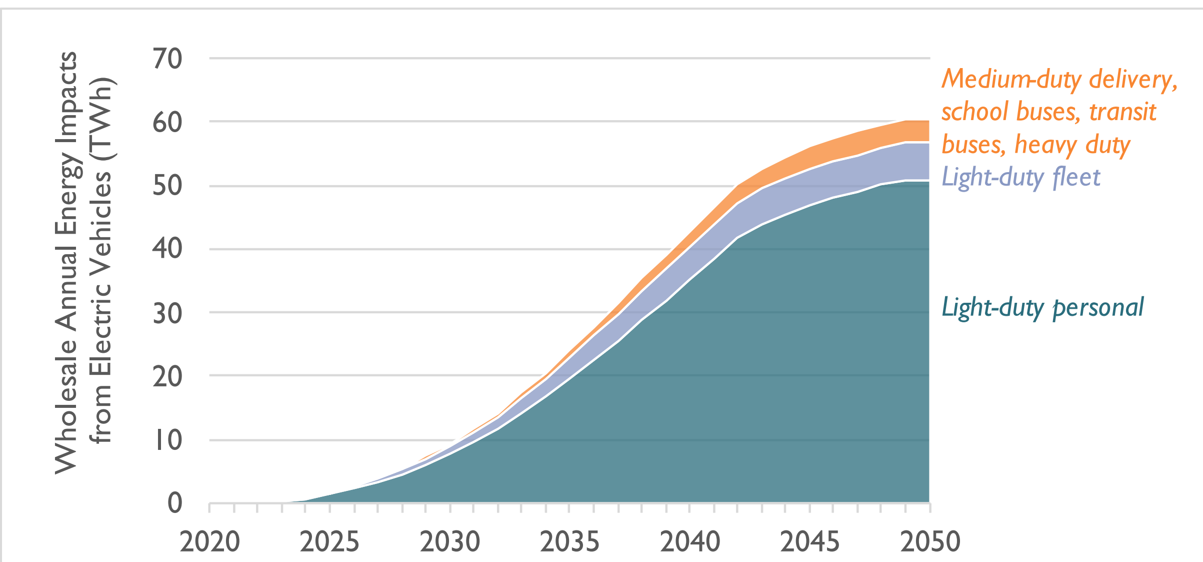
Source: "Final 2023 Transportation Electrification Forecast." April 28, 2023. Available at [https://www.iso-ne.com/static-assets/documents/2023/04/transfx2023_final.pdf. Page 10](https://www.iso-ne.com/static-assets/documents/2023/04/transfx2023_final.pdf).

Schedule MM-R1

Based on feedback from the Study Group, we added two vehicle types: heavy-duty "single" vehicles and heavy-duty "combination" vehicles.[132] The vehicles within these two types are diverse in size and use case, making it challenging to develop a sophisticated projection within the time and budget constraints of AESC 2024. As a result, we assume the adoption of these vehicles and charging load shape follows that of medium-duty vehicles, with adjustments made to reflect the number of heavy-duty vehicles relative to medium-duty vehicles (heavy-duty vehicles are fewer in number), the charging requirements of heavy-duty vehicles relative to medium-duty vehicles (heavy-duty vehicles are typically larger and heavier, implying a greater number of kWh needed to travel a single mile), and the travel requirements of heavy-duty vehicles relative to medium-duty vehicles (heavy-duty vehicles typically travel more miles per year than medium-duty vehicles, suggesting an overall higher level of annual electricity consumption).

Figure 21 illustrates the annual energy projection for electric vehicles we use in AESC 2024. By 2050, annual energy impacts from electric vehicles approach 60 TWh, about half of ISO New England's total electricity demand as of the early 2020s. The figure shows 83 percent of load is attributable to personal light-duty electric vehicles, 11 percent of load is attributable to fleet light-duty electric vehicles, and 6 percent of load attributable to other vehicle types.

Figure 21. Projected wholesale electricity consumption from electric vehicles in ISO New England for all Counterfactuals



Note: In both the CELT 2023 and AESC 2024 forecast, the first three vehicle categories (medium-duty delivery, school buses, and transit buses) are disaggregated and modeled independently. They are shown as a single series on this chart only for illustrative purposes. Likewise, both CELT 2023 and AESC 2024 model five different vehicle trajectories within each of the six states; these are not shown in this figure.

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132 Heavy-duty "single" vehicles include vehicles like dump trucks, which consist of a single chassis. In contrast, heavy-duty "combination" vehicles are those that consist of multiple parts (like a semi cab and an associated trailer).

Schedule MM-R1

Figure 22 shows the daily load profiles we use in AESC 2024 for non-holiday weekdays (separate profiles have been created for holidays and weekends). These profiles are derived from the seasonal profiles posted for each vehicle type by ISO New England in CELT 2023, and include some amount of home charging, workplace charging, and public charging.[133] These daily load profiles are also applied to the monthly variations in daily charging demand aggregated by ISO New England in CELT 2023. Under these assumptions, electric vehicles typically use less electricity in summer months than in winter months, due to HVAC-related demand and other cold weather inefficiencies. For personal light-duty vehicles, we note that ISO New England assumes an average daily charging demand in July that is about three-quarters the daily charging demand in January.

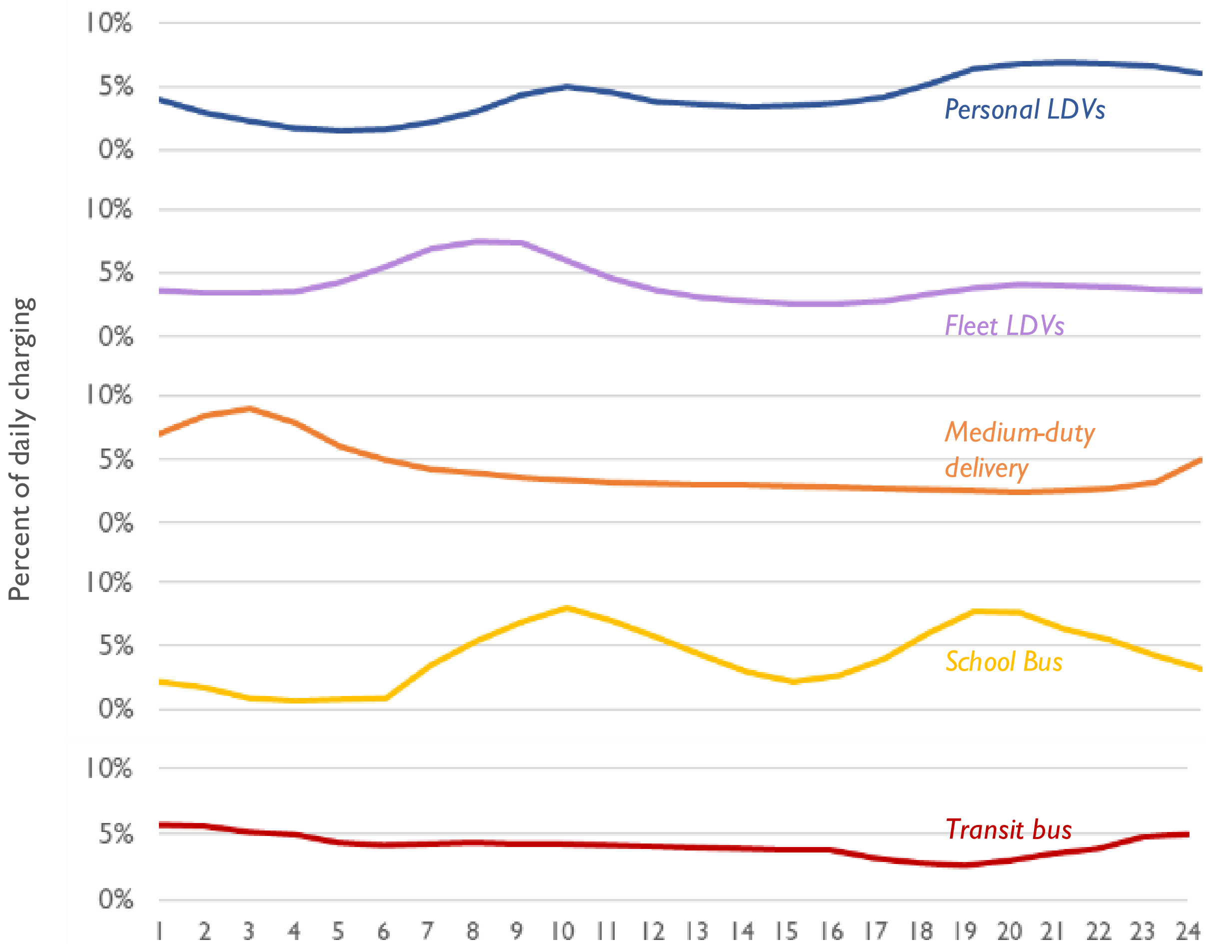
The EnCompass model estimates system peak impacts dynamically based on the combination of aggregate system load in each year, hourly load shapes, and monthly variations in demand. Our modeling assumes static load shapes in line with those described by ISO New England in its CELT 2023 forecast. We do not incorporate any assumptions related to managed charging or time-of-use rates (see Demand response section, above, for more information on this topic).

AESC 2024 includes the transportation electrification component in all counterfactuals. In other words, we assume that all transportation electrification impacts are non-programmatic.

[133] In AESC 2024, we only model a single load profile for each vehicle type, rather than profiles that vary by month or season. This is due to the relative similarity in load shapes for personal light-duty vehicles and fleet light-duty vehicles assumed by ISO New England in CELT 2023; this vehicle type has little variation in charging patterns month-to-month, and represents the vast majority of vehicles and electricity consumption.

Schedule MM-R1

Figure 22. Daily load profiles modeled in AESC 2024 for non-holiday weekdays



Note: Separate profiles (not shown) are used for weekends and holidays. Heavy-duty vehicles utilize the daily load profile for medium-duty vehicles.

Distributed generation

For the purposes of AESC 2024, "distributed generation" is assumed to include only distributed solar. As with demand response and BTM storage, we model distributed generation as a supply-side resource in the EnCompass model. Impacts from distributed generation are applied to peak demand calculations in each counterfactual.

The 2023 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 2024 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

Schedule MM-R1

modeling distributed solar, including policies modeled and load profiles, see Section 4.4: *Renewable energy* .

All counterfactuals include this component and there is no differentiation between programmatic or non-programmatic components.

Other load components not modeled in AESC 2024

There are other emerging DSM programs (see Table 43) that may be modeled using the 8,760 avoided cost values. As in AESC 2021, these resources are not modeled in any AESC 2024 counterfactuals. Likewise, AESC 2024 does not currently assume any quantity of industrial electrification other than that related to HVAC or water heating.

Table 43. 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 customers' sites through T&D wires. We develop T&D losses in AESC 2024 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 2024 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.

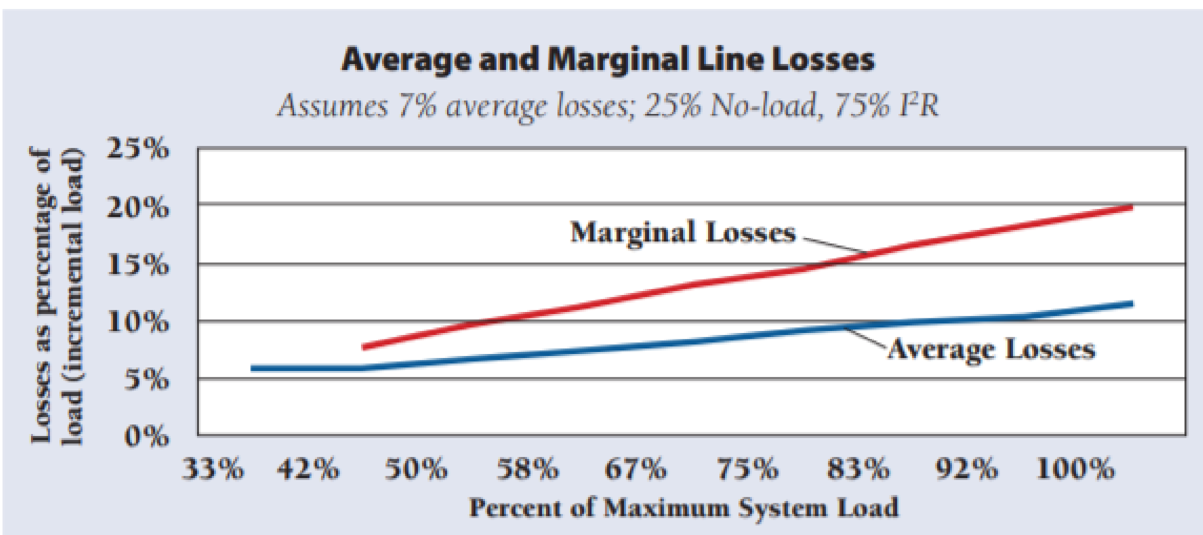
The following section primarily addresses the development of T&D losses under the first category, as it is our understanding that each program administrator calculates and applies a T&D loss factor (or uses a T&D loss factor based on state precedent). However, readers may wish to review the following section to help inform their selection of loss factors. We note that the selection of T&D loss factors is unchanged from the AESC 2021 study.

Marginal loss factors

Multiple factors affect the amount of energy loss, 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).[134] 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 line loss factors in detail. 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 23. 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 23. Average and marginal line loss factors from Lazar and Baldwin



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.

[134] Regulatory Assistant Project. 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.

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 establishing the New Jersey Cost Test.[135] In AESC 2024, 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).[136]

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 23, 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).[137]

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

Aggregate impacts

This section describes the aggregate impacts of the above load components, both in terms of annual load impacts and seasonal peak demand.

Annual load impacts

Figure 24 and Figure 25 show the aggregate annual impacts on load from all load components for Counterfactual #1 and Counterfactual #5, respectively. Counterfactual #1 (which includes transportation

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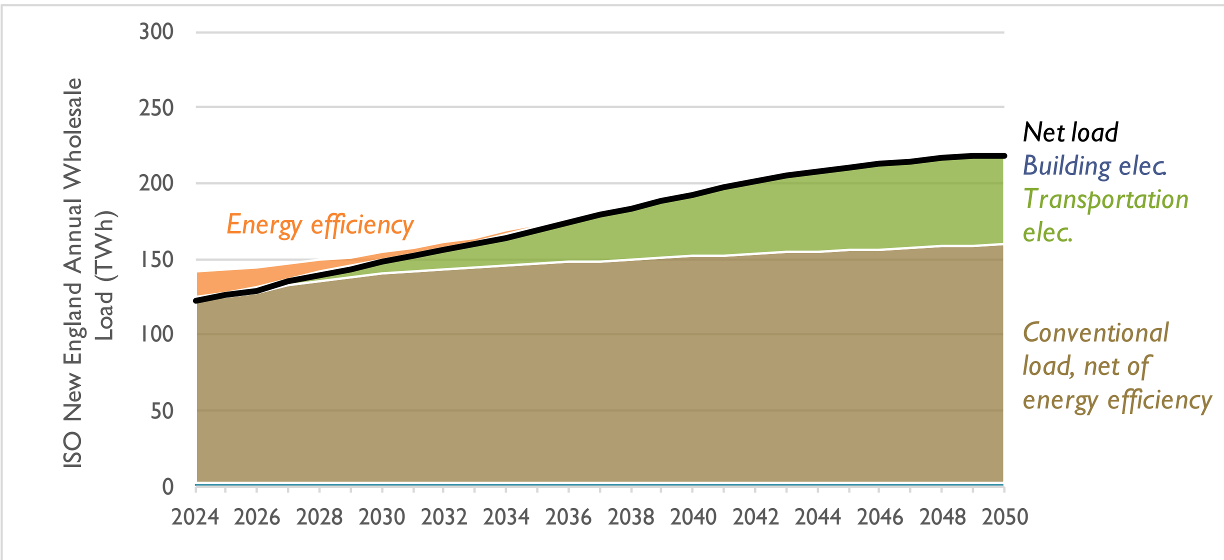
[135] New Jersey Board of Public Utilities. 2020. Order Adopting the First New Jersey Cost Test. Docket No. QO19010040 and QO20060389.

[136] Note that 6 percent is the average T&D loss factor assumed by ISO New England for its long-term energy forecast. ISO New England. April 28, 2923. *Final 2023 Heating Electrification Forecast.* Slide 41. Available at https://www.iso-ne.com/static-assets/documents/2023/04/heatFx2023_final.pdf.

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

electrification and non-programmatic BTM storage and demand response but does not include any new energy efficiency or building electrification built after 2023) reaches load levels of about 220 TWh by 2050. This is roughly a 75 percent increase in load, relative to today. Most of this increase in load is a result of transportation electrification. In comparison, Counterfactual #5 (which also includes transportation electrification, as well as new energy efficiency, building electrification measures, and both programmatic and non-programmatic BTM storage and demand response resources) reaches load levels of about 240 TWh by 2050. This is about a doubling in load, relative to today. In this counterfactual, about half of the load increase is attributable to transportation electrification and half of the load increase is attributable to building electrification.

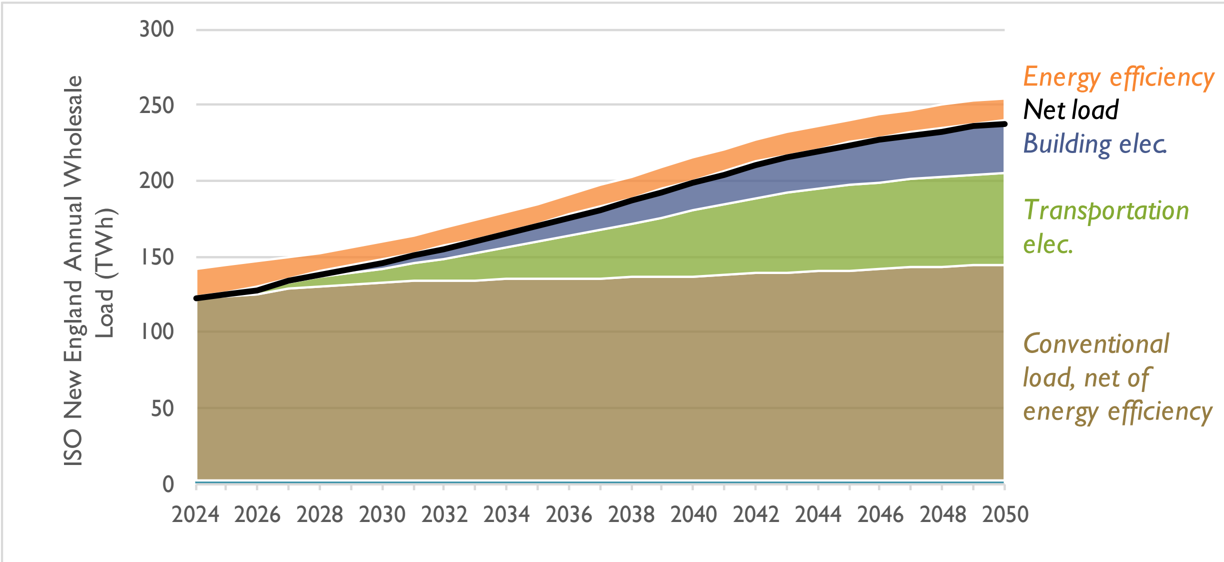
Figure 24. Aggregate load impacts, Counterfactual #1



Note: This figure does not account for demand impacts related to storage.

Schedule MM-R1

Figure 25. Aggregate load impacts, Counterfactuals #4, #5, #6



Note: This figure does not account for demand impacts related to storage.

Peak demand forecasts and capacity requirements

Synapse calculates coincident winter and summer peak demand dynamically within the EnCompass model. We apply hourly load shapes for each of the load components (conventional load, energy efficiency, transportation, and so on) to annual projections of load for each component and for each region. We then sum the resulting hourly loads for each component and each region, with the regional, coincident winter, and summer peaks identified endogenously by the model and then used for capacity market calculations. Figure 26 shows the resultant seasonal peaks for summer months (June through September, inclusive) and winter months (all eight other months) in Counterfactual #1 and #5.[138]

In Counterfactual #1, which does not include any new DERs installed after 2023 but does include demand growth from conventional load and vehicle electrification, coincident summer peak demand is projected to increase by about 57 percent, while coincident winter peak is projected to increase by about 98 percent. This leads to a 2050 where coincident winter peak approaches but does not surpass summer peak, with a 2050 winter peak just 5 percent lower than the 2050 summer peak.

Counterfactual #2, which is the same as Counterfactual #1 except for the inclusion of programmatic energy efficiency, sees summer peaks increasing by 46 percent and winter peaks increasing by 88 percent.[139] In this counterfactual, the 2050 winter peak just 3 percent lower than the 2050 summer peak.

[138] Note that peaks (exclusive of demand response and storage) for Counterfactuals #4, #5, and #6 are identical.

[139] This scenario also includes programmatic behind-the-meter storage and demand response. However, as modeled in EnCompass, these resources do not affect the demand-side peaks.

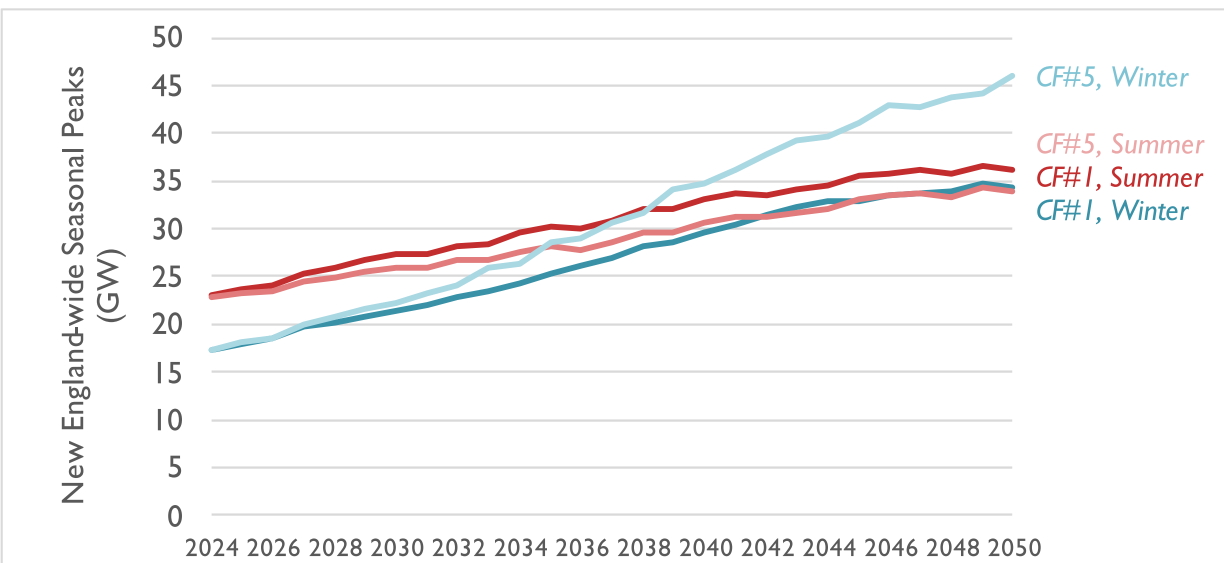
Schedule MM-R1

Meanwhile, in Counterfactual #5, which features new deployment of all programmatic DER types throughout the study period, along with load growth from conventional load and vehicle electrification, coincident winter peak demand surpasses coincident summer peak demand in 2036. By 2050, winter peak demand is 164 percent higher than in 2024. Summer peak demand increases are similar to Counterfactual #1, with increases of about 49 percent from 2024 through 2050.

Counterfactual #3 is similar to Counterfactual #5 in that it includes deployment of programmatic building electrification measures. However, it does not include programmatic energy efficiency measures. As a result, by 2050, winter peak demand is 175 percent higher than in 2024, and summer peak demand is 60 percent higher than in 2024.

We note that seasonal peak demand increases in all modeled counterfactuals are not smooth. Instead, peak demand is observed to increase (and in rare cases decrease) in ways that appear discontinuous relative to neighboring years. This is a result of each of the load components modeled in AESC increasing at different rates, in different parts of the region. This difference in rate-of-increase leads to shifts in when the peak demand may occur within each season, which can lead to discontinuous-looking results in terms of year-on-year peak demand changes. Because of this, counterfactuals with fewer modeled load components (like Counterfactual #1) generally feature smoother increases in seasonal peak demand than counterfactuals with many different modeled load components. Because we conduct our modeling with full optimization, we do not expect these shifts in total peak demand to have a significant impact on resource builds.

Figure 26. Seasonal peak demand forecasts for ISO New England in Counterfactual #1 and Counterfactual #5



Note: Peak demand projections for other counterfactuals can be found in the AESC 2024 User Interface Excel workbooks.

The load forecast in one year is used in the FCA early in the next year to set the installed-capacity requirement for the capacity period starting three years after that. For example, under the current capacity market structure, the peak forecast for the summer of 2024 (released in May 2023) will be used

Schedule MM-R1

to set the installed-capacity requirement for FCA 18 (held in February 2024) which sets the capacity obligations and prices for the period June 2027 to May 2028. Under our future conceptualization of the capacity market (starting in June 2028), we model a change to a prompt market where projections of demand for a particular year are forecasted only one year in advance of the delivery year. We note that because our models do not differentiate between prompt markets and three-year-ahead markets, there is no functional difference in terms of how projections of peak demand are used as an input to estimating avoided capacity costs in AESC 2024. For more information on how forecasted demand impacts the capacity market, see Chapter 5: *Avoided Capacity Costs*.

4.4. Renewable energy assumptions

This section contains additional information on renewable energy capacity factors and offshore wind interconnections. Most other assumptions relating to renewable energy are described in Chapter 7. *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies*.

Renewable energy capacity factors

We used data from ISO New England's 2022 New England Variable Energy Data series to create renewable dispatch shapes.[140] This dataset includes modeled hourly historical wind and solar generation for 2000 to 2021. For our core energy modeling, we used the renewable dispatch data from 2002 to be consistent with our load shape weather year. We then scaled these 2002 dispatch shapes to match the annual capacity factors used in SEA's REMO model to ensure our annual renewable energy generation was consistent with the REMO assumptions. For the stochastic capacity modeling (described below in Chapter 5: *Avoided Capacity Costs*), we used the same ISO New England dataset to create similar dispatch shapes for 2000 to 2021.

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. For southern New England, we assume that offshore wind built in southern New England is built in the U.S. Bureau of Ocean Energy Management's designated lease zones (see Figure 27). We note there is ongoing discussion on where these offshore wind facilities will interconnect, including an ongoing multistate effort to comprehensively plan for these new resources.[141] Options for interconnection include locations on or near Cape Cod; New London, Montville, or Bridgeport, CT; Quonset, RI; Brayton Point, MA; or in the Greater Boston region. In order to minimize price anomalies, we distribute the offshore wind interconnection points throughout southern New England. Although there is uncertainty about which interconnection points will be used, to what degree, and when, we rely on a simplified "cycling"

[140] See ISO New England. *2022 ISO-NE Variable Energy Resource (VER) Data Series (2000-2021) Rev. 0*. May 11, 2022. available at https://www.iso-ne.com/static-assets/documents/2022/05/2022_isone_ver_dataset_2000_2021_rev0.zip.

[141] See "New England Energy Vision" materials, available at https://newenglandenergyvision.com/.

Schedule MM-R1

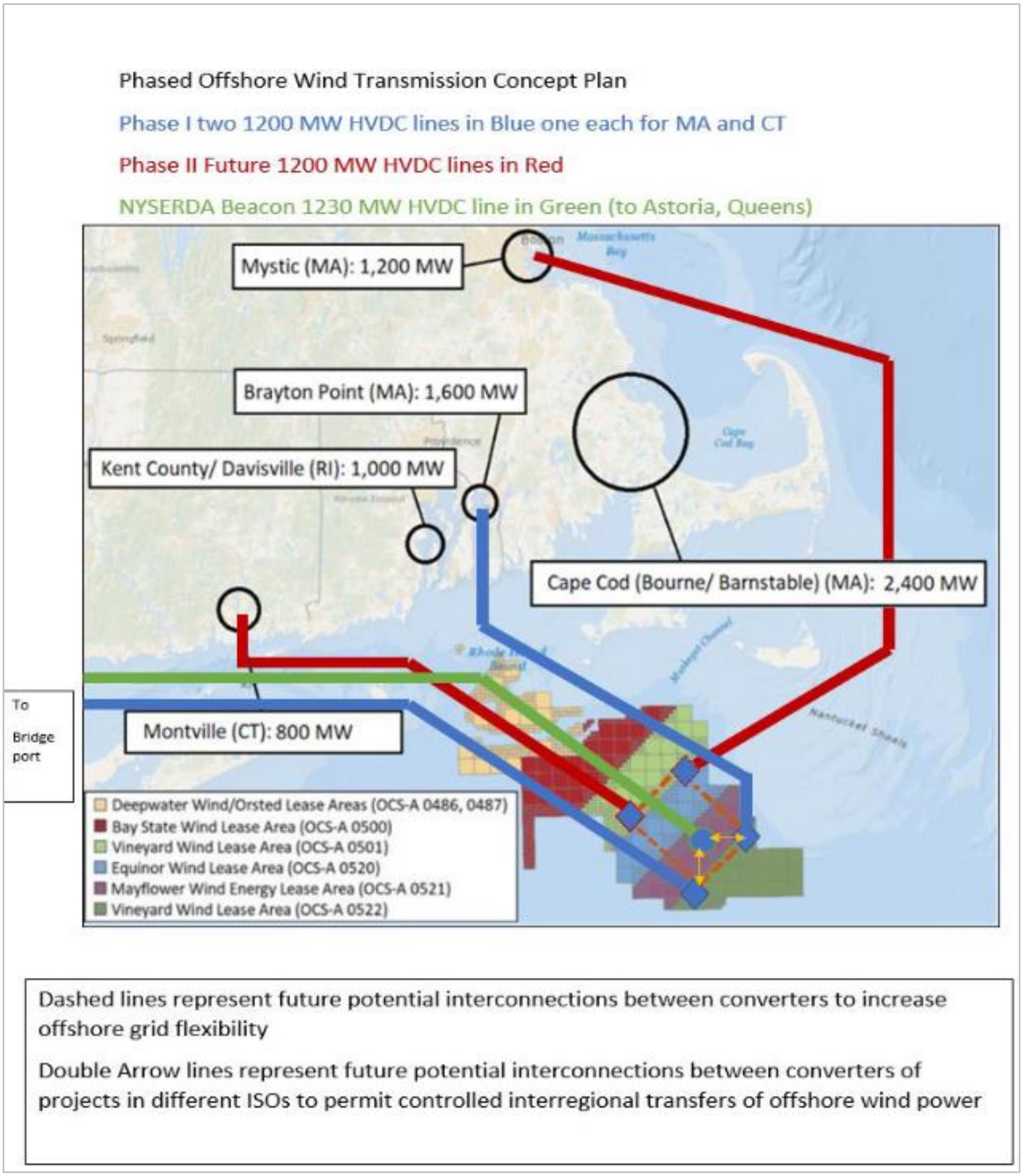
methodology to allocate the offshore wind throughout various modeling zones. Using 1200-MW blocks, we change the interconnection point of offshore wind projects as they are built, moving from Phase I, to Phase 2, to Phase 3 (as described in Figure 27), and repeating this cycle as necessary. This results in offshore wind becoming roughly evenly distributed across four different EnCompass modeling zones.

We apply a similar approach to offshore wind being deployed in southeastern Maine. Less information is currently available on points of interconnection for offshore wind projects likely to be deployed in the Gulf of Maine. Based on information in a July 2023 NREL study, we assume these projects are interconnected at points in Southeastern Maine (e.g., Yarmouth), New Hampshire (e.g., Seabrook), and metro Boston (e.g., Cape Ann or Boston itself). This results in offshore wind becoming roughly evenly distributed across three different EnCompass modeling zones. We note that in all counterfactuals, substantial quantities of offshore wind are not built in Maine until the late 2030s, minimizing the impact these assumptions have on near-term avoided costs.

We note that because the offshore wind costs being modeled include an average, incremental transmission cost (as opposed to a location-specific transmission cost, or a transmission cost based on a strategic regional approach to interconnection), our "cycling" approach may overestimate the cost of some offshore wind projects and underestimate the costs for other projects.

Schedule MM-R1

Figure 27. Bureau of Ocean Energy Management lease zones in southern New England and potential interconnection points



Source: New England Energy Vision. 2022. "New England States' Transmissions RFI Technical Session," slide 4. https://newenglandenergyvision.files.wordpress.com/2022/10/state-of-ct_-tech-mtg-slides.pdf.

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.[142]

Note that plant additions and retirements may be affected by federal policies, including the IRA and U.S. EPA's proposed regulations under Section 111 of the *Clean Air Act*. For more on these expected impacts, see below text (where relevant) and Section 4.8: *Embedded emissions regulations*.

In addition, all existing resources will be eligible to endogenously retire starting on June 1, 2028, the start of the FCA-18 commitment period.

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 44). None of the three units have announced a retirement date. 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.[143] Furthermore, we note that the IRA includes zero-emission production tax credits for nuclear plants. Although this financial support expires in 2032 under the current text of the IRA, it is indicative of the broad federal support for existing nuclear plants in the United States. 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.[144]

Table 44. Nuclear unit detail

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

[142] 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.

[143] NEI. "Nuclear Energy in the U.S." *Nei.org*. Available at https://www.nei.org/resources/statistics.

[144] 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. These assumptions do not appear to have been modified in more recent editions of the Regional System Plan (see https://www.iso-ne.com/system-planning/system-plans-studies/rsp).

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

Coal units

As of September 2023, there are two coal units operating in New England, both located at the Merrimack power plant (see Table 45). Other recently retired plants include Bridgeport Station 3 (retired June 2021), Brayton Point (retired June 2017), Mount Tom (retired June 2014), Salem Harbor (retired June 2014), and Schiller (retired July 2020).

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. Both Merrimack coal units feature a wet fluidized gas desulphurization (FGD) system to control for sulfur dioxide (SO_2), a selective catalytic reduction (SCR) system to control for nitrogen oxide (NO_X), and an electrostatic precipitator (ESP) to control for particulate matter. In 2021, Merrimack's two coal units operated with an aggregate capacity factor of 7 percent. All four Merrimack units have capacity commitments through FCA-16 (i.e., through May 31, 2026), but not in FCA-17. Given this change in obligation, we assume that both Merrimack 1 and 2 retire on May 31, 2026, while the other two (gas-fired) Merrimack units continue to be operational throughout the analysis period.

Table 45. Coal unit detail

Unit	State	Capacity (MW)	Announced Retirement Date	Modeled Retirement Date
Merrimack 1	NH	113.6	None	May 2026
Merrimack 2	NH	345.6	None	May 2026

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 77 MW of new capacity additions from natural gas or oil resources. Table 46 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 46. Incremental natural gas and oil additions

Unit	State	Capacity (MW)	Modeled Online Date	Unit Type
Hartford Hospital Cogeneration 5	CT	5.5	Jan 2026	Combined Cycle
Hartford Hospital Cogeneration 6	CT	5.5	Jun 2026	Combustion Turbine
MMWEC Simple Cycle Gas Turbine	MA	65	Jun 2023	Combustion Turbine

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 47). 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 47. Major natural gas and oil retirements

Unit	State	Capacity (MW)	Announced / Modeled Retirement Date	Unit Type	Notes
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	-
Cape Gas Turbine GT4	MA	17.5	May 2026	Combustion Turbine	FCA16 Obligation through May 2026
Cape Gas Turbine GT5	MA	17.5	May 2026	Combustion Turbine	FCA16 oblig through May 2026
William F Wyman Hybrid (Yarmouth) 3	ME	113.6	May 2027	Steam Turbine	FCA17 oblig. Through May 2027
William F Wyman Hybrid (Yarmouth) 4	ME	632.4	May 2027	Steam Turbine	FCA17 oblig. Through May 2027
Middletown 2	CT	113.6	May 2027	Steam Turbine	FCA oblig. through May 2027
Middletown 4	CT	414.9	May 2027	Steam Turbine	FCA oblig. through May 2027
Middletown 10	CT	18.5	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
Norden #2	CT	2	May 2026	Steam Turbine	FCA16 oblig through May 2026
Norden #3	CT	2	May 2026	Steam Turbine	FCA16 oblig through May 2026

Schedule MM-R1

Large-scale battery storage resources

Table 48 identifies the battery storage resources assumed to be added during the study period. This list includes over 730 MW of new battery storage. These resources are in addition to the BTM storage resources described above in Section 4.3: *New England system demand and energy components*. Data on capacities and online dates are from EIA's Form 860 and the resources with obligations in the forward capacity market.

Table 48. New battery storage additions

Unit	State	Capacity (MW)	Modeled Online Date	Unit Type	Source
Outer Cape Community Battery	MA	25	Dec 2022	Battery	EIA 860
Syncarpha Hybrid CSGs*	MA	9	2021, 2022**	Battery	EIA 860
AES Distributed Energy Projects*	MA	35.8	2021,2022**	Battery	EIA 860
Ocean State BTM	RI	3	Jun 2022	Battery	EIA 860
Other ISO-NE < 5 MW Projects*	MA	90.2	2021, 2022	Battery	EIA 860
Rumford ESS	ME	4.9	Jun 2021	Battery	FCA
Medway Grid, LLC	MA	250	Jun 2026	Battery	FCA
Cross Town Energy	ME	175	Jun 2026	Battery	FCA
Cranberry Point Battery Storage	MA	150	Jun 2026	Battery	FCA
Great Lakes Millinocket	ME	20	Jun 2026	Battery	FCA

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.

Other resources (e.g., biomass, wind) may have specific retirement dates.[145] These retirements and additions are accounted for in Section 4.4: *Renewable energy* .

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

Schedule MM-R1

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 49 if there is a peak demand need. EPA recently announced its proposed *Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants,* which is discussed in greater depth below in Section 4.8: *Embedded emissions regulations.* We assume all new fossil units will be compliant with this rule. As a result, some of the operational parameters (e.g., fuel blends and capacity factors caps) are significantly different compared to the 2021 AESC Study. Table 50 outlines the compliance options for new gas plants that we were modeled, along with the retrofit costs and incremental operational costs associated with the given retrofits. The base costs (capex, fixed and variable O&M, and heat rates) are similar though. Note that there are two types of each generic gas addition: 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.[146] Our analysis does not take permitting into account for these endogenous builds; resources are built purely according to least-cost economics of the electricity system.

Table 49. Operational characteristics of generic conventional resources assumed in the EnCompass model

		Natural gas-fired combined cycle	Natural gas-fired combustion turbine	Battery Storage	Long-Duration Storage
Maximum size	*MW*	702	237	10	100
Minimum size	*MW*	225	120	-	-
Heat rate	*Btu/kWh*	6,360	9,720	-	-
Variable O&M costs	*2024 $/MWh*	$2.13	$7.27	-	-
Fixed O&M costs	*2024 $/kW-yr*	$33.40	$26.29	$40	$18
Unabated CO_2 emissions rate	*lb/MMBtu*	119	119	-	-
Duration	*hours*	-	-	4, 6 and 8	50
Round Trip Efficiency	*%*	-	-	85%	50%
Capital costs (exclusive of any retrofits)	*2024 $/kW*	$1,347 - $1,096	$1,214 - $984	$2,695 - $934	$2,269

Note: Each type of generic fossil resource may be fueled either with natural gas or fuel oil. Range of capital costs represents 2027-2050 cost trajectory and range of durations for battery storage.
Source: NREL's 2023 ATB; "Clean, Reliable, Affordable: The Value of Multi-Day Storage in New England." Form Energy. September 2023. Available at https://formenergy.com/wp-content/uploads/2023/09/Form-ISO-New-England-whitepaper-09.27.23.pdf.

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

Schedule MM-R1

Table 50. Compliance pathways and associated costs for new gas units under EPA's proposed *Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants*

System Contribution	Resource Type	Fuel Blend	Capacity Factor Constraint	Carbon Capture and Sequestration (CCS)	Retrofit Cost *(2024 $/kW)*	Incremental O&M costs *(2024 $)*
Peaker	Combined Cycle	Only ever burns natural gas	20%	No	none	none
	Combustion Turbine	Only ever burns natural gas	20%	No	none	none
Intermediate	Combined Cycle	Natural gas through 2031, 30% hydrogen blend (by volume) in 2032 onward	50%	No	none	none
	Combustion Turbine	Natural gas through 2031, 30% hydrogen blend (by volume) in 2032 onward	50%	No	none	none
Baseload	Combined Cycle	Natural gas through 2031, 30% hydrogen blend (by volume) from 2032–2037, 96% hydrogen blend in 2038 onward	No limit	No	$304	none
	Combined Cycle	Natural Gas	No limit	90% CCS requirement starting in 2038. Parasitic load is modeled.	$1,240	FOM: $17/kW-yr VOM: $19/MWh

Note: Assumes 25% base capex to retrofit facility.

Sources: Öberg, Simon, Mikael Odenberger, and Filip Johnsson. 2020. "Exploring the competitiveness of hydrogen-fueled gas turbines in future energy systems." International Journal of Hydrogen Energy; Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies, Sargent and Lundy.

4.6. Transmission, imports, and exports

This section describes the existing, under construction, and planned intra-regional transmission modeled in the AESC 2024 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.

Schedule MM-R1

Intra-regional transmission

The interface limits used in the AESC 2024 study reflect both the existing system and the ongoing transmission upgrades discussed in ISO New England's Regional System Plan.[147] 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 51).[148]

Table 51. Group transmission limits

Transmission Limit	Path	A to B (MW)	B to A (MW)
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		

Note: Internal transmission limits are based on ISO New England's published Transmission Transfer Zone Capabilities for FCA 18 in https://www.iso-ne.com/static-assets/documents/2023/03/a08_fca_18_transmission_transfer_capability_and_capacity_zone_development.pptx, slide 8.

[147] 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.

[148] Note that recent analysis by ISO New England that 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, AESC 2024 models one new 1200 MW transmission line between Maine West Central and Massachusetts Central beginning in 2030. The transmission line is intended to help limit issues of curtailment in Maine. For more information, see ISO New England. *2050 Transmission Study Draft Report*. November 1, 2023. Available at https://www.iso-ne.com/static-assets/documents/100005/2023_11_01_pac_2050_transmission_study_draft.docx.

Schedule MM-R1

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. We model and export quantities between New England and adjacent balancing areas on an hourly basis, with an 8760-shape based on averages of recent historical quantities. Synapse calibrated transfers on these lines such that transfers modeled in historical years resemble actual historical transfers.

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.[149] 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. Per the latest data available, we assume this line will instead be energized on January 1, 2027. 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. See Section 7.1: *Assumptions and methodology* for more information about this assumption.

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.)
- 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 O&M costs
- Commitment bid adders and multipliers
- Forced outage rates and planned outage rates and schedules

[149] See the New England Clean Energy Connect website at https://www.necleanenergyconnect.org/ for more information. Our analysis does not currently make any assumptions regarding the construction of the proposed Twin States Energy Link project (https://www.twinstatescleanenergylink.com/) or any other transmission projection conceived to increase connections between ISO New England and adjacent balancing authorities.

- 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
- CO_2 emission 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

The model uses unit operational restraints (for example, minimum up times and ramp rates) 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.

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, New Jersey, and Virginia) conduct four auctions 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 2021 through 2030.[150] Under this extended program design, the RGGI states are set to continue reducing CO_2 emissions through 2030, eventually achieving a CO_2 emissions level 30 percent below 2020 levels. This program design also put forth a number of changes to the "Cost Containment Reserve" (a mechanism that allows for the release of more allowances in an auction if the price exceeds a certain threshold) and the creation of an "Emissions Containment Reserve" (a mechanism which withholds a number of

[150] For more information on the proposed program review, see https://www.rggi.org/program-overview-and-design/program-review.

Schedule MM-R1

available allowances if the allowance price remains below a certain threshold). Together, these triggers effectively act as a floor and ceiling on RGGI prices.[151, 152] The RGGI states are currently conducting a Third Program Review, which will likely set cost containment reserve (CCR) and emissions containment reserve (ECR) caps between 2031 and 2040 and may make other adjustments to the caps for 2026 to 2030.[153]

In addition, the RGGI region has been expanding and changing in recent years. The first new state to join RGGI was New Jersey in January 2020 (rejoining the program after leaving it in 2012).[154] Later in 2020, Virginia finalized its rulemaking to join RGGI, effective January 1, 2021.[155] Then in June 2023, the Virginia Air Pollution Control Board voted to withdraw the state from RGGI at the end of the year, with environmental groups challenging the Board's authority to make this decision.[156] Pennsylvania started the process of joining RGGI in 2019 and finalized its rulemaking in April 2022. However, Pennsylvania has yet to participate in any RGGI auctions, and its role in RGGI remains uncertain due to ongoing legal challenges.[157]

Figure 28 displays the recent prices for RGGI allowances from auctions in 2010 through 2023. This figure also shows the prices associated with the ECR and 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. 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.

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151 The true floor price is the minimum reserve price, which is lower than the ECR price.

152 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.

153 Regional Greenhouse Gas Initiative. Last accessed August 8, 2023. "Program Review." *RGGI.org.* Available at: https://www.rggi.org/program-overview-and-design/program-review.

154 New Jersey Department of Environmental Protection. Last accessed August 21, 2023. "Regional Greenhouse Gas Initiative." *state.ny.us.* Available at https://www.state.nj.us/dep/aqes/rggi.html.

155 Virginia Department of Environmental Quality. Last accessed August 21, 2023. "Carbon Trading." *Deq.virginia.gov.* Available at https://www.deq.virginia.gov/our-programs/air/greenhouse-gases/carbon-trading.

156 Southern Environmental Law Center. August 21, 2023. "We're suing to hold the line on Virginia's climate progress". Available at: https://www.southernenvironment.org/news/were-suing-to-hold-the-line-on-virginias-climate-progress/.

157 Pennsylvania Department of Environmental Protection. Last accessed August 21, 2023. "Regional Greenhouse Gas Initiative." *Dep.pa.gov.* Available at https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx. See also the recent PA Supreme Court decision, which is under appeal (Huangpu, Kate. "Pa. court strikes down a key climate program, but environmentalists expect an appeal." Spotlight PA. November 1, 2023. Available at https://www.spotlightpa.org/news/2023/11/regional-greenhouse-gas-rggi-struck-down-pennsylvania-climate-change-fossil-energy/.

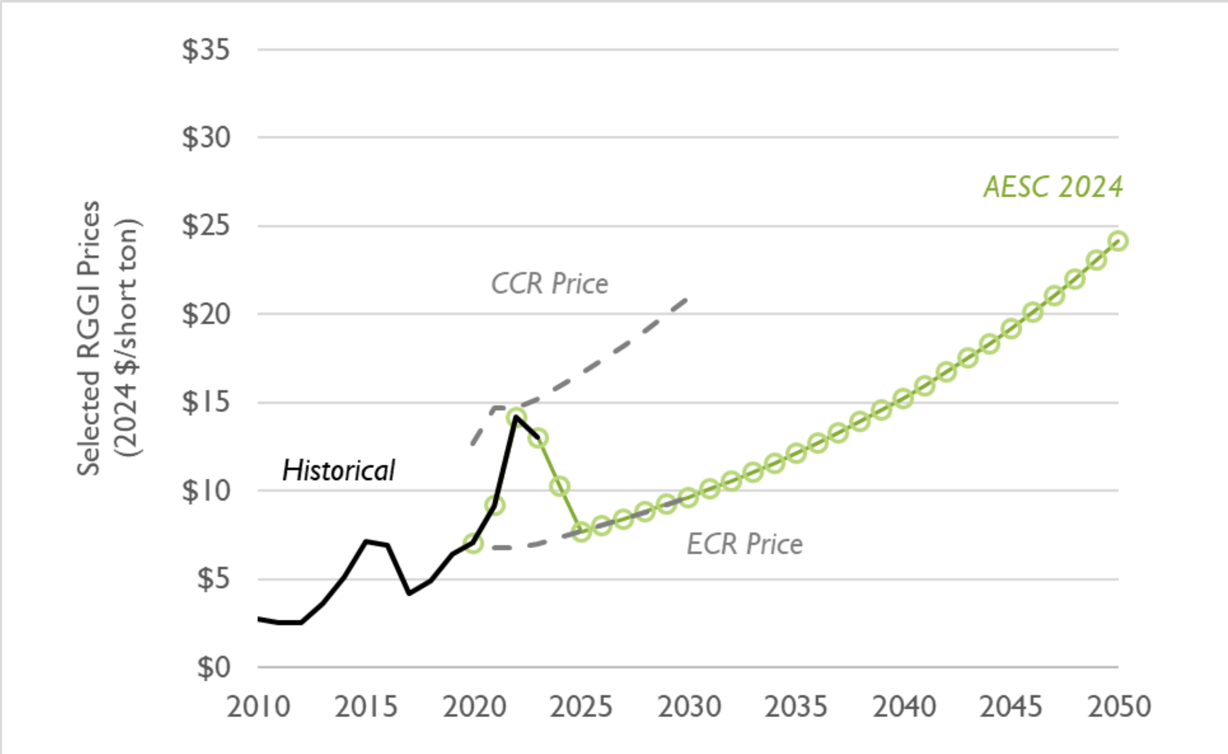
Schedule MM-R1

Because the RGGI region includes states not modeled in the AESC 2024 study (New York, Delaware, Maryland, New Jersey, Virginia, and Pennsylvania) and is in fact dominated by emissions outside of New England (see Figure 29)—even in a future where Virigina and Pennsylvania withdraw from the program—we model the effects of RGGI as an exogenous price rather than a strict cap on emissions. The RGGI price modeled in AESC 2024 is based on historical prices through 2023, an average of historical prices and the ECR trigger price in 2024, and then a trajectory extending the ECR through 2050. This trajectory reflects a future in which reductions in the RGGI cap are continued after the current compliance period ends in 2030. A modeling report from the University of Pennsylvania's Kleinman Center and Resources from the Future also forecasts 2030 RGGI prices at the ECR price (without Pennsylvania).[158] The report attributes recent high historical RGGI prices to the increase in gas prices, expected to return to previous forecasts by 2025, as well as temporary investor behavior. We observe that prices published as part of RGGI's Third Program Review in September 2023 vary widely according to the scenario being considered.[159] Although none of the scenarios modeled by RGGI are entirely aligned with the framing used by any of the AESC 2024 counterfactuals and sensitivities, cost projections modeled by RGGI range from (1) being roughly halfway between the RGGI ECR and CCR (as is the case with a flat extension of RGGI's cap, but a regional acceleration to zero-emitting electricity in 2035) to (2) being aligned with the ECR and the AESC 2024 assumption (as is the case with an extension of RGGI's current declining cap, and a regional acceleration to zero-emitting electricity in 2035), to (3) being priced at a near-zero transactional cost, below the ECR (as is the case with a flat extension of RGGI's cap, and a regional acceleration to zero-emitting electricity in 2040).

[158] Burtraw, D. et al. "The Prospects for Pennsylvania as a RGGI Member." Resource for the Future and Kleinman Center for Energy Policy at UPenn. May 2023. Available at https://kleinmanenergy.upenn.edu/wpcontent/uploads/2023/05/Report-23-04.pdf.

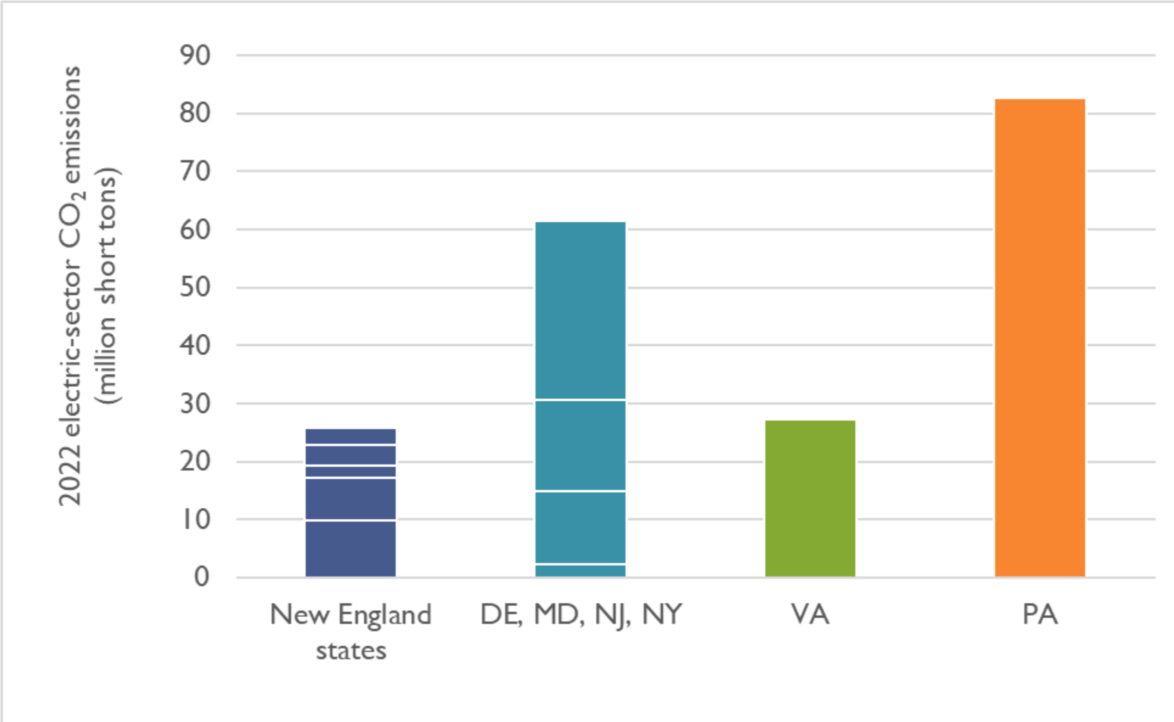
[159] *Regional Greenhouse Gas Initiative Program Review: Public Meeting*. RGGI.org. September 26, 2023. Available at https://www.rggi.org/sites/default/files/Uploads/Program-Review/2023-09-26/RGGI_26_Sept_2023_Meeting_Presentation.pdf. Slide 28.

Figure 28. Historical RGGI allowance prices, the prices associated with the cost containment reserve (CCR) and emissions containment reserve (ECR), and RGGI prices used in AESC 2024



Schedule MM-R1

Figure 29. Electric sector CO_2 emissions in existing and proposed RGGI states, 2022



Source: EPA Clean Air Markets Program dataset, available at https://campd.epa.gov/data/custom-data-download.

Massachusetts Global Warming Solutions Act and MassDEP regulations

AESC 2024 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 LSEs. Impacts of these policies in $-per-metric-ton terms are available in *Appendix G: Marginal Emission Rates* .

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 52 lists the affected power plants under this regulation. In the AESC 2024 study, we modeled this regulation as a state-wide limit through which plants receive CO_2 allowances pursuant to 310 CMR 7.74 at the start of each year.[160] The emissions limit starts at 9.1

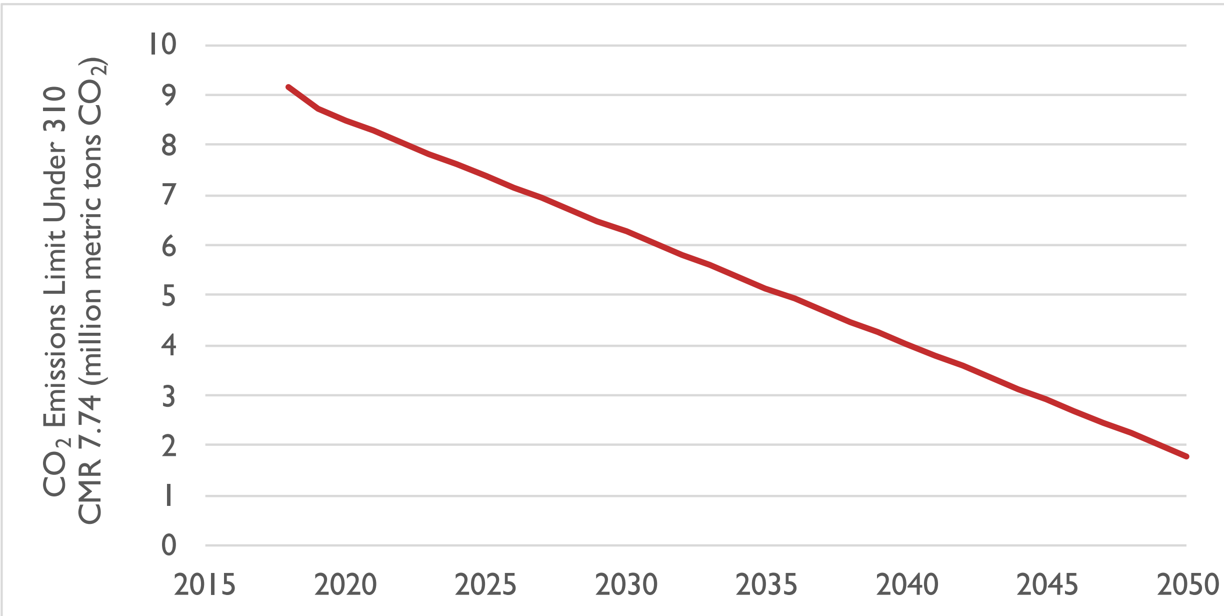
[160] We understand that allowances may be distributed through free allocation, through an auction, or through some combination thereof. We do not plan to make a distinction between these approaches in the 2018 AESC study, as the approach is unlikely to substantially impact allowance prices.

Schedule MM-R1

million metric tons in 2018, 8.7 million metric tons in 2019 and 8.5 million metric tons in 2020. The limit then declines by about 0.2 million metric tons per year until reaching 1.8 million metric tons in 2050 (see Figure 30).[161]

In this analysis, we assume that both new and existing units fall under the same aggregate limit. Table 52 lists all the existing units affected by the rule. We assume that both new and existing units are 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.

Figure 30. Analyzed electric sector CO_2 limits under 310 CMR 7.74



[161] For the latest information on limits under 310 CMR 7.74, see Massachusetts Department of Environmental Protection. Proposed Amendments to 310 CMR 7.74. January 4, 2023. Available at https://www.mass.gov/doc/310-cmr-774-amendments/download, page 3.

Schedule MM-R1

Table 52. List of generating units modeled as subject to 310 CMR 7.74

ORSPL	Facility	Unit Type	Fuel Type	EnCompass Unit Name
1588	Mystic	ST	Natural Gas	Mystic Generating Station:7
1588	Mystic	CC	Natural Gas	Mystic Generating Station:G941
1588	Mystic	CC	Natural Gas	Mystic Generating Station:G942
1592	Medway Station	GT	Oil	Exelon Medway LLC:GT1
1592	Medway Station	GT	Oil	Exelon Medway LLC:GT2
1592	Medway Station	GT	Oil	Exelon Medway LLC:GT3
59882	Exelon West Medway II LLC	GT	Natural Gas	Exelon West Medway II LLC:GT
1595	Kendall Green Energy LLC	ST	Natural Gas	Kendall Square Station:JET1
1595	Kendall Green Energy LLC	CC	Natural Gas	Kendall Square Station:CC1
1599	Canal Station	ST	Oil	Canal:1
1599	Canal Station	ST	Oil	Canal:2
1599	Canal Station	GT	Oil	Canal:3
1642	West Springfield	ST	Oil	Essential Power Massachusetts LLC:3
1642	West Springfield	GT	Natural Gas	Essential Power Massachusetts LLC:GT1
1642	West Springfield	GT	Natural Gas	Essential Power Massachusetts LLC:GT2
1660	Potter	CC	Natural Gas	Potter Station 2:POT2
1660	Potter	GT	Natural Gas	Potter Station 2:GT:52.6MW(2)
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:8
1682	Cleary Flood	OT	Natural Gas	Cleary Flood:CC1
6081	Stony Brook	CC	Oil	Stony Brook:CC1
6081	Stony Brook	GT	Oil	Stony Brook:1
10307	Bellingham	CC	Natural Gas	Bellingham Cogeneration Facility:CC1
10726	MASSPOWER	CC	Natural Gas	Masspower:G321
50002	Pittsfield Generating	CC	Natural Gas	Pittsfield Generating LP:CC1
52026	Dartmouth Power	CC	Natural Gas	Dartmouth Power Associates LP:CC1
52026	Dartmouth Power	GT	Natural Gas	Dartmouth Power Associates LP:GT1
54586	Tanner Street Generation, LLC	CC	Natural Gas	Tanner Street Generation:CC1
54805	Milford Power, LLC	CC	Natural Gas	Milford Power Project:CC1
55026	Dighton	CC	Natural Gas	Dighton Power Plant:CC1
55041	Berkshire Power	CC	Natural Gas	Berkshire Power:CC1
55079	Millennium Power Partners	CC	Natural Gas	Millennium Power:CC01
55211	ANP Bellingham Energy Company, LLC	CC	Natural Gas	ANP Bellingham Energy Project:CC1
55212	ANP Blackstone Energy Company, LLC	CC	Natural Gas	ANP Blackstone Energy Project:CC1
55317	Fore River Energy Center	CC	Natural Gas	Fore River Generating Station:G942
1626	Salem Harbor	CC	Natural Gas	Salem Harbor Station NGCC:CC1
1626	Salem Harbor	CC	Natural Gas	Salem Harbor Station NGCC:CC2

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 can be found in Section 4.4: *Renewable energy* .

Schedule MM-R1

Other environmental regulations and policies

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, nitrogen oxides, and mercury

Synapse examined allowance prices 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 2022 SO_2 spot auctions are very low, at or around $0.02 per short ton.[162] Because of this, and because of the relatively small quantity of SO_2 emissions in New England relative to the rest of the country, we do not model any embedded SO_2 prices.

Likewise, 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 including AESC 2021.

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

Other state-specific CO_2 policies

All six New England states have specified a goal or target for reducing CO_2 emissions (see Table 53). 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 2024 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.[163]

[162] U.S. EPA. Last accessed August 10, 2023. "2022 SO_2 Allowance Auction." *EPA.gov*. Available at https://www.epa.gov/power-sector/2022-so2-allowance-auction#tab-2.

[163] Note that AESC 2024 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 53. State-specific GHG emission reduction targets for 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" established an interim goal of 45% below 2001 levels by 2030. See https://www.cga.ct.gov/2018/act/pa/pdf/2018PA-00082-R00SB-00007-PA.pdf
ME	80% below 1990 levels	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) 45% below 1990 levels by 2030; (b) by 2040, the gross annual GHG emissions level must, at a minimum, be on an annual trajectory sufficient to achieve the 2050 annual emissions target; and (c) net zero emissions beginning 2045.
MA	85% below 1990 levels; Net zero	Statutory Target	Senate Bill No. 9: "An Act Creating A Next-Generation Roadmap for Massachusetts Climate Policy" (2021 Climate Law). See https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download and https://www.mass.gov/doc/2025-and-2030-ghg-emissions-limit-letter-of-determination/download	The Executive Office of Energy and Environmental Affairs (EEA) has set the following interim goals: (a) 33% below 1990 levels by 2025 and (b) 50% below 1990 levels by 2030. The EEA is also required to set a 2040 reduction goal of at least 75% below 1990 levels.
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	Net zero	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	The legislation has the following interim goals: (a) 45% below 1990 levels by 2030 and (b) 80% below 1990 levels by 2040.
VT	80% 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	The legislation has the following interim goals: (a) 26% below 2005 levels by 2025 and (b) 40% below 1990 levels by 2030.

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

Schedule MM-R1

Massachusetts sector-based sublimits

The 2021 Climate Law in Massachusetts directed the Executive Office of Energy and Environmental Affairs (EEA) to adopt sector-specific emissions sublimits for every five years between 2020 and 2050.[164] These sublimits are intended to complement the state's economy-wide emissions limits, targeting the following sectors: electric power, transportation, C&I heating and cooling, residential heating and cooling, industrial processes, and natural gas.

The electric power sector emissions category includes the combustion of fuels in power plants located in Massachusetts as well as emissions from electricity generated in or imported into ISO New England to meet Massachusetts' electricity demand. These totals also take into account renewable and clean energy credits from the state's Renewable Portfolio Standard and Clean Energy Standards. The heating and cooling sectors include all onsite combustion of fuels. The natural gas emissions sector represents fugitive emissions from natural gas distribution and service. The Massachusetts *Clean Energy and Climate Plan for 2025 and 2030* provides details on the sector-based sublimits for 2025 and 2030, and the *Clean Energy and Climate Plan for 2050* provides these details for 2050.[165, 166] The emission sublimits relevant to the sectors addressable by programmatic DERs are shown in Table 54.[167]

Table 54. Sector-based sublimits describing required emission reductions relative to 1990 levels

	Residential heating and cooling	Commercial and industrial heating and cooling	Electric Power
2025	29%	35%	53%
2030	49%	49%	70%
2050	95%	92%	93%

Sources: https://www.mass.gov/doc/2025-and-2030-ghg-emissions-limit-letter-of-determination/download and https://www.mass.gov/doc/determination-letter-for-the-2050-cecp/download.

The following sections describe how we modeled these sublimits for AESC 2024. We note that, although these calculations have been performed for Massachusetts, we believe that an analogous methodology is appropriate to be applied to any other states with emissions limits or sublimits, or any other states with Clean Heat Standards similar to the one proposed in Massachusetts.

164 Senate Bill No. 9, 2021: "An Act Creating A Next-Generation Roadmap for Massachusetts Climate Policy", available at https://malegislature.gov/Bills/192/S9/BillHistory.

165 Massachusetts *Clean Energy and Climate Plan for 2025 and 2030*, available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030.

166 Massachusetts *Clean Energy and Climate Plan for 2050*, available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050.

167 We note that there are other sectors with sublimits (e.g., transportation, natural gas distribution & service, and industrial processes). However, these are not considered in AESC 2024 because the Massachusetts program administrators do not currently offer measures or programs that address emissions in these sectors.

Electric sector

AESC 2024 does not explicitly model compliance with the electric sector sublimit. Instead, we observe the emission reductions modeled in the EnCompass model for Massachusetts and compare these with the emission levels required by the sublimits. This is done due to the number of policies that are already deployed in Massachusetts that either purposefully or indirectly achieve emission reductions over time, even without electric energy efficiency (including 111, RGGI, 310 CMR 7.74 and 310 CMR 7.75, and various other renewable policies). Figure 31 shows the emissions modeled in Counterfactual #1. The components of this figure are estimated as follows:

- The red “electric sector GHG sublimits” represent the quantity of allowable GHG emissions in the electric sector, for Massachusetts. These values are defined for 2025, 2030, and 2050 in terms relative to the 1990 level of emissions (see Table 54). All other values are interpolated (except 2024, which re-uses the 2025 level of emissions).
- The yellow “310 CMR 7.74” series describes the cap on in-state emissions from most of the large electric sector power plants in Massachusetts.
- The dark blue “in-state emissions” series is calculated by summing the total emissions from the power plants located in Massachusetts’ borders. The emissions in this category are primarily made of up those generated by power plants affected by 310 CMR 7.74, but includes emissions from other unaffected plants as well.
- The light blue “imported emissions” series is calculated via an algorithm which seeks to approximate the one used by Massachusetts DEP in its GHG emissions inventory.[168] Briefly, imported emissions are equal to total imported load multiplied by a marginal emissions rate, where the marginal emissions rate is the rate defined in Section 8.2: *Applying non-embedded costs*, and total imported load is estimated by subtracting the sum of the generation from in-state emitters and purchased RECs (and REC-like instruments) from the projected Massachusetts load.

Table 55 summarizes the degree to which the electric sector complies with the electric sector sublimit (overcompliance is shown with positive numbers and non-compliance is shown with negative numbers).

[168] See https://www.mass.gov/lists/massdep-emissions-inventories for more information.

Figure 31. Modeled Massachusetts emissions in Counterfactual #1, compared to electric sector sublimits

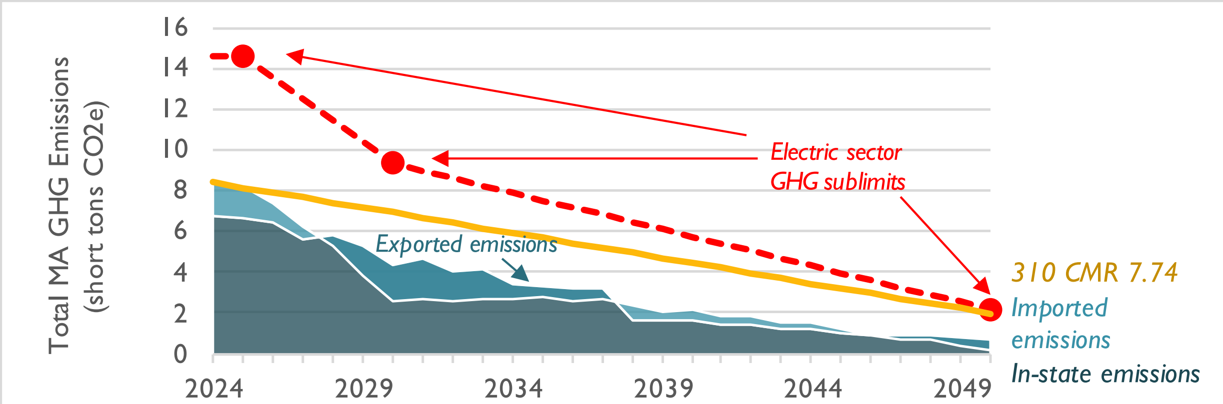


Table 55. Difference in electric sector GHG emissions, compared to electric sector sublimits (million short tons CO_2e)

	CF #1	CF #2	CF #3	CF #4	CF #5	CF #6
2024	6.0	5.5	6.0	6.1	6.1	6.1
2025	6.4	7.3	6.3	6.5	6.5	6.5
2026	6.2	6.9	6.0	6.3	6.3	6.3
2027	6.2	6.7	6.0	6.3	6.3	6.3
2028	6.2	5.2	5.9	6.2	6.2	6.2
2029	6.5	6.3	6.5	6.6	6.6	6.6
2030	6.8	6.6	6.7	6.8	6.8	6.8
2031	6.3	6.1	6.2	6.4	6.4	6.4
2032	6.1	6.1	6.0	6.1	6.1	6.1
2033	5.6	5.7	5.4	5.6	5.6	5.7
2034	5.2	5.4	5.0	5.1	5.1	5.3
2035	4.8	4.9	4.6	4.9	4.8	4.8
2036	4.6	4.9	4.4	4.7	4.6	4.7
2037	4.1	4.7	4.0	4.4	4.3	4.3
2038	4.1	4.3	3.7	4.0	4.1	3.9
2039	4.0	4.2	3.9	4.1	4.1	4.0
2040	3.6	3.8	3.5	3.7	3.7	3.5
2041	3.6	3.7	3.4	3.5	3.7	3.4
2042	3.1	3.3	3.1	3.1	3.3	3.0
2043	3.1	3.3	3.1	3.2	3.3	3.0
2044	2.8	2.9	2.7	2.8	2.9	2.7
2045	2.8	3.0	2.8	2.8	2.9	2.6
2046	2.7	2.9	2.7	2.8	2.8	2.7
2047	2.6	2.7	2.6	2.7	2.7	2.6
2048	2.2	2.4	2.3	2.3	2.4	2.2
2049	2.2	2.3	2.2	2.2	2.3	2.2
2050	2.0	2.2	2.1	2.1	2.2	2.1

Note: Overcompliance with sublimits is shown with positive numbers; undercompliance is shown with negative numbers.

<u>Building sectors</u>

AESC 2024 posits that the mechanisms most likely to achieve compliance with emission reductions required in the residential, commercial, and industrial heating sectors are (a) energy efficiency, (b)

Schedule MM-R1

building electrification, and (c) renewable fuels. We assume that counterfactuals that do not achieve the emission sublimits for these sectors via the first two mechanisms must implement a sufficient quantity of renewable fuels in order to reduce emissions in each year and achieve compliance.[169] Because most modeled counterfactuals do not include quantities of either energy efficiency or building electrification sufficient to meet the sublimit requirements, each counterfactual therefore requires some level of blending of renewable fuels alongside direct fuels (namely natural gas, home heating oil, and propane).

The Synapse Team developed a projection of business-as-usual (BAU) fuel use and emissions in Massachusetts for each fuel type and sector, based on applying growth rates from AEO 2023 to recent historical fuel use data reported by EIA in the SEDS database. For each counterfactual, we then adjust this BAU projection to account for the reduced fuel use (and emissions) achieved via the energy efficiency and building electrification measures that are included. Next, we calculate the amount of renewable fuel blending needed in each year that would achieve emission reductions equal to the remaining gap.[170] Finally, we adjust this blending requirement to reflect any over-compliance or under-compliance in the electric sector.

For example, Counterfactual #1 does not assume any future energy efficiency or building electrification measures beyond that which is installed in 2023; this scenario therefore requires relatively high levels of renewable fuel blending. This level of renewable fuel blending is decreased by the quantity of over-compliance in the electric sector.

Meanwhile, Counterfactual #3 includes large amounts of building electrification. These building electrification measures achieve a large quantity of emission reductions on their own, necessitating a comparatively lower level of fuel blending in order to achieve compliance with the emission sublimits. As with Counterfactual #1, we observe overcompliance with the electric sector sublimits in all years, which helps to reduce the quantity of renewable fuel blending required. This level of renewable fuel blending is decreased by the quantity of over-compliance in the electric sector. Figure 32 illustrates the estimated fuel blending requirements for each counterfactual.

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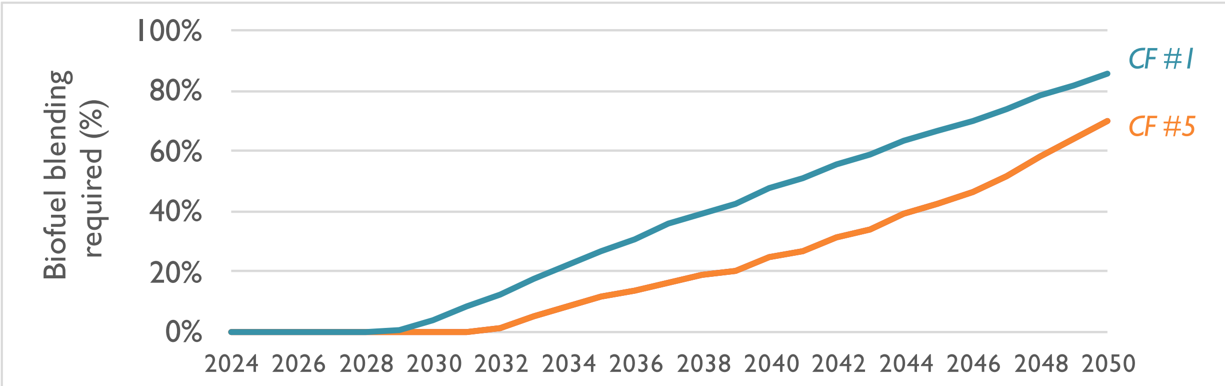
[169] We note that this is the principle underlying the proposed Clean Heat Standard, a policy that is currently under development by Massachusetts Department of Environmental Protection (for more on this topic, see https://www.mass.gov/info-details/massachusetts-clean-heat-standard). As of October 2023, details of a proposed Clean Heat Standard have not yet been made public, although we understand such detail is likely to be issued in 2024. Therefore, the analysis described in this section should be considered an estimation of the likely cost impacts of the coming Clean Heat Standard, without a focus on the specific details of how the policy is likely to be implemented.

[170] As with electric sector emissions, sublimits for the residential heating and C&I heating sectors are only available for 2025, 2030, and 2050. Sublimits for all other years have been linearly interpolated.

Schedule MM-R1

Figure 32. Renewable fuel blending requirements for Counterfactual #1 and Counterfactual #5



Note: In general, counterfactuals that feature building electrification (Counterfactual #3, Counterfactual #4, Counterfactual #6) have projections that closely resemble the projection for Counterfactual #5, will those that do not (Counterfactual #2) resemble Counterfactual #1.

Using the Excel-based versions of AESC 2024's Appendix C and Appendix D, users can calculate the avoided costs for natural gas and fuel oils in Massachusetts both with and without the renewable fuel blending requirements. Generally speaking, these fuel blending requirements increase avoided costs for natural gas and fuel oils (thereby highlighting the relative cost-effectiveness of energy efficiency and building electrification measures, relative to renewable fuels). Using the Excel-based AESC 2024 User Interface, users can also calculate how these blending requirements impact avoided costs associated with non-embedded GHG costs and DRIPE. Generally speaking, including these blending requirements reduces the avoided costs for these categories, as renewable fuels are assumed to have zero (or near-zero) emissions, and are not calculated as having DRIPE benefits.[171] More information on the assumptions related to renewable fuel costs, potentials, and emission rates can be found in Section 2.3: *New England natural gas market* and Section 3.4: *Avoided costs*. More information on the results associated with blending renewable fuels into avoided costs of natural gas and fuel oils can be found in Section 2.5: *Avoided natural gas costs by end* use and Section 3.4: *Avoided costs*.

U.S. EPA's proposed carbon emission rule for fossil-fuel-fired power plants

In May 2023, U.S. EPA released its proposed *Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants* under section 111 of the *Clean Air Act*. Under the proposed rule, different carbon emission abatement pathways are available depending on an affected power plant's retirement date, size, and capacity factor. Table 56 summarizes compliance pathways under 111(d), which regulates existing fossil plants, and Table 57 summarizes compliance pathways under 111(b), which regulates new gas plants (there are currently no planned new coal plants in New England or the United States).

[171] It is likely that eventual large-scale markets for renewable fuels do have DRIPE benefits, but due to the nascent nature of these markets, and the uncertainty in estimating a DRIPE value, we have assumed DRIPE benefits to be zero.

Schedule MM-R1

Table 56. Compliance options for existing power plants under EPA's proposed 111(d) rule

Unit Type	Retirement Date	Compliance Pathway
Coal and Oil/Gas Steam	Before 2032	Plants must not exceed current emissions rate
	After 2032 but before 2035	Capacity factor must be less than or equal to 20% in 2030; must not exceed current emissions rate
	After 2035 but before 2040	Units must co-fire natural gas at 40% of heat input in 2030
	After 2040 or no announced retirement date	Units must have 90% CCS in 2030; wet FGD and ELG also required
Gas GTs and CCs with capacity > 300 MW and future capacity factor > 50%	-	Path A: 90% CCS by 2035 Path B: Combust 30% H_2 by volume by 2032, 96% H_2 by 2038
All other gas-fired GTs and CCs	-	No controls needed

Table 57. Compliance options for new gas plants under EPA's Proposed 111(b) rule

Unit Type	Capacity Factor Cap	Compliance Pathway
Peaking (likely GTs)	20%	No controls needed (emissions rate equal to efficient plant in 2023)
Intermediate (CCs and GTs)	50%	Combust 30% H_2 by volume by 2032
Baseload (likely CCs only)	-	Combust 30% H_2 by volume by 2032, 96% H_2 by 2038

In New England's existing fleet of fossil plants, there are 13 gas-fired combined combined-cycle units that may be affected by the proposed 111(b).[172] For each of these units, we allow the model to optimize between Path A (CCS) and Path B (hydrogen blending) outlined in Table 56. There are no coal plants expected to be impacted by 111(b), and there are unlikely to be any simple-cycle combustion turbines that would be affected by 111(b).[173]

[172] Each of these units has a capacity equal to or greater than the 300-MW threshold stated in EPA's proposed rule. Many, but not all of the units, have a historical capacity factor greater than the 50 percent capacity threshold. If these plants exceed a capacity factor of 50 percent in the relevant years, they will incur compliance requirements.

[173] We note that Canal 3 is likely the only simple-cycle combustion turbine that exceeds EPA's size threshold; but given its relatively low historical capacity factor (about 5 percent), it is unlikely to incur any compliance requirements.

Table 58. List of existing gas plants subject to proposed 111 rules

Plant Type	Plant Name	ORSPL	Unit ID	Plant State	2021 Capacity (MW)	2021 Capacity Factor (%)	Likely to trigger 111 compliance based on 2021 operation?
Combustion Turbine	Canal	1599	3	MA	330	5%	No
Combined Cycle	Millennium Power	55079	CT01	MA	335	24%	No
Combined Cycle	Granite Ridge	55170	CT11	NH	339	53%	Yes
Combined Cycle	Granite Ridge	55170	CT12	NH	339	55%	Yes
Combined Cycle	Fore River Generating Station	55317	GT11	MA	364	52%	Yes
Combined Cycle	Fore River Generating Station	55317	GT12	MA	362	58%	Yes
Combined Cycle	CPV Towantic Energy Center	56047	CTG1	CT	389	81%	Yes
Combined Cycle	CPV Towantic Energy Center	56047	CTG2	CT	390	82%	Yes
Combined Cycle	Kleen Energy Systems Project	56798	U1	CT	311	43%	No
Combined Cycle	Kleen Energy Systems Project	56798	U2	CT	311	46%	No
Combined Cycle	Bridgeport Station	568	501	CT	576	73%	Yes
Combined Cycle	Salem Harbor Station NGCC	60903	3	MA	339	11%	No
Combined Cycle	Salem Harbor Station NGCC	60903	4	MA	338	14%	No

Notes: This table shows only the combustion turbine components of any combined cycle plants. Each of these rows has been allocated a share of the capacity and generation at the local steam recovery units, based on 2021 data from EPA's NEEDS database and EIA 923. Units at Merrimack and Mystic Generation are not shown, as these units are assumed to retire in May 2026 and June 2024, respectively (see Table 45 and Table 47). All plant attributes used in identifying which plants are likely to be subject to 111 is based on EPA's April 2023 edition of the NEEDS database, available at https://www.epa.gov/system/files/documents/2023-04/NEEDS%20for%20EPA%20Post-IRA%202022%20Reference%20Case.xlsx. *Plants are flagged as "likely to trigger 111 compliance based on 2021 operation" if they have a capacity factor higher than 50 percent.*

New gas plants that operate with a capacity factor greater than 20 percent will eventually require either some amount of hydrogen blending or CCS equipment. Both of these technologies have significant cost uncertainties.

For the hydrogen-enabled plants, we use an exogenous hydrogen price trajectory and do not model hydrogen production explicitly (see projection developed in Section 2.3: *New England natural gas market*). Our modeling does not dynamically model electrolyzers and the incremental renewable energy required to produce the hydrogen, but rather integrates all costs into the hydrogen fuel price trajectory. If we were to dynamically model hydrogen, we would need to calculate a shadow price of hydrogen which would vary by scenario (depending on electricity prices and electrolyzer utilization). Using a set

Schedule MM-R1

price trajectory allows us to be consistent across scenarios, and with other avoided fuel cost calculations.

For new and existing baseload gas plants that install CCS, we model all relevant retrofit costs, CO_2 transportation and storage costs, and parasitic load effects associated with operating CCS equipment, as well as the IRA section 45Q tax credits available to powerplants that capture CCS.

For both hydrogen blending and CCS, we use the same retrofit cost assumptions used by the EPA to analyze the impact of its proposed rule through its Regulatory Impact Analysis.[174]

EPA is currently accepting comments on the proposed rule and expects to publish a final rule by summer 2024. The rule may be challenged on the grounds that the proposed systems of emission reduction have not been "adequately demonstrated" as required under Section 111 of the *Clean Air Act*. However, the current policy environment, including the IRA 45Q tax credit for capturing CO_2 and the IRA 45V tax credit for producing hydrogen, will likely lend support to arguments in favor of the economic feasibility of these measures. Generator owners and operators will face decisions now regarding whether to retire fossil units and how to plan for future generation. If the judicial review ends up taking a few years, the regulatory uncertainty may be great enough to cause operators to retire sources early and begin planning their systems assuming the rule will go through regardless of the final outcome.[175]

Inflation Reduction Act and Bipartisan Infrastructure Law

The IRA and Bipartisan Infrastructure Law (BIL) were passed in August 2022 and November 2021 respectively. Both laws allocate substantial federal funding to accelerate the energy transition over the next decade. The tax credits in the IRA begin to phase out after 2032, if and only if the U.S. electric sector emissions reach 25 percent of 2022 levels. We assume that the tax credits remain in effect throughout the study period. The most relevant elements of these laws for the AESC modeling will be:

1. **Tax credits for renewable energy resources:** Applicable IRA tax credits are included in the methodology for projecting renewable energy builds (see Chapter 7. *Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies* for more information).

2. **Tax credits for hydrogen production and CCS:** We assume IRA hydrogen production tax credits are represented in the projected hydrogen fuel price trajectory. Power plants that capture CO_2 receive commensurate IRA tax credit amounts.

3. **Tax credits for nuclear power production:** We assume the IRA 45U zero-emission production tax credit for existing nuclear powerplants prevents the two nuclear

[174] EPA. *Regulatory Impact Analysis.* Docket EPA-HQ-OAR-2023-0072. Available at: https://www.regulations.gov/document/EPA-HQ-OAR-2023-0072-0007.

[175] Clements, Carter. 2023 "Expect Legal Challenges to New EPA Rules on Emissions". *Power Magazine.* Available at: https://www.powermag.com/expect-legal-challenges-to-new-epa-rules-on-emissions/

Schedule MM-R1

powerplants in New England (Seabrook and Millstone) from retiring during our study period.

4. **Funding for energy efficiency and electrification measures:** This funding has the potential to impact future load. All of our assumptions are based on the most recent data from ISO New England, which to our best understanding does not currently include impacts any impacts from IRA or BIL.[176] Because most states in New England already have ambitious energy efficiency and electrification plans, it is unclear whether the IRA funding would lead to different amounts of energy efficiency and electrification, or whether this funding would instead decrease realized costs for consumers. Meanwhile, for electric vehicles, we observe that recent studies analyzing the impact of the IRA suggest that, with IRA funding, electric vehicle sales shares might reach levels of about 50–60 percent in the early 2030s.[177] Using a standard adoption S-Curve and typical rates of vehicle turnover, that implies electric vehicles make up about 20–30 percent of vehicle stock by the early 2030s and reach close to 100 percent stock by 2050. This resembles the forecasts that ISO New England have assembled for the six states in its CELT 2023 forecast, which are used in this AESC analysis.[178]

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[176] Because of limitations in this study's scope and budget, we do not include further impacts on load related to IRA or BIL.

[177] *Analyzing the Impact of the Inflation Reduction Act on Electric Vehicle Uptake in the United States*. Slowik et. al. ICCT and Energy Innovation. January 2023. Available at https://theicct.org/wp-content/uploads/2023/01/ira-impact-evs-us-jan23.pdf.

[178] See Section 4.3: *New England system demand and energy components* for more information on these forecasts.

Schedule MM-R1

5. AVOIDED CAPACITY COSTS

AESC 2024 develops avoided capacity prices for annual commitment periods starting in June 2024. The avoided capacity costs are driven by actual and forecasted clearing prices in ISO New England's FCM. The AESC 2024 forecast prices are based on observations made in recent auctions as well as expected future changes in demand, supply, and market rules. Synapse applies these prices 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).[179] This chapter discusses the methodology for calculating avoided capacity prices through May 2028. We also include discussion of our assessments of avoided capacity costs and cost drivers after 2028, when we assume new market rules will come into effect.

In general, we find that capacity prices are similar to those projected in AESC 2021. Counterfactuals with higher peaks tend to have higher capacity prices than other counterfactuals, although this is impacted by the exogenous resource additions assumed for that scenario. AESC 2024's Counterfactual #1 features higher capacity prices than its AESC 2021 counterpart, in part due to a deferral of clean energy resources (compared to the assumptions used in AESC 2021). Counterfactuals that are missing programmatic demand response resources or programmatic BTM storage have less exogenous firm capacity. Therefore, they have lower near-term reserve margins, and higher near-term capacity prices, compared to counterfactuals with the same respective load components. Eventually, these higher capacity prices lead to incremental endogenous gas and battery storage additions in the mid 2030s, beyond what gets added in the equivalent load counterfactuals with the exogenous firm capacity present. Each single gas plant that gets added provides a large amount of firm capacity, and results in larger reserve margins than might be observed if gas plants were not large, discrete resources. This capacity overbuild that occurs in the mid-2030s drives down longer-term capacity market prices towards the end of the study period for these counterfactuals.

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 through FCA 18, as well as key input assumptions.

[179] "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.

Schedule MM-R1

Avoided capacity methodology through May 2028

This section describes the methodology, data, and sources used to estimate avoided capacity costs for the near-term years in AESC 2024, i.e., costs from 2024 through 2028. The methodology used to estimate avoided capacity costs in later years is found in the subsequent section.

Description of Forward Capacity Market analysis

AESC 2024 develops avoided capacity prices from the FCM auction prices for power-years from June 2024 through May 2027, using data from recently conducted auctions (FCAs 14 through 17, for delivery years 2023/2024 through 2026/2027). For FCA 18, AESC 2024 assumes*:*

- ISO New England will continue to operate the FCM in a manner similar to recent years, including using a similarly shaped demand curve.
- Resources generally continue to bid FCM capacity in a manner similar to their bidding in recent auctions. 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.
- Following recent trends, prices in different zones within New England will not separate in price. 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 owners and ISO New England have made great efforts to eliminate binding capacity constraints between zones and have been successful since FCA 10.[180] We observed relatively minimal price separation in FCA 15 and FCA 16, but the price differences were small and did not exist in FCA 17, so we assume no price separation in FCA 18 for simplicity. Further, we do not anticipate sufficient new resources (such as offshore wind) to enter the market in FCA 18 to lead to significant price separation in just a single year, especially given that many offshore wind resources are planned to interconnect in SEMA, which has traditionally been import constrained rather than export constrained.
- 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 17.
- 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 or that clear through the Renewable Technology Resource

[180] 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.

(RTR) exemption, and imports. In FCA 18, market rules set minimum offer prices for resources of each technology type that can limit the ability of new state-sponsored resources to clear. However, the RTR exemption allows these resources to bypass minimum offer prices and nearly 600 MW of RTR exemption is available for FCA 18. Alternatively, new resources can enter the market through a secondary auction called Competitive Auctions with Sponsored Policy Resources or CASPR, in which new resources can substitute for existing resources but at lower prices. However, no resources have participated in CASPR in recent years, and we do not expect that to change in FCA 18, particularly given the substantial amount of capacity available in the RTR exemption.

- For purposes of simplification, we assume that all resources are paid a single-year price, rather than a multi-year price. The option for new resources to elect a multi-year price was removed beginning in FCA 16.[181]

Input assumptions to FCM analysis

The analysis of future capacity prices utilizes the results of the four most recent auctions (FCA 14 through FCA 17), which are among the only ISO New England FCAs to clear at bid prices, rather than an administrative limit.[182] Table 59 shows the Rest of Pool 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.

[181] 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.

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

Schedule MM-R1

Table 59. FCA price results by round (Rest-of-Pool results only)

			CONE	Net CONE	Round 1	2	3	4	5
FCA 14	Price	*2024 $/kW-month*	$11.73	$8.37	$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	*2024 $/kW-month*	$11.95	$8.71	$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
FCA 16	Price	*2024 $/kW-month*	$12.13	$7.31	$8.42	$5.49	$2.55	$2.53	$8.42
	Demand	*MW*			31,471	31,986	32,803	33,053	31,471
	Excess	*MW*			4,488	3,973	3,115	0	4,488
	Supply	*MW*			35,959	35,959	35,918	33,053	35,959
FCA 17	Price	*2024 $/kW-month*	$12.21	$7.04	$8.22	$5.35	$2.48	$2.48	
	Demand	*MW*			30,133	30,602	31,370	31,601	
	Excess	*MW*			4,547	4,036	3,053	0	
	Supply	*MW*			$8.22	$5.35	$2.48	$2.48	

Notes: All prices have been converted to 2024 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.

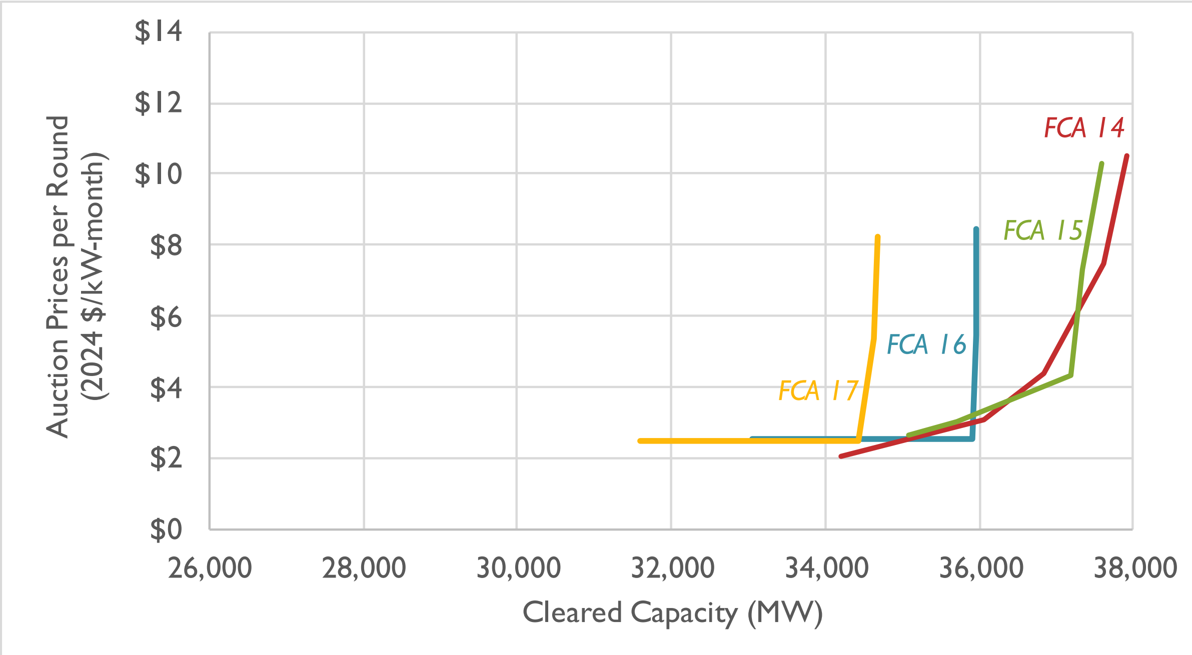
Historical supply curves

Figure 33 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. We note that in the most recent auctions, the supply curve has tended to create a "reverse L" shape, with one very shallow line segment, and one very steep line segment.

The price curves for the last four auctions are relatively closely clustered and guide the AESC 2024 projection for future pricing. For future years, we move the FCA 17 supply curve right or left to reflect changes in capacity additions and retirements under each counterfactual.

Schedule MM-R1

Figure 33. FCA price results by round (effective supply curves)



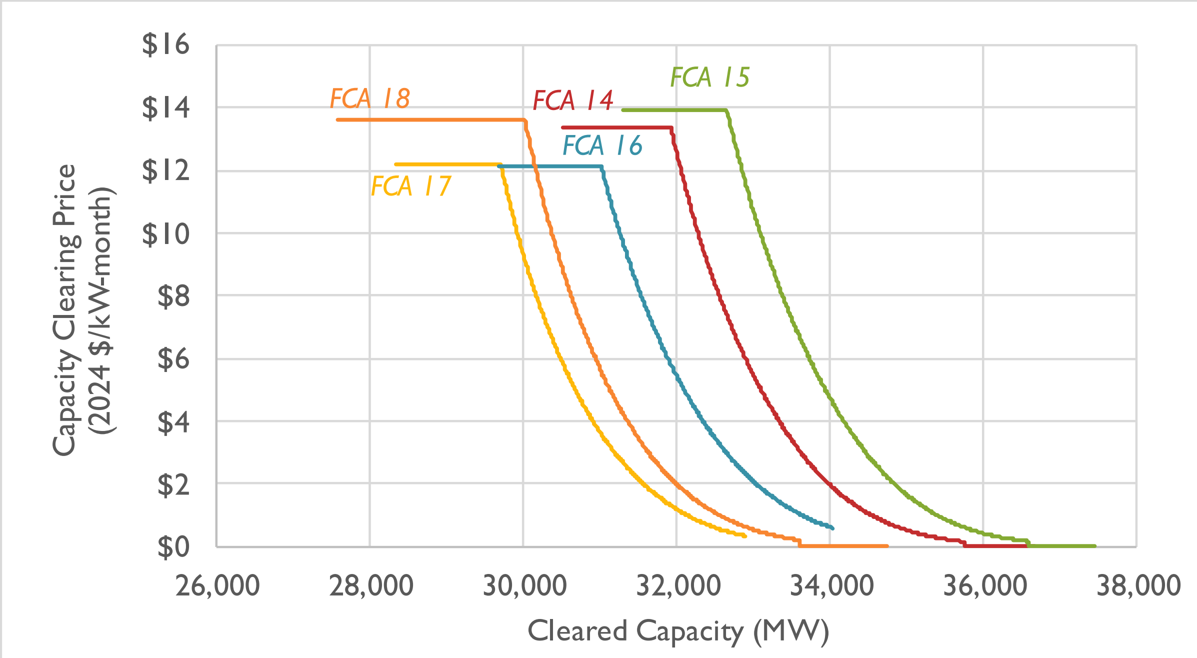
Note: All prices have been converted into 2024 dollars. Values shown for Rest-of-Pool only.

<u>Historical demand curves</u>

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 34 shows demand curves used in FCA 14 through 17. To model FCA 18, we rely on the demand curve for FCA 18 published by ISO New England, shifted according to projected changes in demand in each counterfactual.

Figure 34. Recent FCA demand curves



Note: All prices have been converted into 2024 dollars. Values shown for Rest-of-Pool only.

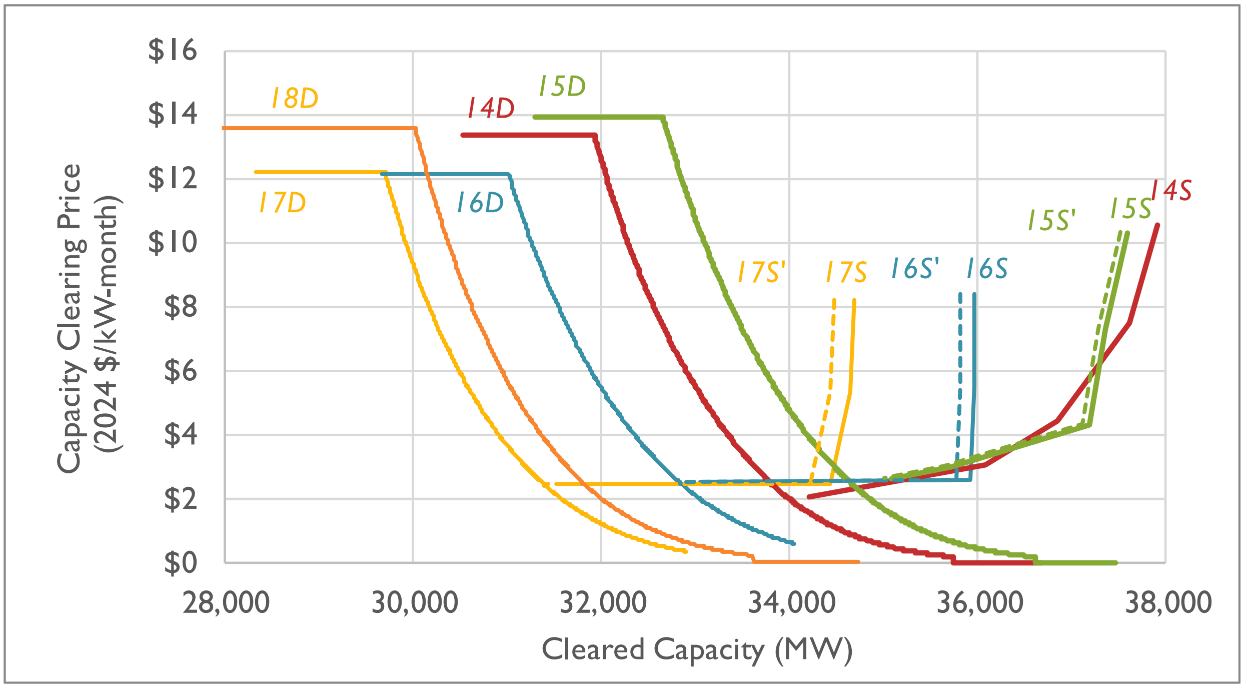
Historical capacity price results

Figure 35 shows the result of matching the demand and supply curves for FCA 14 through FCA 17. 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 solid line representing the supply curve for each FCA
- A dashed line for the supply curve for Counterfactual #1 that excludes the post-2024 energy efficiency for each FCA

Schedule MM-R1

Figure 35. Market clearing capacity prices for FCA 14 through FCA 17



Notes: Solid lines marked "D" are demand curves, solid lines marked "S" are actual supply curves, and dashed lines marked "S'" are supply curves absent post-2023 energy efficiency. Intersections of "S" and solid "D" lines denote the clearing price under actual conditions while intersections of "S" and dashed "D" lines denote what the clearing price would have been but for post-2023 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. Table 60 summarizes the clearing prices for the actual and hypothetical "without post-2020 EE" cases described in Figure 35. Because recent auctions have tended to clear at very flat parts of the demand curve, adding more energy efficiency tends to have a very minor impact on prices.[183]

Table 60. Capacity prices for recent and pending FCAs (2024 $ per kW-month)

Commitment Period (June to May)	FCA	Actual Clearing Price	Actual Clearing Price Without post-2023 EE
		2024 $	*2024 $*
2023/2024	14	$2.05	$2.05
2024/2025	15	$2.61	$2.66
2024/2025	16	$2.53	$2.53
2025/2026	17	$2.48	$2.48

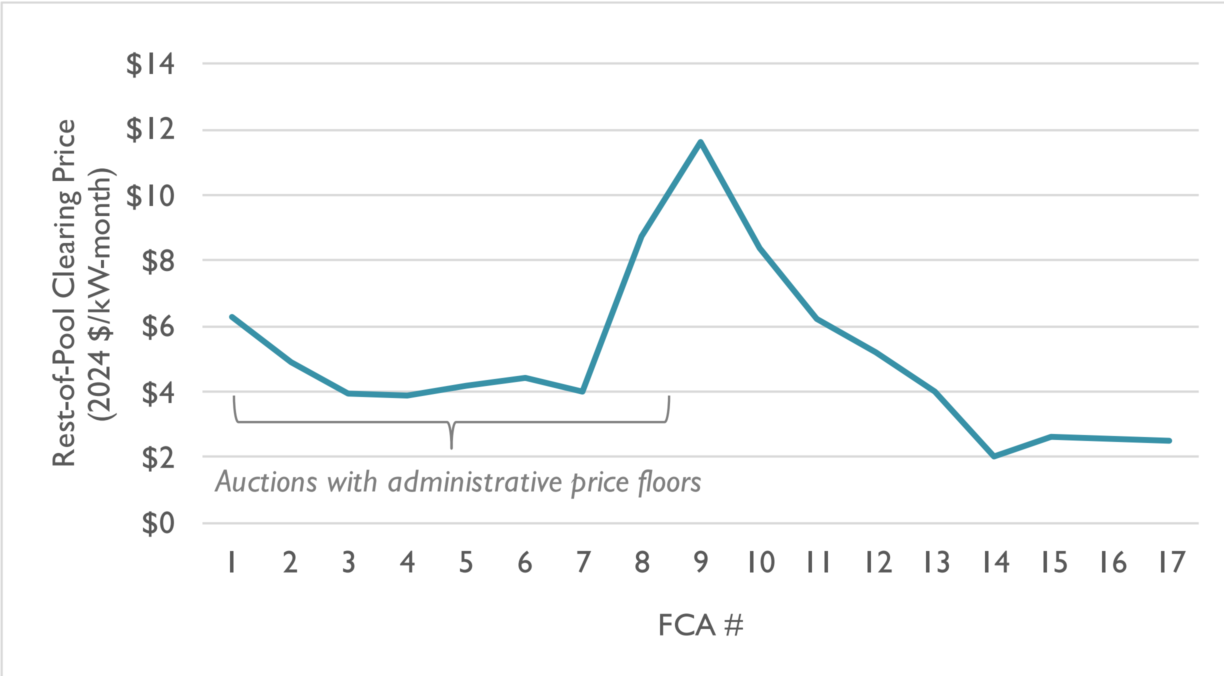
Note: Values shown are for Rest-of-Pool only.

[183] As of the time of this document's publication, FCA 18 has been conducted, but no price results have been made public.

Schedule MM-R1

As a point of reference, Figure 36 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 $2.45 kW-month.

Figure 36. Forward capacity auction clearing prices for all past auctions (Rest-of-Pool prices only)



Note: All prices have been converted into 2024 dollars.

<u>Regional capacity price separation</u>

The sections above describe the methods for calculating capacity prices for the Rest-of-Pool only. However, FCA 15 and FCA 16 displayed regional price separation, or a difference in capacity clearing prices resulting from additional supply and demand constraints in some regions of ISO New England relative to the rest-of-pool region. Specifically, Southeast New England (SENE) and Northern New England (NNE) separated in price from the Rest-of-Pool in each of these auctions.

ISO New England does not make the SENE or NNE supply curves public, so we are not able to use the methods described earlier. Instead, we rely on the public MRI demand curves for each region to determine an estimate of capacity prices for counterfactuals that remove energy efficiency. We identify where along the demand curve the market cleared for each region, remove the relevant quantity of energy efficiency, and determine the modified clearing price for each. Because the market clears where the supply and demand curves intersect, this approach results in the same outcome as using the supply curve had that been available. The location of this clearing price also informs capacity DRIPE, which we derive based on the slope of the supply curve where the clearing price occurs.

Schedule MM-R1

Projecting future capacity prices

For FCA 18, we estimate the supply curve, using the steps described above. The demand curve has already been published by ISO New England. The supply curve shifts left or right, depending on the extent of resource retirements and additions.[184] The intersection of these two curves indicates the capacity price.

Table 61 depicts the available supply under each counterfactual in the future years where prices are simulated (as opposed to FCAs 14 through 17, 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.* The supply depicted here is the net cumulative supply relative to FCA 17, after accounting for those inputs, as well as endogenous conventional plant retirements and additions. We model about 3.8 GW of additional firm capacity in Counterfactual #1 and #5. Few differences are present between counterfactuals due to the fact that most capacity changes between now and 2027 are already known. In addition, there are few differences in peak demand between the counterfactuals in this early time period, which minimizes the likelihood of the model selecting different capacity builds by 2027. See Chapter 6: *Avoided Energy Costs* for more discussion on these results.

Table 61. Projected cumulative change in supply (GW), relative to FCA 17

		Counter-factual #1	Counter-factual #2	Counter-factual #3	Counter-factual #4	Counter-factual #5	Counter-factual #6
FCA 18	2027/2028	3,913	3,981	3,995	3,913	3,995	3,852

As described above, our simplified capacity market model does not estimate geographic price separation in FCA 18. We observe relatively minimal price separation in FCA 15 and FCA 16, no price separation in FCA 17, and we assume no price separation in FCA 18 to be consistent with those recent trends. Although it is possible that price separation could occur, there is much uncertainty in terms of where this separation could occur and what level of price spread occurs.[185] Thus, for purposes of simplicity, we assume a single regional clearing price for FCA 18.

<u>FCA 18 results</u>

As described above, for each year and each counterfactual, MW differences in supply (relative to FCA 17) are added to or subtracted from the FCA 17 supply curve to create a new estimated FCA 18 supply

[184] 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.

[185] We observe that future interconnection of large generators in regions that currently lack them (e.g., offshore wind installations in southeast Massachusetts or Rhode Island) may produce future price separation. However, the degree to which this price separation would occur is uncertain and challenging to predict.

curve. On the demand side, we use the FCA 18 demand curve published by ISO New England, modified to include new energy efficiency per the inputs relevant to each scenario. Table 62 describes the resulting market clearing prices in Counterfactual #1 for FCA 18, showing a clearing price of $2.48 per kW-month. We observe that this value resembles the clearing price from FCA 17, as a result of the overall similarity in demand curves and very flat shape of the supply curve. Results for other counterfactuals are similar, due to the same dynamics described above.

Table 62. Projected capacity prices for FCA 18 (2024 $ per kW-month)

		Counter-factual #1	Counter-factual #2	Counter-factual #3	Counter-factual #4	Counter-factual #5	Counter-factual #6
FCA 18	2027/2028	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48

Note that FCA 18 was conducted on February 5, 2024. As of the time of this document's publication, but no price results have been made public. As a result, the results of this auction were not available to be included in the AESC 2024 analysis.

Avoided capacity methodology for June 2028 and later

This section describes the methodology, data, and sources used to estimate avoided capacity costs for the longer-term years in AESC 2024, i.e., costs in June 2028 and later.

In AESC 2024, we model the capacity market within the EnCompass model, the same model used to develop avoided energy prices. This change allows us to incorporate updated ISO market rules and to better align our capacity analysis with our energy analysis and modeling. The new methodology offers the following advantages:

- It is consistent with modeled energy prices because both would be calculated using the same model results (cost inputs are described above in Section 4.5: *Anticipated non-renewable resource additions and retirements*).
- Future supply curves are modeled based on the changing resource mix.
- Dynamic resource accreditation values are captured, including changes to the accreditation values of existing resources that remain in the supply stack from one year to the next. The methodology is described in more detail below.
- Capacity price separation associated with transmission constraints is endogenously modeled based on existing transmission constraints within EnCompass.

Background

ISO New England is proposing a major capacity market reform through the RCA project. RCA will replace the existing heuristic-based accreditation system with a more sophisticated but complicated probabilistic assessment called the Resource Adequacy Assessment (RAA). The RAA simulates thousands

Schedule MM-R1

of possible years with different weather patterns and resource performance outcomes based on available historical data. The RAA identifies simulated hours in which some load would go unserved. The RCA project proposes to accredit resources based on their marginal impact on the amount of unserved energy over the thousands of simulated years. This quantity is defined as the Marginal Reliability Impact (MRI). The MRI approach aligns resource accreditation with the calculation of the Installed Capacity Requirement (ICR) that anchors the demand for capacity in the FCM. MRI values are normalized relative to the MRI of a perfect capacity resources that is available at all hours of the year without any outages or operational limitations. The result is the relative MRI (rMRI) value, which when multiplied by Qualified Capacity (QC) gives the accredited capacity value, called the Qualified MRI Capacity (QMRIC).[186] Notably, under the MRI approach, resource accreditation values depend on the resource mix and can change every year. This increases the complexity of modeling capacity market outcomes.

The RCA project also includes updates to how the RAA process accounts for fuel supply limitations. Historically, fuel supply was modeled without limits such as natural gas pipeline constraints and fuel oil tank replenishment timelines. As part of RCA, ISO proposes to model limits on available gas supply. These limits would be based on gas pipeline import capability in addition to forecasted LNG supply. These new limits on fuel availability would reduce the accreditation values of gas-only resources in the winter. Preliminary analysis that the ISO has conducted has shown minimal reliability risks in the winter when gas pipeline constraints tend to be binding. However, ISO is still considering adjustments to how it models fuel oil replenishment that could shift modeled risk toward the winter months and increase the impact of ISO's proposed gas modeling updates. In the future, increasing winter loads associated with electrification could increase modeled winter risk too.

ISO is also seriously considering adopting a seasonal and/or prompt capacity market design.[187] In a seasonal market, resources would be accredited, and demand would be calculated separately for each season (such as summer or winter). In a prompt market, the capacity auction would be held shortly before the associated Capacity Commitment Period (CCP). While both market design changes are significant, a move to a seasonal market would have a particularly large effect on the AESC 2024 capacity modeling methodology.

Methodology for AESC 2024

Given the significant uncertainty regarding the future capacity market design in New England, we model a seasonal capacity market, due to the stated interest of ISO New England in adopting such a design, the increasing popularity of seasonal market designs in other RTOs and ISOs (NYISO and MISO have seasonal

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[186] ISO New England. July 12, 2022. "Resource Capacity Accreditation in the Forward Capacity Market." Page 34. Available at: https://www.iso-ne.com/static-assets/documents/2022/07/a02a_mc_2022_07_12-14_rca_iso_presentation_conceptual_design.pptx.

[187] ISO presented on the tradeoffs associated with a seasonal and/or prompt capacity market at the August NEPOOL Markets Committee meeting. ISO New England. *Tradeoffs with Alternate FCM Commitment Horizons*. August 8-10, 2023. Available at https://www.iso-ne.com/static-assets/documents/2023/08/a03a_mc_2023_08_08-10_prompt_seasonal_tradeoffs_presentation.pdf.

Schedule MM-R1

markets, and PJM is considering one), and the ability of seasonal results to be aggregated back up to annual results if necessary.

EnCompass simulates the capacity market by approximating an auction that includes an administrative demand curve and a supply curve made up of all resources that remain operating in each year. The administrative demand curve is specified using three points, which in turn are each designated by a price and a reserve margin (relative to the peak load). The full demand curve is made by connecting these three points with two line segments, which approximates the smooth demand curve that ISO New England uses in its market. The supply curve is based on resource accredited capacities and offer prices.[188] Resources are ordered based on their input offer prices, which are calculated as the difference between their avoidable costs (fixed costs plus new resources' levelized capital costs, as described above in Section 4.5: *Anticipated non-renewable resource additions and retirements*) and their operating profits (energy revenues minus fuel and other variables costs). Each resource contributes an amount of capacity to the supply curve equal to its accredited capacity. EnCompass determines where the administrative demand curve and the supply curve intersect and sets the capacity price at that point. EnCompass can simulate a capacity auction as described in this section either on an annual basis or more frequently (such as on a seasonal basis). The primary inputs into EnCompass's capacity market modeling are the individual resource accreditation values and the regionwide reserve requirements.

To account for the changing accreditation values and demand requirements, we develop forecasts of accreditation values and reserve margins that depend on the resource mix, using an iterative modeling approach. This approach evaluates accreditation values by conducting Monte Carlo simulations in EnCompass based on stochastic load and generation data published by ISO New England.[189] Within this approach, Monte Carlo simulations have been conducted for 2030, 2040, and 2050 to benchmark reserve margin and accreditation values as the resource mix and load profile changes. We calculate accreditation values for the remainder of the study period years by interpolating between these three benchmark years. For each year, we model a base case to determine baseline unserved energy and then model additional scenarios with 1 MW of each renewable and storage resource type (as well as perfect capacity) added to calculate each resource type's impact on unserved energy, and ultimately to calculate accreditation values. Meanwhile, we calculate reserve margins by summing the amount of accredited capacity needed for the system to achieve 1 in 10 LOLE. We then input calculated reserve margin and accreditation values from the Monte Carlo analysis into the primary EnCompass avoided cost runs for each counterfactual, which shifts the resource mix. Next, we iterate between the Monte Carlo accreditation runs and the deterministic avoided cost runs until the results converge.

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188 More information on supply and demand curves can be found later in this chapter on page 138 and following.

189 ISO New England. 2022. Variable Energy Resource Data. Available at: https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data/.

Schedule MM-R1

Post-May 2028 avoided capacity modeling results

As soon as the seasonal market begins to be modeled in 2028, the capacity prices in summer and winter diverge. Because there is more load in the summer in Counterfactual #1, and the availability of most resources on the system is similar in the summer and the winter, summer is the season that results in more risk of generation shortages. As a result, more capacity is required in the summer to achieve the same reliability target, and when enough capacity is procured for the summer, excess is available in the winter. This leads to $0 per kW-month capacity prices in the winter in our modeling. We note that our modeling does not currently capture limitations to gas and oil availability in the winter that ISO New England is planning to incorporate into the RCA accreditation framework, though it is still uncertain how large of an effect those constraints will have.

Because post-2028 capacity prices are calculated endogenously in the EnCompass model, we perform a number of post-processing steps to extract detail related to price shifts and reliability metrics, which we use to estimate capacity DRIPE values and values of reliability. The following sections provide methodology on how we perform these calculations.

Calculating demand curves

In AESC 2024, we model the capacity market endogenously within EnCompass. This requires the construction of a capacity demand curve that can be entered into the EnCompass model and used as a constraint. ISO New England uses an MRI demand curve to procure capacity in the FCM on behalf of load. While ISO New England's RCA project will impact the shape and position of the demand curve, ISO New England is proposing to largely maintain its MRI methodology for developing the demand curve. That MRI methodology involves calculating a Net ICR that anchors the demand curve.[190] The Net ICR represents the amount of capacity needed to exactly achieve 0.1 LOLE. The MRI demand curve is constructed to have a value of Net CONE at the Net ICR capacity quantity. Then, to draw the rest of the curve, ISO New England calculates the MRI of incremental capacity by calculating expected unserved energy (EUE) with different amounts of capacity on the system. The value of the MRI demand curve changes proportionately with the EUE reduction (in hours per year) associated with an incremental MW of capacity at each quantity of system capacity. In its December 2022 presentation to the Markets Committee about the RCA proposal, ISO New England noted that conforming changes would need to be made to the calculation of Net CONE and to the construction of the demand curve to translate both from Qualified Capacity (QC) space to Qualified MRI Capacity (QMRIC) space.[191] Thus, the two anticipated changes are that (1) Net CONE will be recalculated to reflect the new accreditation values

[190] See ISO New England FCM 101 training, Lesson 4: Capacity Zones and Demand Curves. Available at: https://www.iso-ne.com/static-assets/documents/100005/20231024-fcm101-lesson-4-capacity-zones-demand-curves_print.pdf.

[191] Otto, S., and F. Zhao. December 2022. "Resource Capacity Accreditation in the Forward Capacity Market." Slide 12. Available at: https://www.iso-ne.com/static-assets/documents/2022/12/a02a_mc_2022_12_06_08_rca_iso_design_presentation.pptx.

Schedule MM-R1

and (2) the x-axis of the demand curve will be measured in QMRIC (new accreditation) instead of QC (old accreditation).

For the purposes of our analysis, we use Monte Carlo simulations in EnCompass to calculate the Net ICR by determining the amount of load that the resource mix can support at exactly 0.1 LOLE.[192] This Net ICR value then serves as an input into EnCompass's internal capacity demand curve. As described earlier in this chapter, EnCompass simulates the capacity market by approximating an auction that includes an administrative demand curve and a supply curve made up of all resources that remain operating in each year. The administrative demand curve is specified using three points, which in turn are each designated by a price and a reserve margin (relative to the peak load). The full demand curve is made by connecting these three points with two line segments, which approximates the smooth demand curve that ISO New England uses in its market. Note that to make the optimization linear, EnCompass takes the two line segment demand curve and converts it into a step function with five steps per line segment. This results in discretized capacity price results.

The primary inputs into EnCompass' capacity market modeling are the individual resource accreditation values and the regionwide reserve requirements. To account for the changing accreditation values and demand requirements, we develop forecasts of accreditation values and reserve margins that depend on the resource mix, using an iterative modeling approach. This approach evaluates accreditation values by conducting Monte Carlo simulations in EnCompass based on stochastic load and generation data published by ISO New England.[193] Within this approach, we conduct Monte Carlo simulations for 2030, 2040, 2050 to benchmark reserve margin and accreditation values as the resource mix and load profile changes.[194] For each year, we calculate reserve margins by summing the amount of accredited capacity needed for the system to achieve 1 in 10 LOLE. The reserve margins that achieve 0.1 LOLE correspond to the Net ICR, and are thus used to anchor the MRI demand curve.

As shown in Figure 37, we need to specify two additional points along the demand curve in EnCompass: one on either side of the middle point at the Net ICR. To keep the computation feasible within the time constraints of the AESC 2024 study, we do not conduct additional Monte Carlo simulations to select these points. Rather, we use the shape of the FCA 18 MRI curve, anchoring it to the Net ICR values that we calculate for future years under RCA. To determine the point to the left of Net ICR, we use the

192 Note that our analysis includes several simplifications to make the calculations feasible. These include not explicitly calculating the impacts of tie benefits and OP-4 relief in determining Net ICR, and not recalculating Net CONE with the assumption that the reference resource, a new gas combined cycle plant, will not be significantly impacted by RCA. (This last assumption reflects that we do not incorporate winter gas supply limitations in this analysis, though we recognize that ISO is incorporating these limitations and gas CC resources could see reductions in accreditation as a result that would impact Net CONE.)

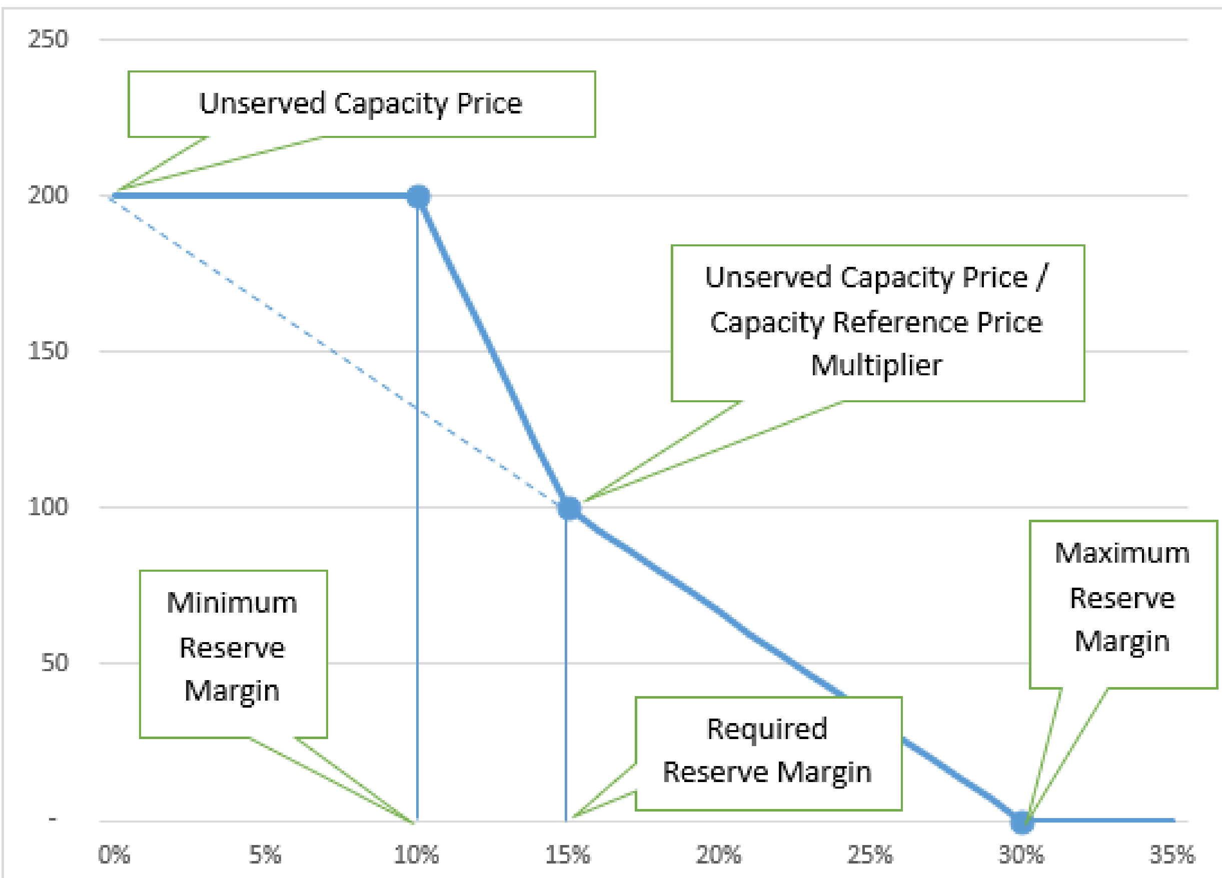
193 ISO New England. 2022. Variable Energy Resource Data. Available at: https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data/.

194 We also explored generating ELCC values for interim years (e.g., 2035 and 2045). We ultimately decided against this due to the similarity in ELCCs between the three years that were modeled.

Schedule MM-R1

rightmost point on the FCA 18 MRI curve at the auction starting price. For FCA 18, this point is at 30,015 MW, or 1.8 percent below the Net ICR value of 30,550 MW. In our modeling, we assume that the demand curve reaches the auction starting price at a capacity quantity that is 1.8 percent below Net ICR. To determine the capacity quantity coordinate of the point to the right of Net ICR on the MRI curve, we use the point at which the FCA 18 demand curve reaches a price of $1/kW-month.[195] To the right of this point, the FCA 18 MRI curve is flat and close to zero. This occurs at a capacity quantity of 32,610 MW, which is 6.7 percent greater than Net ICR. In EnCompass, we specify the third point on the MRI curve to be the point with a capacity quantity coordinate 6.7 percent greater than Net ICR and a price coordinate of $0/kW-month (EnCompass requires the third point along the demand curve to have a price of $0/kW-month). Figure 38 shows an illustrative demand curve as used as an input to AESC 2024, and how it compares with the analogous MRI curve.

Figure 37. EnCompass capacity demand curve inputs

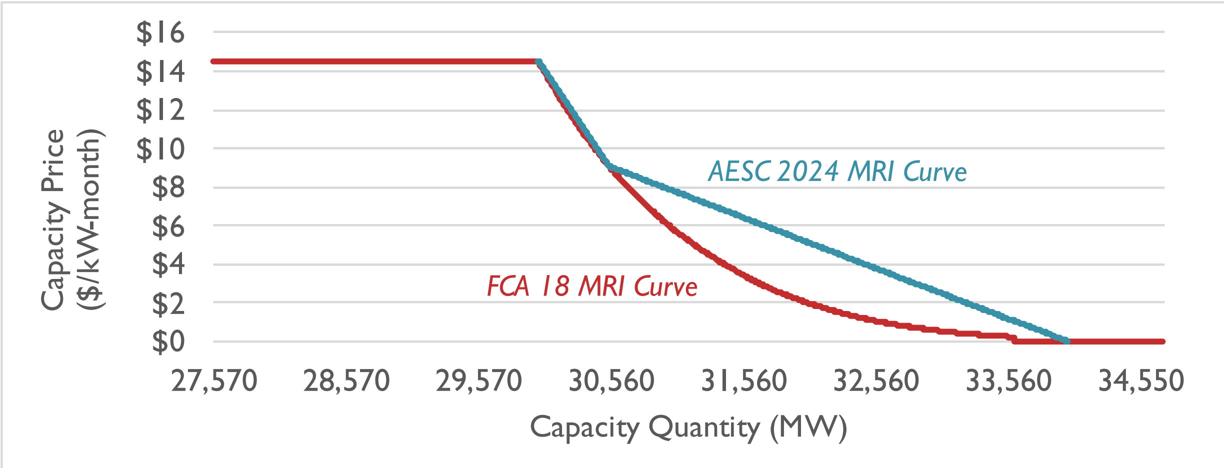


[195] One could conceptualize an alternative approach where this datapoint is more generalized relative to Net CONE (e.g., 90% below Net CONE). The methodology described in the above text was chosen given the time constraints of the AESC 2024 study.

Schedule MM-R1

Source: Reproduced from the EnCompass user guide.

Figure 38. Example capacity demand curve (with unchanged Net ICR) relative to FCA 18 demand curve



<u>Supply curve methodology</u>

To calculate capacity DRIPE, reliability value, and other capacity-related avoided costs, we need to identify the shape of the supply curve. To calculate the supply curve in each season, we take a resource's energy revenues from our modeling results as fixed, and then calculate its capacity bid based on the missing revenue needed to recover all fixed and variable costs. In other words, we subtract energy revenues from fixed costs for each season, and then divide this "missing money" quantity by the resource's accredited capacity in the season.[196] Once each resource's capacity bid is calculated for each season, we can order the resources from lowest to highest offer price to form a supply curve. To calculate the slope of the supply curve at different points along the curve, we estimate the slope over a local portion of the supply curve as specified by a percentile range of total firm capacity in the supply curve.[197]

The EnCompass model's handling of the capacity market and supply curves (which is predicated on the outcome of modeling results) is different than the method used to determine the supply curve in the current auction approach (which is predicated on observations from completed auctions). Under the current auction approach, we have information about all resources that participated in the auction, whether they cleared the auction or not. That supply curve is also based on real data (rather than

[196] Determining static supply curves for capacity is necessary to make the calculation of capacity DRIPE and other related values feasible. However, we note that an incremental 1 MW of energy efficiency would impact energy prices, summer capacity prices, and winter capacity prices all at once, which would cause shifts in the summer and winter capacity supply curves (in addition to the shift along the curve) because energy revenues and other-season capacity revenues impact seasonal resource capacity bids.

[197] Specifically, we look at data points within +/-100 MW of the clearing price (or however close is possible to be estimated given the results of the particular year and counterfactual) and determine an average supply curve slope. This MW spread is used in order to avoid noisy data and to be a better reflection of a portfolio-sized energy impact.

approximate modeled data), reflecting the expected realities of what capacity auction participants think their resources will experience in terms of all electricity market costs and revenues. In contrast, in years for which we depend on EnCompass to estimate capacity prices, we only have data on the resources that actually cleared the auction. In EnCompass, the resources that do not clear the auction retire and therefore do not contribute to the supply curve. Furthermore, our modeled version of this market uses simplified assumptions to estimate energy revenues and costs. Resources that are retained by the model but have higher implied capacity bids are kept running for other non-quantifiable reasons (e.g., if the resource were to retire, capacity prices in that year or some other year would be much higher). Finally, because the model breaks the supply curve into “steps” in order to reduce solve time, it means that the capacity prices are staggered at discrete breakeven points (roughly $2/kW-month). This means that, compared to a model that had a continuous supply cure function, in some years EnCompass may overestimate capacity prices while in other years it may underestimate capacity prices.

Aggregate results

Resulting capacity prices are shown in Table 63. Counterfactuals such as Counterfactual #1 that assume no new energy efficiency measures installed after 2023 rely on an estimation of what capacity prices for the most recent auctions would have been without the inclusion of that energy efficiency. Other counterfactuals, such as Counterfactual #5, assume a continuation of energy efficiency installations and rely on the actual capacity prices. Despite this difference in methods, because recent auctions have tended to clear on very flat parts of the supply curve, there tend to be very only minor differences in results for capacity prices in the near term. These are the avoided capacity costs used for cleared resources.

Prices in Table 63 are shown in units of $ per kW-month, as this is the unit predominantly used in the current capacity market. However, under the future capacity market structure, which is seasonal, it is likely more intuitive to think about prices in $ per kW-season terms. Later tables and figures in this section that focus on the latter years of the study period use this unit instead.

Schedule MM-R1

Table 63. Comparison of capacity prices in Rest-of-Pool (2024 $ per kW-month)

Commitment Period (June to May)	FCA	Actual	Actual but for post-2023 EE	AESC 2024 CF #1	CF #2	CF #3	CF #4	CF #5	CF #6	AESC 2021 CF #1
2024/2025	15	$2.61	$2.66	$2.66	$2.61	$2.66	$2.61	$2.61	$2.61	$3.10
2025/2026	16	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$2.53	$3.07
2026/2027	17	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$3.25
2027/2028	18			$2.48	$2.48	$2.48	$2.48	$2.48	$2.48	$3.51
2028/2029	19			$2.57	$1.42	$1.42	$2.83	$1.42	$4.25	$3.72
2029/2030	20			$2.83	$1.42	$2.83	$4.25	$2.83	$5.66	$4.06
2030/2031	21			$4.25	$1.42	$2.83	$4.25	$2.83	$5.66	$3.86
2031/2032	22			$4.25	$1.42	$2.83	$4.25	$1.42	$5.66	$4.15
2032/2033	23			$5.66	$2.83	$5.66	$5.66	$4.25	$7.08	$4.40
2033/2034	24			$5.66	$2.83	$4.25	$5.66	$2.83	$5.66	$4.36
2034/2035	25			$7.08	$5.66	$5.66	$8.49	$7.08	$4.25	$5.27
2035/2036	26			$5.66	$5.66	$2.83	$7.08	$8.49	$7.08	$4.13
2036/2037	27			$4.25	$4.25	$1.42	$4.25	$7.08	$4.25	n/a
2037/2038	28			$7.08	$5.66	$5.66	$7.08	$7.08	$5.66	n/a
2038/2039	29			$7.08	$7.08	$4.25	$7.08	$7.08	$8.49	n/a
2039/2040	30			$5.66	$5.66	$5.66	$5.66	$7.08	$5.66	n/a
2040/2041	31			$10.53	$5.66	$5.66	$5.66	$9.51	$4.25	n/a
2041/2042	32			$7.08	$5.66	$5.66	$4.25	$8.49	$5.66	n/a
2042/2043	33			$5.66	$4.25	$7.08	$2.83	$9.51	$4.25	n/a
2043/2044	34			$7.08	$5.66	$7.08	$2.83	$9.51	$4.25	n/a
2044/2045	35			$7.08	$5.66	$7.08	$2.83	$9.51	$2.83	n/a
2045/2046	36			$9.51	$7.08	$5.66	$2.83	$8.49	$4.25	n/a
2046/2047	37			$9.51	$8.49	$7.08	$2.83	$7.08	$2.83	n/a
2047/2048	38			$11.94	$8.49	$5.66	$2.83	$5.66	$2.83	n/a
2048/2049	39			$8.49	$8.49	$7.08	$2.83	$7.08	$2.83	n/a
2049/2050	40			$8.49	$5.66	$7.08	$4.25	$9.51	$2.83	n/a
2050/2051	41			$7.08	$5.66	$5.66	$2.83	$7.08	$2.83	n/a
15-year levelized cost				**$4.73**	**$3.60**	**$3.66**	**$5.02**	**$4.51**	**$5.23**	**$3.96**
Percent difference				**19%**	**-9%**	**-8%**	**27%**	**14%**	**32%**	**-**

Notes: Levelization periods are 2024/2025 to 2038/2039 for AESC 2024 and 2021/2022 to 2035/2036 for AESC 2021. Real discount rate is 1.74 percent for AESC 2024 and 0.81 percent for AESC 2021. 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 2024 User Interface. Future costs for Counterfactual (CF) #1 are summer capacity prices, for the months of June through September. Capacity prices for 2028–2050 are weighted four months for summer prices and eight months for winter prices.

Longer term, capacity prices are subject to the seasonal RCA and produce a summer price that is paid for four months and a winter price that is paid for eight months. Table 63 illustrates a series of combined prices, where summer and winter prices are each weighted by the number of months for which they are paid. Counterfactual #1 is summer peaking throughout the study period, but winter peaks approach summer peaks late in the study period to a degree that elicits capacity prices in both seasons. On a 15-year levelized basis, the capacity prices in AESC 2024's Counterfactual #1 are 19 percent higher than

Schedule MM-R1

what was projected in AESC 2021.[198] This is largely due to increases in demand alongside near-term plant retirements (e.g., Mystic and Merrimack), and diminishing ELCCs for clean energy.

Compared to Counterfactual #1, Counterfactual #2's peaks are lower, with more exogenous firm capacity from BTM storage and demand response resources. This extra-firm capacity leads to lower capacity prices. As in Counterfactual #1, winter peaks approach summer peaks late in the study period, with capacity prices for both seasons appearing in the early 2040s.

Meanwhile, Counterfactual #5 experiences a shift from summer to winter peaking in the mid-2030s. It features summer-only capacity prices in the near term, both summer and winter prices in the 2030s, and winter-only prices through 2050. Because capacity prices in the near term are slightly lower than in Counterfactual #1 (due to Counterfactual #5's inclusion of energy efficiency) and are higher in the long term (due to higher peaks), the 15-year levelized cost ends up being similar to Counterfactual #1.

Counterfactual #3 displays prices that are different from Counterfactual #5, despite their similarity in terms of load components. This counterfactual does not include any energy efficiency measures but does include building electrification measures. As a result, it has the highest seasonal peaks of any modeled scenario. Because of these high peaks, the model builds quantities of gas capacity that exceed those built in any other scenario. Because each single gas capacity addition is large, these additions lead to larger reserve margins (i.e., larger than they would be if the "perfect" amount of capacity could have been added), which leads to lower capacity prices. Furthermore, beginning in the late 2030s, Counterfactual #3 has system stress periods that occur outside of peak load times. While this phenomenon is present to some extent in the other winter peaking scenarios, the lack of energy efficiency measures intensifies the issue in this counterfactual. Therefore, in some years, energy requirements drive gas additions, as opposed to capacity requirements. As a result, Counterfactual #3 contains capacity additions beyond the bare minimum required by capacity market economics, leading to lower capacity prices. Importantly, these decisions are made with the model looking at the entire modeling time horizon (sine the model has "perfect foresight"), which means that some decisions may look uneconomic in the near-term but are in fact economic when considering the entire study period.

Counterfactual #4 has the same load components as Counterfactual #5, without the BTM storage resources and demand response resources. Absent this exogenous firm capacity, the near-term reserve margin is slightly lower, which causes higher near-term summer capacity prices. Counterfactual #4 builds one additional gas combined cycle plant in 2035 than Counterfactual #5. This extra combined cycle plant has a slightly greater capacity than the exogenous firm capacity and demand response

[198] At the time of this writing, there are few other published studies against which to benchmark our results. One such example is a December 2023 study published by Analysis Group, focused on projecting capacity costs in FCA 18 alone (see Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets Discussion of Draft Results. Analysis Group. December 13, 2023. Available at https://www.iso-ne.com/static-assets/documents/100006/a03b_mc_2023_12_12_14_alternative_fcm_commitment_horizons_agi_presentation.pdf.) We note that this study (slides 54 and 57) indicates results that are broadly in line with our own findings, with the higher clearing prices indicated by this study perhaps caused by that study's higher peak demand assumptions, compared to AESC 2024's Counterfactual #1.

Schedule MM-R1

resources in Counterfactual #5. Therefore, Counterfactual #4 has a slightly higher reserve margin and lower capacity prices in 2035. In the latter section of the study period, Counterfactual #4 continues to build a mix of batteries, peaker power plants and combined cycle power plants in place of the exogenous firm capacity present in Counterfactual #5. Similar to Counterfactual #3, the "lumpy" nature of these capacity additions leads to larger reserve margins and correspondingly lower capacity prices.

In Counterfactual #6, in comparison with Counterfactual #5, the absence of the non-programmatic BTM storage prevents the retirement of 227 MW of steam turbines in 2028 and shifts the addition of the first new gas combined cycle plant forward from 2035 to 2028. This results in a similar market effect to Counterfactual #4. In the near-term, the absence of exogenous firm capacity leads to higher capacity prices, though not yet high enough to justify new capacity additions, from a total system cost optimization perspective. By 2033, capacity prices are high enough to drive new power plant additions, leading to a jump up in the reserve margin.

The following section delves deeper into the drivers that cause some of the capacity price outputs observed in the modeled counterfactuals. In the next section, Table 64 displays the seasonal capacity prices for all scenarios in tabular form under the new capacity market structure (which begins in FCA 19, or 2028), while Figure 41 compares these capacity prices with each scenario's peak demand forecast and estimated reserve margin.

In one year, in one counterfactual (out of the 138 years capacity prices are estimated across all six counterfactuals), the capacity price clears at a level that is below EnCompass' lowest threshold for estimating capacity prices. In this single year, we use the slope of the supply curve from the most recently completed auction to estimate capacity prices.

Understanding capacity market dynamics

The capacity market has several related inputs that interact and contribute to fluctuations in the clearing price from year to year. Here, we outline the general principles that impact capacity market dynamics and discuss how those principles play out in a few different modeled years.

Fundamentally, seasonal capacity market prices are reflective of the system's seasonal reserve margin. In AESC 2024, we define the seasonal reserve margin to be the ratio of MW of firm capacity (as opposed to nameplate capacity) to the MW demand in the peak hour of that season. We conducted a stochastic analysis to calculate technology specific capacity accreditations, or effective load carrying capacities (ELCCs), which we then used to calculate firm capacities (see "Avoided capacity methodology for June 2028 and later" section above). This process uses marginal ELCCs, which represent the incremental reliability that one additional megawatt (MW) of nameplate capacity would provide. Marginal ELCCs indicate the capacity contribution that one unit addition of a specific technology would provide during times of system stress. They are calculated by comparing the reduction in unserved energy due to one incremental MW of a given technology to the reduction in unserved energy that one MW of perfect capacity would result in. Critically, system stress times may not necessarily be correlated with peak load hours, especially as intermittent resource penetration increases. When this is the case, resources may outperform their accredited capacities during the season's peak load hours. As a result, reserve margins calculated using firm capacities can be significantly lower than reserve margins calculated using nameplate capacities. In some cases, reserve margins may be near zero or even negative if the load during system stress times is lower than peak load.

When the system has a lower reserve margin, the grid is tight on firm capacity, so the market clears at a higher price. When the system has a higher reserve margin, the grid has excess firm capacity, so the market clears at a lower price.

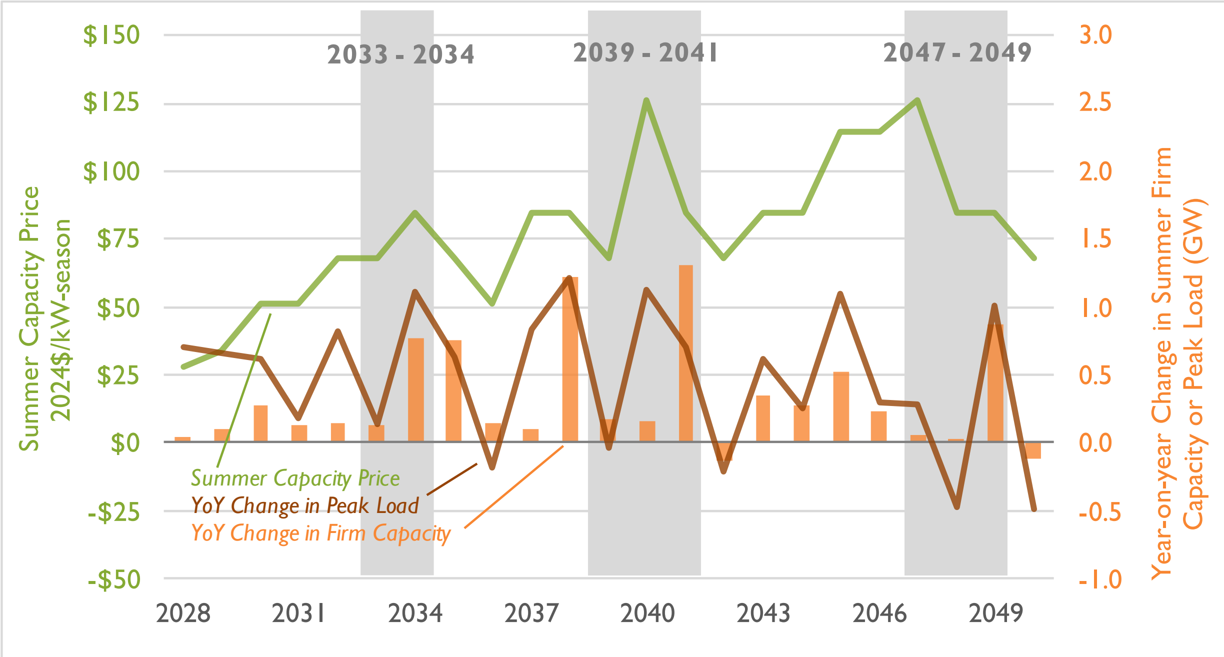
To understand the fluctuations in the capacity market price on an annual basis, it is important to consider changes to the reserve margin that have occurred relative to the previous year. Changes in the reserve margins are driven by (1) changes in peak load and (2) changes in firm capacity. In general, if the peak load increases by a greater amount than the firm capacity increases, the reserve margin will decrease, resulting in a higher capacity market clearing price relative to the previous year. If the firm capacity increases by a greater amount than the peak load, the reserve margin will increase, and the capacity market will clear at a lower price.

In modeling, as in reality, there are several factors that can lead to unpredictable capacity market results. We used full optimization settings in the capacity expansion step of our modeling, meaning the model is able to “see” the entire study time period when it is making decisions regarding resource builds. While results for a single year may sometimes appear uneconomic when considered in isolation, systemwide results considered over the entire study period will always be economic. This is reflective of actual planning processes, where entities will consider future market projections when making major investment decisions, as opposed to just thinking one year at a time. Another factor is the “lumpiness” of resource builds and retirements. Fossil power plants tend to be relatively large relative to the size of the New England market, and the addition or retirement of a few large power plants can materially impact the reserve margin. This inherent lumpiness of resource builds, combined with the ability of the model to consider future system needs, means that the model may sometimes add capacity earlier than necessary, if it will be needed in the future.

By examining a few demonstrative modeled years, we can understand how the principles described above apply in practice. Figure 39 illustrates how key variables change over time in Counterfactual #1. Since Counterfactual #1 is a summer peaking system throughout the study period, we focus on analyzing summer results for this counterfactual. Counterfactual #5 results are discussed afterwards to illustrate how these principles apply in a market that undergoes a transition to winter peaking.

Schedule MM-R1

Figure 39. Trends in summer capacity prices and year-on-year changes in summer firm capacity and summer peak load for Counterfactual #1.



Notes: Year-on-year change in firm capacity includes all endogenous and exogenous resource additions and retirements.

Consider the following time periods in Figure 39 above (highlighted in grey):

- **2033 to 2034:** Capacity prices increase from 2033 to 2034. During this time period, we observe peak loads increasing by a greater magnitude than the increase in firm capacity. As a result, the reserve margin in 2034 is lower than the reserve margin in 2033, causing the market to clear at a higher price.
- **2039 to 2041:**
  - *2039 to 2040:* Capacity prices increase significantly from 2039 to 2040. Between these two years, we observe a substantial increase in peak load, but a very small increase in firm capacity. This causes the reserve margin to decrease, leading to high prices. However, despite the capacity market clearing at a high price, the price is not yet high enough to drive new builds in 2040. This is because the reserve margin in the 2036-2039 era was relatively high, which led to some buffer for the reserve margin. In other words, there was room for the reserve margin to decrease after 2039 without the need for new builds.
  - *2040 to 2041:* From 2040 to 2041, there is a moderate increase in peak load. Since the reserve margin in 2040 was already low, this increase in peak loads consumes the remaining buffer. As a result, there is a substantial buildout of net firm capacity in 2041, which increases the reserve margin, driving prices down.
- **2047 to 2049**:
  - *2043 to 2047:* In 2047, capacity prices reach a local peak. The substantial buildout of capacity that occurred in 2041 increases the reserve margin at the start of the 2040s,

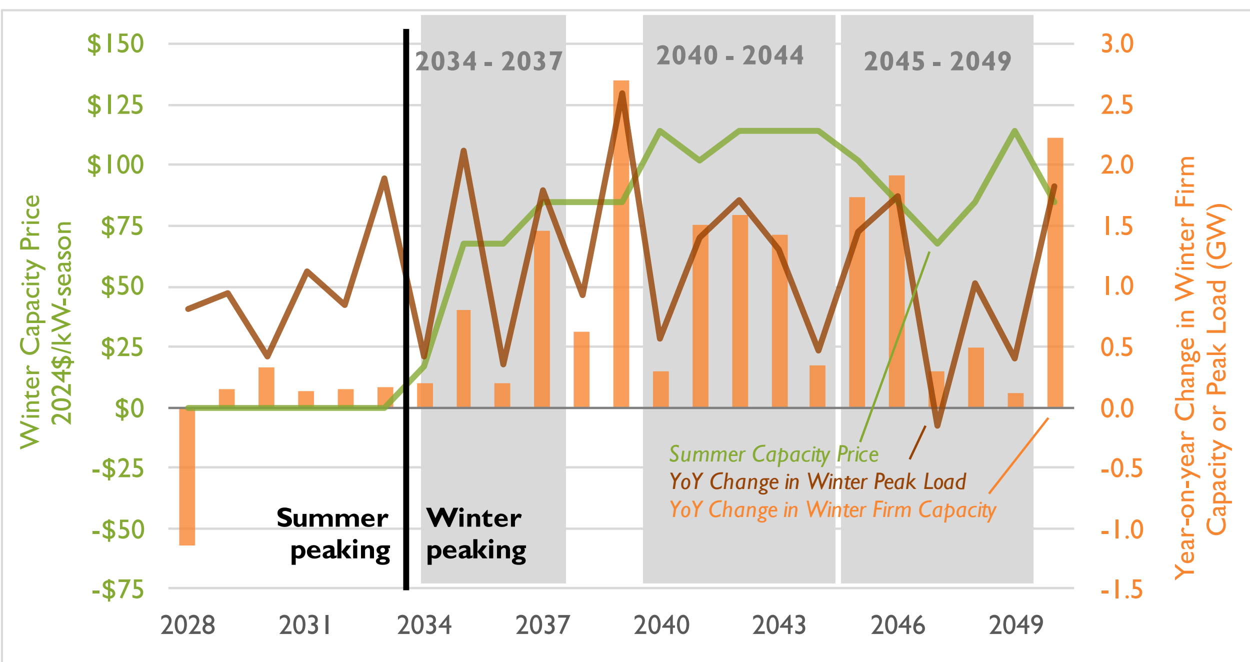
Schedule MM-R1

but this room is reduced over the course of the 2040s as firm additions are made at a slower rate than peak demand growth occurs. This leads to a gradual decay in the reserve margin from 2043 through 2047 and gradually higher capacity prices.

- *2047 to 2048:* Capacity prices decrease significantly from 2047 to 2048, without significant net firm capacity additions. This is because this time period is one of the few instances where peak load decreases year-on-year in Counterfactual #1. At the same time, the quantity of firm capacity does not significantly change year-on-year. This leads to a higher reserve margin, which produces a lower capacity price.
- *2048 to 2049:* While there is a significant increase in load in 2049, this is almost exactly matched by an increase in firm capacity. This results in capacity market prices staying constant from 2048 to 2049.

For a second example, consider Figure 40, which depicts changes in winter capacity prices, peak loads, and firm capacity for Counterfactual #5. Unlike Counterfactual #1, Counterfactual #5 transitions to a winter peaking system starting in 2034. In general, over the entire study period, prices in Counterfactual #5 tend to be higher and more stable than prices in Counterfactual #1. While year-on-year changes in winter peak demand fluctuate, they mostly fluctuate considerably above zero. Firm capacity additions are usually right below, or right around, the year-on-year changes in peak demand. Reserve margins are tighter, since just enough capacity is being added to maintain reliability.

Figure 40. Trends in winter capacity prices and year-on-year changes in winter firm capacity and winter peak load for Counterfactual #5



Notes: Year-on-year change in firm capacity includes all endogenous and exogenous resource additions and retirements.

Consider the following time periods in Figure 40 above (highlighted in grey):

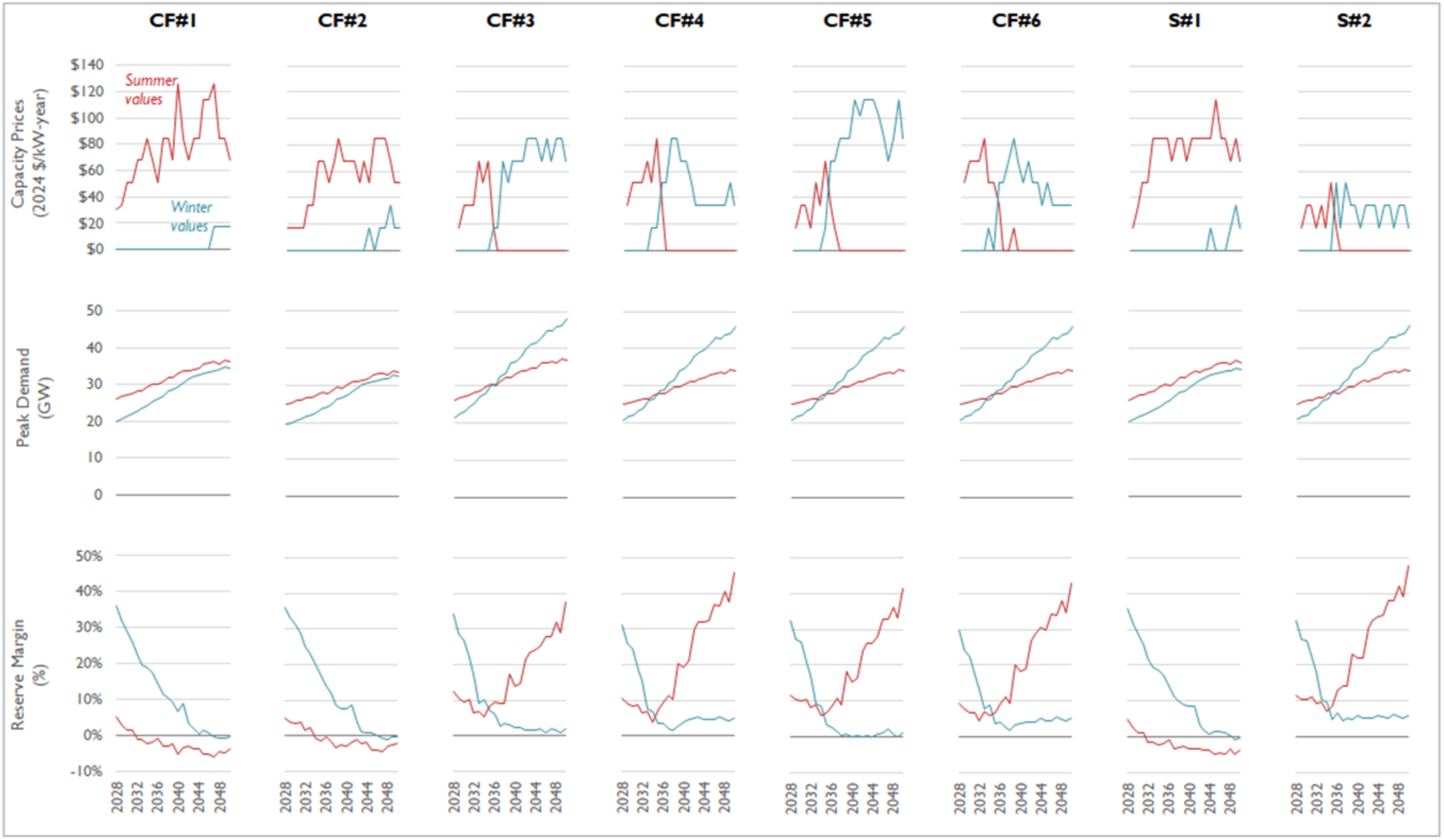
- **2034 to 2037:**

Schedule MM-R1

- *Pre-2034:* From 2028 through 2033, the system is summer peaking, and the winter capacity market clears beyond the winter maximum reserve margin, at zero dollars. As the winter peak increases, winter reserve margins decrease, eventually producing a low winter capacity market price in 2034.
- *2034 to 2037:* From 2034 through 2036, the summer and winter peak are close together, so there are nonzero capacity prices in both seasons. However, as building electrification load continues to increase, the winter peak increases past the summer peak. In 2037, firm capacities built to serve winter energy are so large relative to the summer peak that the summer capacity price falls to zero. During this period, the winter peak increases are consistently greater than the firm capacity additions, so capacity prices rise steadily.

- **2040 to 2044:** Prices are high and relatively stable from 2040 through 2044. In 2040, we see a slight price increase where growth in demand outpaces growth in firm capacity, but this is followed by a slight decrease when the converse occurs in 2041. In general, cumulative capacity additions are similar in magnitude to the cumulative changes in firm capacity that occur during this period. Reserve margins stay around the same level, so capacity prices follow suit.
- **2045 to 2049:**
  - *2045 to 2047:* Three consecutive years of greater increases in winter firm capacity relative to year-on-year changes in winter peak loads drive the reserve margin up. This causes capacity prices to fall.
  - *2048 to 2049:* Capacity prices rise back up to their previous high level during this period as comparatively less firm capacity is added. Prices peak in advance of a significant capacity addition in 2050.

Figure 41. Comparisons of capacity prices, peak demand, and reserve margins across all modeled scenarios during the new capacity market structure period (post-FCA 18)



Schedule MM-R1

Table 64. Seasonal capacity prices for all modeled scenarios during the new capacity market structure period (post-FCA 18) (2024 $/kW-year)

Year	FCA #	Summer								Winter							
		CF#1	*CF#2*	*CF#3*	*CF#4*	*CF#5*	*CF#6*	*S#1*	*S#2*	*CF#1*	*CF#2*	*CF#3*	*CF#4*	*CF#5*	*CF#6*	*S#1*	*S#2*
2028	19	$31	$17	$17	$34	$17	$51	$17	$17	$0	$0	$0	$0	$0	$0	$0	$0
2029	20	$34	$17	$34	$51	$34	$68	$34	$34	$0	$0	$0	$0	$0	$0	$0	$0
2030	21	$51	$17	$34	$51	$34	$68	$51	$34	$0	$0	$0	$0	$0	$0	$0	$0
2031	22	$51	$17	$34	$51	$17	$68	$51	$17	$0	$0	$0	$0	$0	$0	$0	$0
2032	23	$68	$34	$68	$68	$51	$85	$85	$34	$0	$0	$0	$0	$0	$0	$0	$0
2033	24	$68	$34	$51	$51	$34	$51	$85	$17	$0	$0	$0	$17	$0	$17	$0	$0
2034	25	$85	$68	$68	$85	$68	$51	$85	$51	$0	$0	$0	$17	$17	$0	$0	$0
2035	26	$68	$68	$17	$34	$34	$34	$85	$17	$0	$0	$17	$51	$68	$51	$0	$51
2036	27	$51	$51	$0	$0	$17	$0	$68	$0	$0	$0	$17	$51	$68	$51	$0	$17
2037	28	$85	$68	$0	$0	$0	$0	$85	$0	$0	$0	$68	$85	$85	$68	$0	$51
2038	29	$85	$85	$0	$0	$0	$17	$85	$0	$0	$0	$51	$85	$85	$85	$0	$34
2039	30	$68	$68	$0	$0	$0	$0	$68	$0	$0	$0	$68	$68	$85	$68	$0	$34
2040	31	$126	$68	$0	$0	$0	$0	$85	$0	$0	$0	$68	$68	$114	$51	$0	$17
2041	32	$85	$68	$0	$0	$0	$0	$85	$0	$0	$0	$68	$51	$102	$68	$0	$34
2042	33	$68	$51	$0	$0	$0	$0	$85	$0	$0	$0	$85	$34	$114	$51	$0	$34
2043	34	$85	$68	$0	$0	$0	$0	$85	$0	$0	$0	$85	$34	$114	$51	$0	$34
2044	35	$85	$51	$0	$0	$0	$0	$85	$0	$0	$17	$85	$34	$114	$34	$17	$17
2045	36	$114	$85	$0	$0	$0	$0	$114	$0	$0	$0	$68	$34	$102	$51	$0	$34
2046	37	$114	$85	$0	$0	$0	$0	$85	$0	$0	$17	$85	$34	$85	$34	$0	$34
2047	38	$126	$85	$0	$0	$0	$0	$85	$0	$17	$17	$68	$34	$68	$34	$0	$17
2048	39	$85	$68	$0	$0	$0	$0	$68	$0	$17	$34	$85	$34	$85	$34	$17	$34
2049	40	$85	$51	$0	$0	$0	$0	$85	$0	$17	$17	$85	$51	$114	$34	$34	$34
2050	41	$68	$51	$0	$0	$0	$0	$68	$0	$17	$17	$68	$34	$85	$34	$17	$17

Schedule MM-R1

5.2. Uncleared capacity calculations

Any load reduction that clears provides avoided capacity costs in the year in which the resource participates in the capacity auction. For example, if a program administrator has bid 1 MW into FCA 17 and expects to deliver that 1 MW starting in the summer of 2026 (the beginning of the FCA 17 commitment period) that benefit will receive the full avoided capacity cost benefit starting in 2026. 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.[199]

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. Other measures, such as building electrification measures, affect the demand constraint, rather than supply constraint and cannot be bid. Thus, a program administrator may bid some (or only a portion) of the anticipated capacity into the FCA.[200]

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, 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 multiple 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.[201] 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 five years after their installation date. Table 66 describes a hypothetical timeline where a measure is installed in 2024 but does not produce an impact on the capacity market for another five years.

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[199] Expired measures are not bid into the market and do not receive a capacity price. In AESC 2024, these expired measures are assumed to be replaced with measures of an equivalent level of efficiency and are accounted for in the conventional load forecast. This results in them being taken into account of the demand side of the capacity market calculation in future years.

[200] 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) and 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 2013 to 2016, the first ARA averaged about 54 percent of the FCA price, the second ARA averaged 38 percent, and the third ARA averaged 39 percent.

[201] 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.

Schedule MM-R1

Table 65. Illustration of when uncleared capacity begins to have an effect

Year	Event
2024	Measure is installed and begins to reduce load.
2025	ISO New England publishes a load forecast that is partially impacted by the load reductions installed in the previous year.
2026	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.
2027	-
2028	-
2029	The year the prices from the capacity auction take place. The uncleared measure now begins to have an impact.

Meanwhile, Table 66 describes a hypothetical timeline where a measure is installed in 2028, the first year of the new market structure. This timeline has been shortened from five years because we assume ISO New England adopts a prompt auction structure. In a prompt market, the phase-in timeline is accelerated by three years relative to a three-year forward market. In the example shown in Table 66, the auction held in 2030 would procure capacity for the year beginning in June 2030, and thus the phase-in would begin just two years after the installation of the measure.

Table 66. Illustration of when uncleared capacity begins to have an effect

Year	Event
2028	Measure is installed and begins to reduce load.
2029	ISO New England publishes a load forecast that is partially impacted by the load reductions installed in the previous year.
2030	Early 2030: An annual capacity auction occurs. The demand curve in this auction is based on the load forecast made in the previous year. June 2030: The year the prices from the capacity auction take place. The uncleared measure now begins to have an impact.

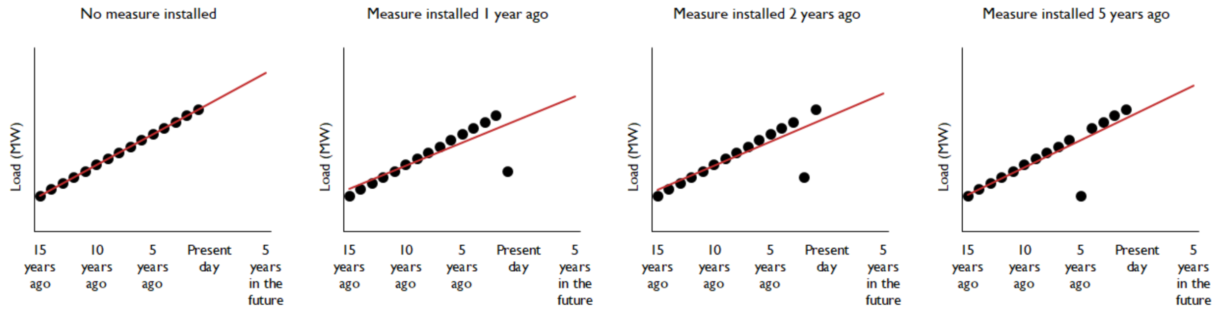
Phase-out

However, once impacts begin, 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 42 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 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.

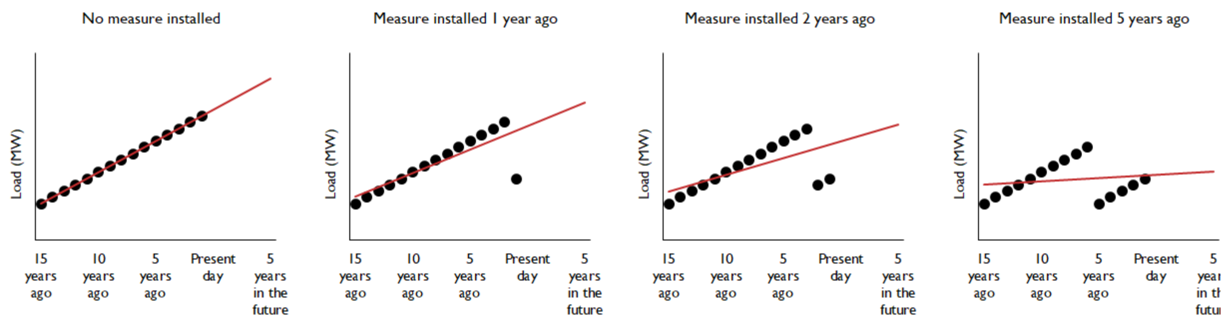
Schedule MM-R1

Figure 42. Illustrative impacts of a single-year load reduction on the peak forecast



In a second example, Figure 43 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 43. Illustrative impacts of a five-year load reduction on the peak forecast



Load forecast effect 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 68). 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. These simplified blocks are the same ones used in previous AESC studies, which were developed via consensus through discussions with the Study Group.

Table 67. Load forecast effect schedule for a measure with a one-year lifetime installed in 2024

	Percent of uncleared capacity impact in place
2024	0%
2025	0%
2026	0%
2027	0%
2028	0%
2029	30%
2030	20%
2031	20%
2032	20%
2033	10%
2034	0%
2035	0%
2036	0%
2037	0%
2038	0%

Just as the phase-in described above is assumed to be shifted three years earlier under the new market structure, we assume that the load forecast effect (LFE) schedule is also shifted forward three years (see Table 68).

Table 68. Load forecast effect schedule for a measure with a one-year lifetime installed in 2028

	Percent of uncleared capacity impact in place
2028	0%
2029	0%
2030	30%
2031	20%
2032	20%
2033	20%
2034	10%
2035 and later years	0%

However, because we assume these effects are 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. In general, we assume the same kind of LFE effect in AESC 2024 as we did in AESC 2021. However, the structure is more complex due to the switch in capacity market structures.

First, Table 69 shows the schedule assumed for measures with lifetimes varying from one to ten years, under a future in which there is no new capacity market.[202] 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

[202] See the *AESC 2024 User Interface* for a detailed schedule of uncleared capacity DRIPE effects for measures lasting one through 35 years.

Schedule MM-R1

the actual load reduction integrated into the forecast is the sum of the effect from each program year.[203] For example, in 2030, the assumed effect is equal to 50 percent, or the sum of the 2029 impact from a one-year program and the 2030 impact from a one-year program.

Table 69. Load forecast effect schedule for uncleared capacity value for measures with L lifetimes installed in 2024, assuming no new market structure

	L=1	L=2	L=3	L=4	L=5	L=6	L=7	L=8	L=9	L=10
2024	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2026	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2027	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2028	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2029	30%	30%	30%	30%	30%	30%	30%	30%	30%	30%
2030	20%	50%	50%	50%	50%	50%	50%	50%	50%	50%
2031	20%	40%	70%	70%	70%	70%	70%	70%	70%	70%
2032	20%	40%	60%	90%	90%	90%	90%	90%	90%	90%
2033	10%	30%	50%	70%	100%	100%	100%	100%	100%	100%
2034	0%	10%	30%	50%	70%	100%	100%	100%	100%	100%
2035	0%	0%	10%	30%	50%	70%	100%	100%	100%	100%
2036	0%	0%	0%	10%	30%	50%	70%	100%	100%	100%
2037	0%	0%	0%	0%	10%	30%	50%	70%	100%	100%
2038	0%	0%	0%	0%	0%	10%	30%	50%	70%	100%

Note: Measures installed in subsequent years use the same schedule, but shifted by an appropriate number of years (e.g., a measure installed in year 2025 would see effects beginning in year 2030). Note that effects for measures with measure lives of six years or greater continue to phase out after 2038. Because of this, the AESC 2024 User Interface calculates these effects through 2060 for each individual year, rather than extrapolating values.

However, we are assuming a switch to a new capacity market in 2028. This market utilizes a prompt structure, which for the purposes of the LFE schedule, means that effects are shifted three years early (see Table 70). This means that some market effects are actually shifted before the 2028 market changeover. As a result, these market benefits are "lost" and cannot be counted by any measure. In other words, a shift from a three-year-ahead market to a prompt market means that three years of load regressions, and their associated benefits become lost. Measures installed in 2028 and following years would realize the full time series of market benefits.

[203] 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.

Schedule MM-R1

Table 70. Load forecast effect schedule for uncleared capacity value for measures with L lifetimes installed in 2024, assuming a new market structure active in 2028

	L=1	L=2	L=3	L=4	L=5	L=6	L=7	L=8	L=9	L=10
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%
2036	0%	0%	0%	0%	0%	0%	10%	30%	50%	70%
2037	0%	0%	0%	0%	0%	0%	0%	10%	30%	50%
2038	0%	0%	0%	0%	0%	0%	0%	00%	10%	30%

Note: Measures installed in subsequent years use the same schedule, but shifted by an appropriate number of years (e.g., a measure installed in year 2025 would see effects beginning in year 2030). Note that effects for measures with measure lives of six years or greater continue to phase out after 2038. Because of this, the AESC 2024 User Interface calculates these effects through 2060 for each individual year, rather than extrapolating values.

Reserve margin requirements

Each year ISO New England calculates a 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 13 percent (see Table 71). We update our reserve margin assumptions throughout the study period to be consistent with the reserve margins calculated in the Monte Carlo analysis as described in Section 5.1: *Wholesale electric capacity market inputs and cleared capacity calculations*. AESC 2024 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 can be much higher when incumbent generation owners are willing to accept low capacity payments. Under the new market structure beginning in 2028, reserve margins are likely to be lower than under the old market structure, and can, in certain circumstances, even be negative. This is reflective of the fact that the ISO's RCA methodology accounts for all the limitations of each resource in its accreditation values, resulting generally in fewer accredited MW per resource but more reliability value per accredited MW. As a result, a smaller amount of total accredited capacity is needed to achieve the same reliability objective. In addition, the capacity market under RCA will procure resources to meet system needs during high-risk hours. While the capacity market has historically procured capacity entirely for peak load conditions, high-risk conditions on the future grid could include some more moderate load hours when certain generation resources (such as renewables, or gas plants in the winter) are less available. If more moderate load hours drive the need for capacity, the total MW of capacity needed is smaller relative to peak loads.

Schedule MM-R1

Table 71. Calculated reserve margins for years before the switch to a prompt market

Summer	FCA #	Calculated reserve margin
2023	14	13%
2024	15	14%
2025	16	13%
2026	17	11%
Average (used in 2027)	**-**	**13%**

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 63)
- The effect schedule that matches the measure's lifetime (e.g., the values in Table 69)
- One plus the reserve margin (e.g., the values in Table 71)

Table 72 describes the uncleared capacity benefit in Counterfactual #1. This table describes benefits for measures installed in 2024, with measure lives ranging from one to ten years. Values shown in this table are the sum of benefits that accrue both from the current capacity market structure, as well as the future seasonal capacity market structure.

Schedule MM-R1

Table 72. Uncleared capacity value for measures with L lifetimes installed in 2024 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
2024	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2025	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2028	$6	$13	$23	$23	$23	$23	$23	$23	$23	$23
2029	$7	$14	$21	$31	$31	$31	$31	$31	$31	$31
2030	$5	$16	$26	$36	$52	$52	$52	$52	$52	$52
2031	$0	$5	$15	$26	$36	$52	$52	$52	$52	$52
2032	$0	$0	$7	$20	$34	$47	$67	$67	$67	$67
2033	$0	$0	$0	$7	$20	$34	$47	$67	$67	$67
2034	$0	$0	$0	$0	$8	$25	$42	$58	$83	$83
2035	$0	$0	$0	$0	$0	$7	$20	$33	$47	$67
2036	$0	$0	$0	$0	$0	$0	$5	$15	$25	$35
2037	$0	$0	$0	$0	$0	$0	$0	$8	$25	$41
2038	$0	$0	$0	$0	$0	$0	$0	$0	$8	$25
15-Year Levelized	$1	$3	$6	$10	$14	$18	$22	$27	$31	$35

Note: Effects for measures with measure lives of six years or greater continue to phase out after 2038. Because of this, the AESC 2024 User Interface (tab "Appdx J") calculates these effects through 2060 for each individual year, rather than extrapolating values. See the AESC 2024 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 2024 would be equal to the sum of the values from 2024 through 2060, regardless of whether that measure had a 1-year measure life or a 30-year measure life.[204] See *Appendix J: Guide to Calculating Avoided Costs for Cleared and Uncleared measures* for more information.

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 72 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.

[204] This is the same approach used for summing avoided costs for uncleared capacity and uncleared capacity DRIPE, but no other avoided cost categories.

Schedule MM-R1

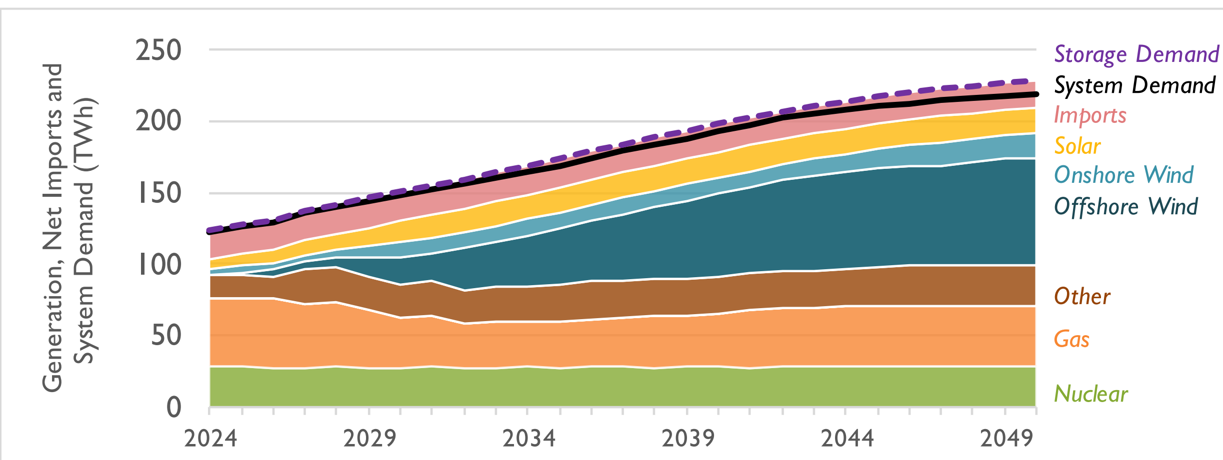
6. AVOIDED ENERGY COSTS

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 2024 and AESC 2021.[205] On a levelized basis, the 15-year AESC 2024 annual all-hours price for Counterfactual #1 is $50 per MWh, compared to the equivalent value of $46 per MWh from AESC 2021. This represents a price increase of 9 percent. Relative to Counterfactual #1, counterfactuals and years with higher loads and peaks tend to have higher energy prices, while counterfactuals with lower loads and peaks tend to have lower energy prices. The increase in energy prices observed in AESC 2024 is primarily due to higher near-term wholesale gas prices and a deferral of zero-marginal-cost clean energy to later in the study period, relative to AESC 2021.

6.1. Forecast of energy and energy prices

Figure 44 presents the projected level of New England electric system energy from 2024 to 2050. The EnCompass model estimates these energy levels given the capacities specified in Figure 45, fuel prices, availability factors, heat rates, and other unit attributes. Figure 44 assumes a future in which no new energy efficiency is added in 2024 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.

Figure 44. New England-wide generation, imports, and system demand in Counterfactual #1

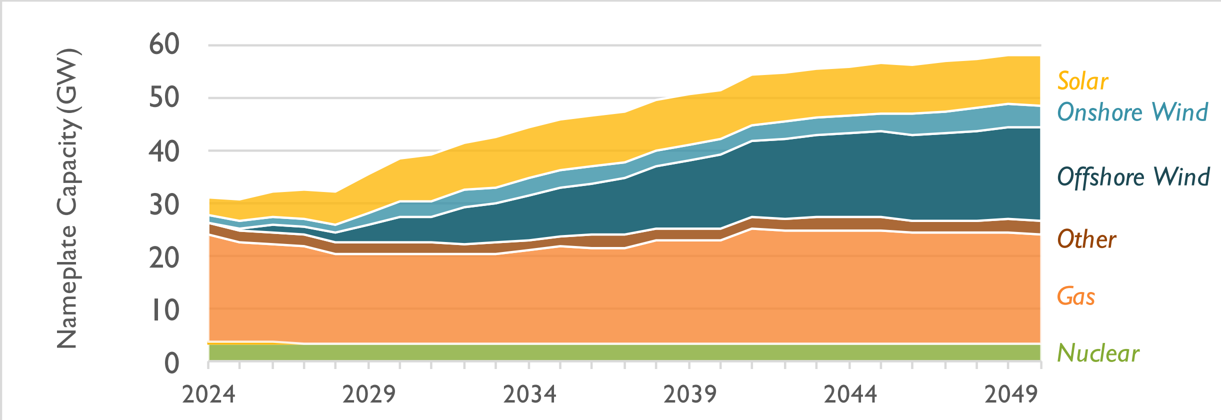


Notes: "Other Fossil" contains generation from steam turbines (including coal), combustion turbines, fuel cells, and other miscellaneous fossil-fuel-fired power plants. "Other" contains generation from energy storage, demand response, municipal solid waste, landfill gas, and other miscellaneous fuel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

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

Schedule MM-R1

Figure 45. 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

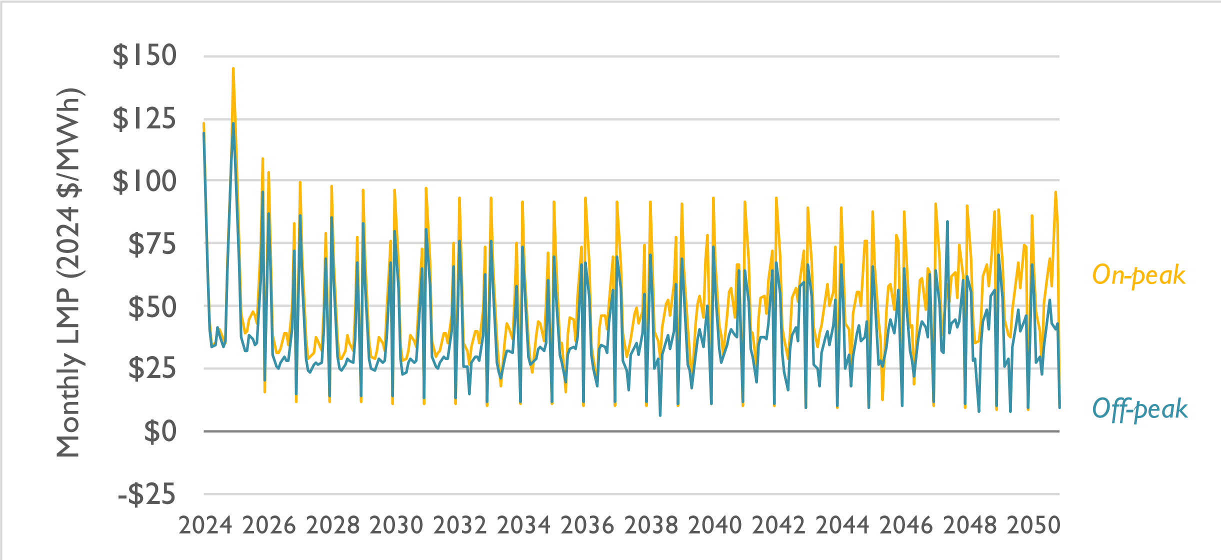
In addition to modeling the generation shown in Figure 45, the EnCompass model also produces wholesale energy prices (see Figure 46 and Table 73).[206] These modeled prices change over time (and on a peak and off-peak basis) depending on the system demand, available units, transmission constraints, fuel prices, and other attributes. Over time, energy prices generally track the trend in gas prices. However, this relationship appears to be weaker in AESC 2024 than in previous analyses, in part due to the larger quantity of offshore wind and other zero-marginal cost generators that suppress prices, especially in off-peak hours. Energy prices demonstrate increased variability towards the latter half of the study period due to an increased number of hours with demand response, storage, and clean energy being on the margin.

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, 310 CMR 7.74, and proposed rules under Section 111 of the *Clean Air Act*.

[206] Note that all summarized energy prices are calculated using a load-weighted average.

Schedule MM-R1

Figure 46. Wholesale energy price projection for WCMA in Counterfactual #1



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

Schedule MM-R1

Table 73. AESC 2024 wholesale energy price projection in Massachusetts in Counterfactual #1 (2024 $ per MWh)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
2024	$62.82	$78.55	$75.49	$38.14	$37.47
2025	$63.77	$79.24	$75.82	$40.02	$38.89
2026	$50.51	$62.48	$60.15	$31.97	$30.73
2027	$48.47	$60.20	$57.88	$30.09	$29.23
2028	$48.36	$59.49	$57.62	$30.31	$30.01
2029	$47.77	$58.71	$56.56	$30.38	$29.83
2030	$47.10	$57.65	$54.84	$31.09	$30.17
2031	$48.29	$58.62	$56.14	$32.38	$31.31
2032	$46.64	$56.93	$51.89	$33.11	$31.69
2033	$47.59	$56.80	$52.59	$34.90	$34.13
2034	$47.68	$55.81	$52.77	$35.93	$34.98
2035	$48.00	$56.23	$52.43	$36.99	$35.43
2036	$47.57	$55.34	$50.60	$38.70	$36.15
2037	$48.17	$57.13	$50.10	$39.54	$36.08
2038	$48.98	$59.18	$47.40	$42.92	$38.16
2039	$46.67	$56.78	$43.09	$42.37	$37.94
2040	$48.54	$55.22	$48.35	$44.88	$39.57
2041	$47.09	$54.62	$45.57	$44.39	$37.86
2042	$48.13	$56.15	$45.78	$45.27	$39.57
2043	$47.56	$55.96	$44.06	$45.63	$39.34
2044	$48.68	$59.83	$42.29	$46.54	$40.72
2045	$50.34	$58.31	$46.99	$48.32	$42.97
2046	$50.44	$56.35	$48.26	$49.33	$44.00
2047	$55.84	$61.82	$56.68	$52.55	$45.77
2048	$52.15	$59.85	$46.72	$52.44	$46.71
2049	$57.41	$59.96	$61.55	$55.16	$46.72
2050	$54.42	$63.40	$45.31	$58.43	$49.60

Comparison to AESC 2021

Table 74 shows a comparison between AESC 2021 and AESC 2024 for the 15-year levelized costs for Massachusetts. Prices are shown for all hours, and for the four periods analyzed in previous AESC studies. Generally speaking, annual average prices in the AESC 2024 counterfactuals are similar to the annual energy price in AESC 2021's Counterfactual #1. Higher near-term prices (especially in peak hours) in AESC 2024 tend to be offset by lower mid- and longer-term prices, producing 15-year levelized costs similar to those observed in AESC 2021. These energy price trends generally track the assumptions related to natural gas price inputs. In AESC 2024, counterfactuals with lower loads and peaks tend to have lower energy prices on a 15-year levelized basis. We note that counterfactuals with more fossil retirement and fewer fossil additions (such as Counterfactual #2) tend to have more volatile energy prices in the very long term (e.g., after 2040) as a result of more wind, solar, battery storage, and demand response resources being on the margin.

Schedule MM-R1

Table 74. Comparison of energy prices for Massachusetts (2024 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2021 Counterfactual 1	$46.11	$52.90	$51.02	$36.88	$33.71
AESC 2024 Counterfactual 1	$50.36	$61.22	$57.34	$57.34	$33.55
AESC 2024 Counterfactual 2	$47.42	$57.41	$53.44	$53.44	$32.27
AESC 2024 Counterfactual 3	$50.92	$62.27	$58.79	$58.79	$31.53
AESC 2024 Counterfactual 4	$50.30	$61.42	$58.20	$58.20	$30.94
AESC 2024 Counterfactual 5	$50.38	$61.64	$58.06	$58.06	$31.12
AESC 2024 Counterfactual 6	$49.70	$60.75	$57.56	$57.56	$30.46
% Change: Counterfactual 1	9%	16%	12%	55%	0%
% Change: Counterfactual 2	3%	9%	5%	45%	-4%
% Change: Counterfactual 3	10%	18%	15%	59%	-6%
% Change: Counterfactual 4	9%	16%	14%	58%	-8%
% Change: Counterfactual 5	9%	17%	14%	57%	-8%
% Change: Counterfactual 6	8%	15%	13%	56%	-10%

Notes: All prices have been converted to 2024 $ per MWh. Levelization periods are 2021–2035 for AESC 2021 and 2024–2038 for AESC 2024. The real discount rate is 0.81 percent for AESC 2021 and 1.74 percent for AESC 2024. AESC 2021 values are from the AESC 2021 User Interface, while AESC 2024 values are from the AESC 2024 User Interface.

Table 75 compares 15-year levelized costs between AESC 2021 and AESC 2024 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.

Schedule MM-R1

Table 75. Avoided energy costs, AESC 2024 vs. AESC 2021 (15-year levelized costs, 2024 $ per kWh)

			Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
AESC 2024 Counterfactual 1	1	Connecticut	$0.083	$0.079	$0.079	$0.053
	2	Massachusetts	$0.090	$0.086	$0.086	$0.061
	3	Maine	$0.082	$0.078	$0.078	$0.052
	4	New Hampshire	$0.078	$0.074	$0.074	$0.048
	5	Rhode Island	$0.088	$0.084	$0.084	$0.059
	6	Vermont	$0.075	$0.070	$0.070	$0.044
AESC 2021 Counterfactual 1	1	Connecticut	$0.061	$0.060	$0.045	$0.042
	2	Massachusetts	$0.065	$0.063	$0.049	$0.046
	3	Maine	$0.060	$0.058	$0.044	$0.041
	4	New Hampshire	$0.061	$0.059	$0.045	$0.042
	5	Rhode Island	$0.068	$0.066	$0.052	$0.049
	6	Vermont	$0.057	$0.055	$0.041	$0.038
Delta	1	Connecticut	$0.022	$0.020	$0.034	$0.011
	2	Massachusetts	$0.026	$0.023	$0.037	$0.015
	3	Maine	$0.023	$0.020	$0.034	$0.011
	4	New Hampshire	$0.017	$0.015	$0.029	$0.006
	5	Rhode Island	$0.020	$0.018	$0.032	$0.009
	6	Vermont	$0.018	$0.015	$0.030	$0.006
Percent Difference	1	Connecticut	35%	33%	77%	27%
	2	Massachusetts	40%	36%	76%	32%
	3	Maine	38%	34%	77%	27%
	4	New Hampshire	28%	25%	64%	14%
	5	Rhode Island	30%	26%	60%	19%
	6	Vermont	31%	27%	73%	17%

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 2024 dollars per kWh. Levelization periods are 2021–2035 for AESC 2021 and 2024–2038 for AESC 2024. The real discount rate is 0.81 percent for AESC 2021 and 1.74 percent for AESC 2024. Values do not include losses.

6.2. Benchmarking the EnCompass energy model

The AESC 2024 Study Group requires a calibration of the dispatch model used with actual, historical data. To complete this, the Synapse Team develops modeling inputs that reflect our best understanding of electric system market operations in 2020 through 2022. This calibration is reliant on assumptions relating to available generating units, fuel prices, and system demand.

Figure 47 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 2020 through

Schedule MM-R1

2022.[207] This figure also details the percent difference between actual and modeled LMPs for each region. For example, modeled 2020 LMPs range from 6 percent lower to 3 percent higher than actual 2020 LMPs. The scale of these differences indicates that EnCompass is accurately capturing the magnitude and differential spread of LMPs across New England during 2020–2022.

Figure 47. Comparison of 2020–2022 historical and simulated 2020–2022 locational marginal prices

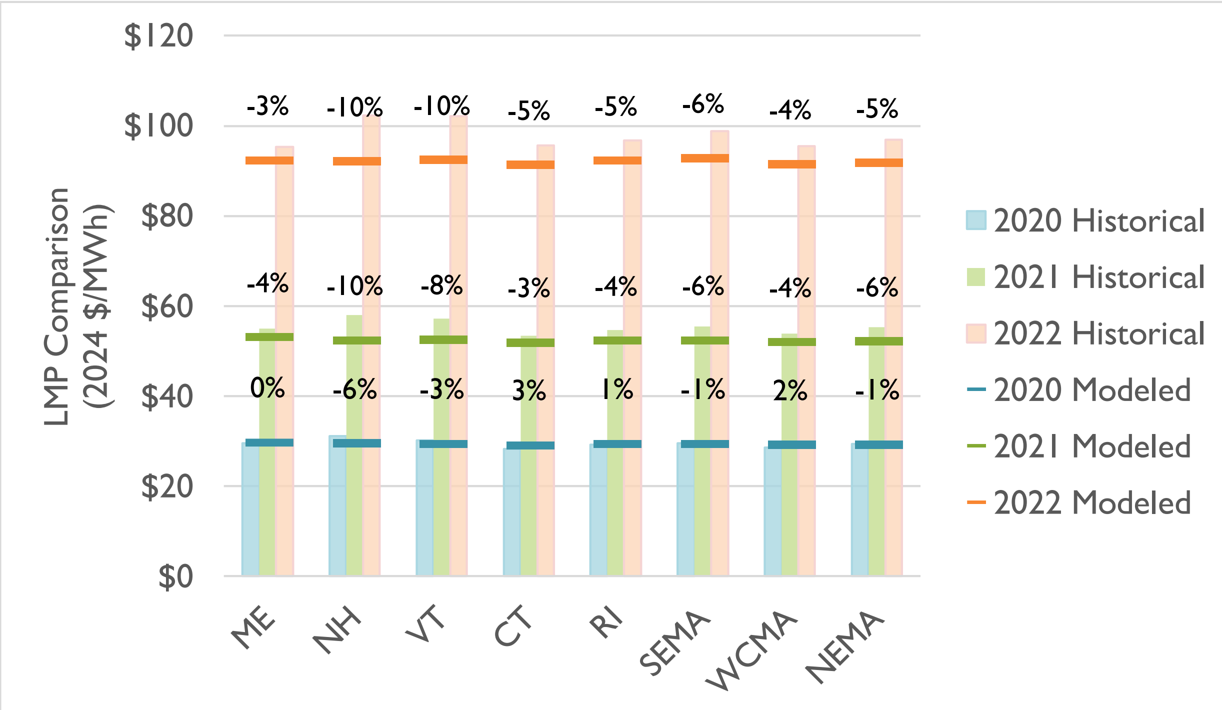


Figure 48 compares the monthly modeled LMPs for 2020–2022 in the WCMA region against actual LMPs for the same region, and Figure 49 compares daily modeled New England-wide average LMPs for 2020–2022 against historical daily average LMPs for New England. Figure 45 compares hourly modeled New England-wide average LMPs for July to December 2022 against historical hourly LMPs for New England.[208] Our calibration for 2020–2022 produces differences between modeled results and actual historical prices that that have a slightly greater spread of magnitudes than differences observed in a calibrated 2019 year from the 2021 AESC study. However, given the volatility in prices over the last few years (due in part to the COVID-19 pandemic and the conflict in Ukraine), we are now calibrating against three years of historical data instead of one year, so this slightly wider spread is expected.

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[207] 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.

[208] 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.

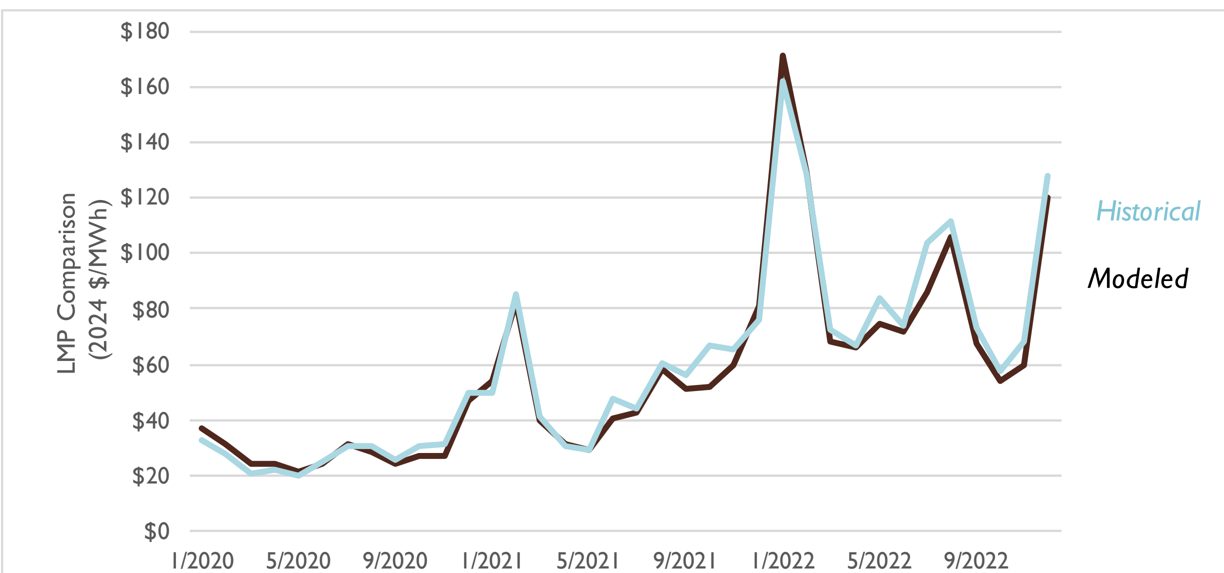
Schedule MM-R1

Our modeled generation mix matches historical generation very closely, on both an annual and monthly basis. Our calibration process incorporated daily historical gas prices, monthly liquified natural gas prices, hourly distributed solar load shapes, along with a close examination of many other variables that impact prices.

As in previous AESC studies, differences between prices on a regional or temporal basis are likely related to actual anomalies in the electric system, which are challenging to represent in an electric system dispatch model. These “anomalies” may include planned and unplanned generator and transmission outages (for which hourly data is unavailable or difficult to access) and operator discretion (which is often masked by ISO New England for confidentiality purposes). Other more granular, plant-specific factors such as fuel contracts, heat rate curves, and must-run reliability requirements are also difficult for electric system dispatch models to address.

Future modeled years are intended to be representative years and aim to include the volatility, number and intensity of extreme events observed in a typical year. The “anomalies” described above may imply that depending on variations in future years, some hourly avoided costs may be underestimated while others will be overestimated.

Figure 48. Comparison of 2020–2022 historical and simulated locational marginal prices for the WCMA region (monthly)



Schedule MM-R1

Figure 49. Comparison of 2020–2022 historical and simulated locational marginal prices for New England (daily)

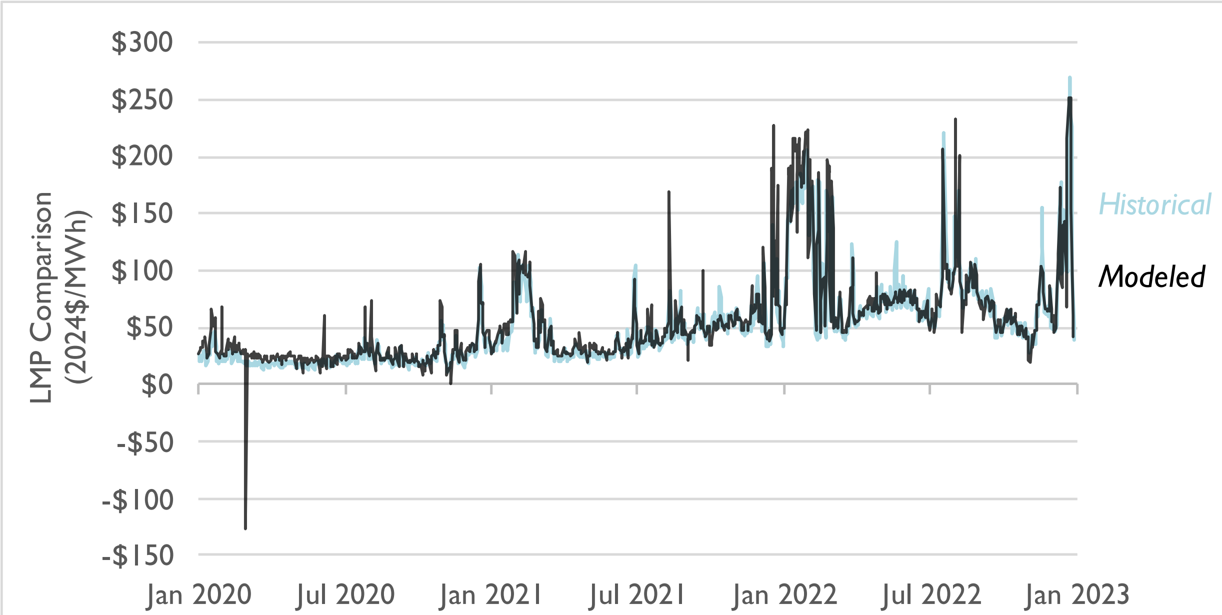
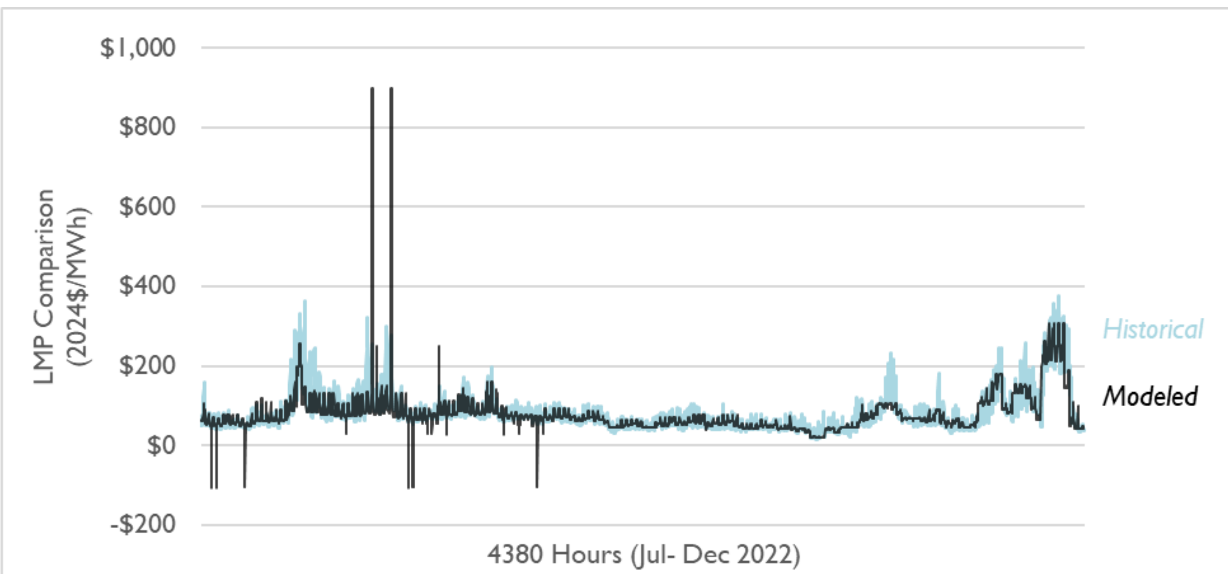


Figure 50. Comparison of July–December 2022 historical and simulated locational marginal prices for New England (hourly)



Schedule MM-R1

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. Conversely, increases in load tend to increase RPS obligations of LSEs, increasing the associated compliance costs recovered from consumers. This estimate of avoided costs includes the expected impact of avoiding each class or tier[209] of RPS[210] or Renewable Energy Standards[211] (RES) within each of the six New England states. Table 76 lists the avoided costs of compliance for Counterfactual #1.[212]

Table 76. Avoided cost of RPS compliance (2024 $ per MWh) in Counterfactual #1

	CT	ME	MA	NH	RI	VT
New Renewable / Clean Procurement Obligations	$15.36	$14.29	$13.32	$5.28	$22.62	$2.78
All Existing Procurement Obligations	$0.92	$1.33	$3.73	$3.69	$0.12	$2.75
All Other Compliance Obligations	$1.00	$0.75	$7.54	$3.00	$0.00	$2.37
Total	**$16.16**	**$16.25**	**$23.84**	**$11.92**	**$21.54**	**$7.78**

Note: A compliance obligation differs from a procurement obligation in that while it is expressed as a percent of retail sales, the certificates purchased do not represent electricity used to serve retail load.

To the extent that the price of renewable electricity (i.e., energy and RECs together) 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 for all applicable classes, by state). 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 77 compares RPS compliance costs in AESC 2024 across counterfactuals and with those estimated in AESC 2021. In general, AESC 2024 sees higher prices for meeting RPS compliance. This difference is attributable to near-term shortages and cost increases for materials and labor, delays in offshore wind deployment and regional transmission expansion, and increases in the long-term cost of entry due to the lasting effects of the war in Ukraine and the COVID-19 pandemic. The cost of RPS compliance is also impacted by increased RPS stringencies in multiple states and the addition of new RPS categories such as Maine Class I Thermal, Massachusetts Clean Peak Standard (CPS), and the Massachusetts Greenhouse

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

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

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

[212] All values are levelized over 15 years and include energy losses.

Gas Emissions Standard (GGES) for municipal light plants. On a 15-year levelized basis, costs of RPS compliance tend to be similar across counterfactuals as most counterfactuals typically feature similar renewable builds through the mid-2030s as a result of assumed renewable procurements.

Table 77. Avoided cost of RPS compliance (2024 $ per MWh)

	CT	ME	MA	NH	RI	VT
AESC 2021	$10	$9	$14	$10	$18	$5
AESC 2024 Counterfactual 1	$17	$16	$25	$12	$23	$8
AESC 2024 Counterfactual 2	$17	$16	$25	$12	$23	$8
AESC 2024 Counterfactual 3	$18	$17	$26	$12	$24	$8
AESC 2024 Counterfactual 4	$17	$16	$24	$12	$22	$8
AESC 2024 Counterfactual 5	$17	$16	$25	$12	$23	$8
AESC 2024 Counterfactual 6	$17	$16	$25	$12	$22	$8
Pcnt Change: Counterfactual 1	79%	83%	71%	21%	25%	67%
Pcnt Change: Counterfactual 2	79%	83%	71%	21%	25%	67%
Pcnt Change: Counterfactual 3	92%	91%	79%	24%	32%	70%
Pcnt Change: Counterfactual 4	77%	80%	70%	21%	22%	66%
Pcnt Change: Counterfactual 5	78%	82%	71%	21%	24%	66%
Pcnt Change: Counterfactual 6	79%	81%	74%	21%	23%	66%

Note: AESC 2021 values have been converted to 2024 dollars.

7.1. Assumptions and methodology

The purpose of this section is to describe the assumptions and methodology for forecasting the avoided cost of RPS compliance. Herein, RPS compliance refers to the fulfillment of all state-specific obligations that are expressed as a percent of load, including Massachusetts' Clean Energy Standard (CES) and Alterative Portfolio Standard (APS), Connecticut Class III (for conservation and load management), and renewable thermal requirements in Maine, New Hampshire, and Vermont.

REC (or more generally, certificate) 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 compliance on a dollar per MWh basis. Voluntary demands for Class I RECs (such as a portion of corporate renewable energy purchases and community choice aggregation) are also taken into account as a factor influencing 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, as well as a "CES-E" for existing non-emitting resources—specifically nuclear and hydroelectric facilities from Massachusetts, New Hampshire, Connecticut, and eastern Canada. Massachusetts regulations also include an Alternative Energy Portfolio Standard (APS), which applies to combined heat and power,

Schedule MM-R1

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. This same logic applies to the MA Clean Peak Standard (CPS), as well as CT Class III, Maine Class I Thermal, NH Class I Thermal, and Vermont Tier III.

Table 78 provides a summary overview of RPS and CES obligations throughout New England. Maine Class I Thermal, Massachusetts Clean Peak Standard (CPS), and the Massachusetts Greenhouse Gas Emissions Standard (GGES) for municipal light plants are new policy additions that have been implemented since AESC 2021.[213] In 2023, Connecticut enacted Public Act 23-102 *An Act Strengthening Protections for Connecticut's Consumers of Energy*, which classifies nuclear power generating facility constructed on or after October 1, 2023, as a Class I resource, as well as permits 2.5 percent (increase from 1 percent) of the Class I RPS requirement to be met with "large-scale hydropower" should Connecticut DEEP find that there is a material shortage of Class I renewable energy sources and 2.5 percent (increase from 1 percent) of the Class I RPS requirement to be met with run-of-the-river hydropower facility that received a new license after January 1, 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,[214] 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 79 and Table 80.

213 Note that modeling of the CPS assumes full compliance.

214 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).

Schedule MM-R1

Table 78. Summary of RPS and CES classes

State	RPS Class or Tier	COD Threshold	Eligibility Notes
Connecticut	Class I	No threshold, except hydro which requires COD > 7/1/2003	Subject to emissions threshold; Allows nuclear power generating facilities constructed on or after October 1, 2023
	Class II	No threshold	Dedicated to WTE; Class I resources also eligible
	Class III	Beginning 1/1/2006 or 4/1/2007 (depending on system type)	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 I Thermal	Beginning 6/30/2019	Produced directly by a facility using sunlight, biomass, biogas or liquid biofuel or produced as a byproduct of electricity generated by a Class I or Class IA resource
	Class II	No threshold	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 and hydro from NH, CT, and eastern Canada
	CPS	No threshold	New MA-I, existing MA-I w/ storage, DRR
	GGES	Besides biomass fuel, no threshold	RPS Class I eligible technologies; biomass fuel (after 1/1/2026); landfill methane and anaerobic digester gas; nuclear energy; imported hydro; any generation yielding a 50% reduction in GHG relative to the operation of combined cycle natural gas generating facility over a 20-year life cycle
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

Schedule MM-R1

power, waste-to-energy, thermal resources, energy transformation, or energy efficiency. These classes are also included in Table 78 and their respective targets are summarized in Table 80. 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 2024 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 (adjusted for contract exemptions) by the applicable annual class-specific RPS percentage target.[215] The forecast of obligated load is based on the aggregate impact of conventional 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.[216] In all states, RPS targets are defined as a percentage of obligated load. Table 79 summarizes current RPS targets for new renewable energy additions, while Table 80 summarizes RPS targets for existing resource categories.

Several changes have occurred since the prior AESC analysis. In 2021, Massachusetts passed *An Act Creating A Next-Generation Roadmap for Massachusetts Climate Policy*, which created a "Greenhouse Gas Emissions Standard" (GGES). The GGES requires municipal utilities to meet a minimum target of 50 percent non-carbon emitting electricity in 2030, 75 percent in 2040, and 100 percent in 2050 and thereafter (see Table 78 for information on eligible "non-carbon emitting" resources).[217] While 2030 is the first year Massachusetts municipal utilities are required to comply with GGES obligation, some municipal utilities are expected to gradually increase their share of non-carbon emitting electricity earlier to mitigate the rate impact in 2030. In 2022, Rhode Island signed into law *An Act Relating to Public Utilities and Carriers-Renewable Energy*, which increased "New" targets incrementally starting in 2023 to reach 100 percent renewable electricity (98 percent New and 2 percent Existing) by 2033. Since AESC 2021, Connecticut has codified the mandate to be 100 percent carbon-free by 2040. Connecticut policymakers have not, however, established the annual Class I contributions toward this new target. This analysis assumes CT Class I target increases consistent with achieving 100 percent carbon-free by 2040.

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215 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.

216 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.

217 The GGES target schedule is defined as a step function with targets set only for 2030, 2040, and 2050. There are no interim targets before 2030 or between the three years.

Schedule MM-R1

Table 79. Summary of current RPS targets for new resource categories

	CT-I	ME-I	ME-IA	ME-I T	MA-I[218]	MA-SREC-I[219]	MA-SREC-II[220]	MA CES	MA CPS[221]	MA APS	NH-I[222]	NH-I T	NH-II	RI-New	VT-II	VT-III
2021	22.5%	10%	5%	0.4%	18%	1.66%	3.92%	22%	3.0%	5.25%	11.4%	1.8%	0.7%	15.5%	3.4%	4.67%
2022	24%	10%	8%	0.8%	20%	1.54%	4.07%	24%	4.5%	5.50%	12.3%	2.0%	0.7%	17%	4.0%	5.33%
2023	26%	10%	11%	1.2%	22%	0.93%	3.92%	26%	6.0%	5.75%	13.2%	2.2%	0.7%	21%	4.6%	6.00%
2024	28%	10%	15%	1.6%	24%	TBD	TBD	28%	7.5%	6.00%	14.1%	2.2%	0.7%	26%	5.2%	6.67%
2025	30%	10%	19%	2.0%	27%	TBD	TBD	30%	9.0%	6.25%	15%	2.2%	0.7%	32%	5.8%	7.33%
2026	32%	10%	23%	2.4%	30%	TBD	TBD	32%	10.5%	6.50%	15%	2.2%	0.7%	39%	6.4%	8.00%
2027	35%	10%	27%	2.8%	33%	TBD	TBD	34%	12.0%	6.75%	15%	2.2%	0.7%	46%	7.0%	8.67%
2028	38%	10%	31%	3.2%	36%	TBD	TBD	36%	13.5%	7.00%	15%	2.2%	0.7%	53.5%	7.6%	9.33%
2029	41%	10%	35%	3.6%	39%	TBD	TBD	38%	15.0%	7.25%	15%	2.2%	0.7%	61.5%	8.2%	10.0%
2030	44%	10%	40%	4.0%	40%	TBD	TBD	40%	16.5%	7.50%	15%	2.2%	0.7%	70%	8.8%	10.67%
2031	46.5%	10%	40%	4.0%	41%	TBD	TBD	42%	18.0%	7.75%	15%	2.2%	0.7%	79%	9.4%	11.33%
2032	50%	10%	40%	4.0%	42%	TBD	TBD	44%	19.5%	8.00%	15%	2.2%	0.7%	88.5%	10%	12.0%
2033	54%	10%	40%	4.0%	43%	TBD	TBD	46%	21.0%	8.25%	15%	2.2%	0.7%	98%	10%	12.0%
2034	58%	10%	40%	4.0%	44%	TBD	TBD	48%	22.5%	8.50%	15%	2.2%	0.7%	98%	10%	12.0%
2035	62%	10%	40%	4.0%	45%	TBD	TBD	50%	24.0%	8.75%	15%	2.2%	0.7%	98%	10%	12.0%
2036	67%	10%	40%	4.0%	46%	TBD	TBD	52%	25.5%	9.00%	15%	2.2%	0.7%	98%	10%	12.0%
2037	72%	10%	40%	4.0%	47%	TBD	TBD	54%	27.0%	9.25%	15%	2.2%	0.7%	98%	10%	12.0%
2038	77%	10%	40%	4.0%	48%	TBD	TBD	56%	28.5%	9.50%	15%	2.2%	0.7%	98%	10%	12.0%
2039	83%	10%	40%	4.0%	49%	TBD	TBD	58%	30.0%	9.75%	15%	2.2%	0.7%	98%	10%	12.0%
2040	89%	10%	40%	4.0%	50%	TBD	TBD	60%	31.5%	10.00%	15%	2.2%	0.7%	98%	10%	12.0%
2041	89%	10%	40%	4.0%	51%	TBD	TBD	62%	33.0%	10.25%	15%	2.2%	0.7%	98%	10%	12.0%
2042	89%	10%	40%	4.0%	52%	TBD	TBD	64%	34.5%	10.50%	15%	2.2%	0.7%	98%	10%	12.0%
2043	89%	10%	40%	4.0%	53%	TBD	TBD	66%	36.0%	10.75%	15%	2.2%	0.7%	98%	10%	12.0%
2044	89%	10%	40%	4.0%	54%	TBD	TBD	68%	37.5%	11.00%	15%	2.2%	0.7%	98%	10%	12.0%
2045	89%	10%	40%	4.0%	55%	TBD	TBD	70%	39.0%	11.25%	15%	2.2%	0.7%	98%	10%	12.0%
2046	89%	10%	40%	4.0%	56%	TBD	TBD	72%	40.5%	11.50%	15%	2.2%	0.7%	98%	10%	12.0%
2047	89%	10%	40%	4.0%	57%	TBD	TBD	74%	42.0%	11.75%	15%	2.2%	0.7%	98%	10%	12.0%
2048	89%	10%	40%	4.0%	58%	TBD	TBD	76%	43.5%	12.00%	15%	2.2%	0.7%	98%	10%	12.0%
2049	89%	10%	40%	4.0%	59%	TBD	TBD	78%	45.0%	12.25%	15%	2.2%	0.7%	98%	10%	12.0%
2050	89%	10%	40%	4.0%	60%	TBD	TBD	80%	46.5%	12.50%	15%	2.2%	0.7%	98%	10%	12.0%

[218] This is the gross MA-I target. The MA-SREC target is carved out of the MA-I target.

[219] Without exemptions for load under contract.

[220] Without exemptions for load under contract.

[221] This is the initial target trajectory, which is subject to modifications based on market conditions.

[222] This is the gross NH-I target. The NH-I Thermal target is carved out of the NH-I target.

Schedule MM-R1

Table 80. Summary of RPS targets for other resource categories

	CT-II[(a)]	CT-III	ME-II	MA-II Non-WTE	MA-II WTE	MA CES-E[(b)]	NH-III[(c)]	NH-IV	RI-Existing	VT-I[(d)]
2021	4%	4%	30%	3.56%	3.7%	20%	8%	1.5%	2%	55.6%
2022	4%	4%	30%	3.6%	3.7%	20%	8%	1.5%	2%	55%
2023	4%	4%	30%	3.47%	3.7%	20%	8%	1.5%	2%	58.4%
2024	4%	4%	30%	3.6%	3.7%	20%	8%	1.5%	2%	57.8%
2025	4%	4%	30%	TBD	3.7%	20%	8%	1.5%	2%	57.2%
2026	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	60.6%
2027	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	60%
2028	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	59.4%
2029	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	62.8%
2030	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	62.2%
2031	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	61.6%
2032	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2033	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2034	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2035	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2036	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2037	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2038	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2039	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2040	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2041	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2042	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2043	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2044	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2045	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2046	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2047	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2048	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2049	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%
2050	4%	4%	30%	TBD	3.5%	20%	8%	1.5%	2%	65%

Notes: RPS target assumptions are based on current law.
(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 tied 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

Several material changes to alternative compliance payment mechanisms have occurred since the AESC 2021 analysis, and which impact market dynamics, REC prices, and the manner in which states will meet RPS obligations during the AESC 2024 study period.

In 2021, Massachusetts amended its Class I ACP schedule to be phased down to $50 per MWh in 2022 and $40 per MWh in 2023 and thereafter. In 2022, Massachusetts retroactively amended its CES and CES-E ACP schedules, which were previously indexed to the Class I ACP, to be fixed at $35 per MWh and $10 per MWh respectively, starting 2022. In 2023, Maine enacted Chapter 361, which directed the Maine PUC to update the Class II ACP to no greater than $10 per MWh. In November 2023, the PUC established a Class II ACP of $5/MWh (fixed and flat). Table 81 provides a summary of ACP values for

Schedule MM-R1

each RPS category. Note that some ACP values stay constant (in nominal terms) throughout the study period, while other values change over time.

Table 81. Summary of Alternative Compliance Payment levels

		2023 Alternative Compliance Payment (nominal $ per MWh)	Notes
CT	Class I	$40.00	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	$40.00	Fixed and flat.
	Solar Carve-out I	$330.00	Schedule set by DOER.
	Solar Carve-out II	$271.00	Schedule set by DOER.
	CPS	$45.00	Fixed and flat through 2024. Decline by $1.54 each year thereafter. Trajectory subject to modifications based on market conditions.
	Class II – RE	$33.06	Adjusted by CPI each year.
	Class II – WTE	$33.06	Adjusted by CPI each year.
	APS	$23.50	Adjusted by CPI each year.
	CES	$35.00	75% of Class I ACP in 2020, 50% in 2021, and $35/MWh thereafter.
	CES-E	$10.00	10% of Class I ACP in 2021, and $10/MWh thereafter.
RI	New	$80.59	Adjusted by CPI each year.
	Existing	$80.59	Adjusted by CPI each year.
ME	Class I	$50.00	Fixed and flat.
	Class II	$5.00	Fixed and flat.
NH	Class I	$61.18	Adjusted by ½ of CPI each year.
	Class I - Thermal	$27.80	Adjusted by ½ of CPI each year.
	Class II	$61.18	Adjusted by ½ of CPI each year.
	Class III	$38.89	Adjusted by CPI each year.
	Class IV	$32.72	Adjusted by CPI each year.
VT	Tier I	$11.97	Adjusted by CPI each year.
	Tier II	$71.83	Adjusted by CPI each year.
	Tier III	$71.83	Adjusted by CPI each year.

The ACP rate modifications explained above have substantive impacts on market dynamics and the achievement of regional RPS compliance. While RPS compliance can technically be achieved either through the procurement and retirement of renewable energy or through alternative compliance payments, the latter does not impact the regional fuel mix or contribute towards the achievement of GHG emissions targets or renewable and clean energy policy objectives more generally. In addition, the ACP—by definition—serves as a price cap on RECs, ostensibly as a ratepayer protection mechanism. If the expected value of energy, capacity, and RECs is not equal to or greater than a renewable energy generator's revenue requirement, however, the facility will not be able to secure the financing necessary for construction. Therefore, if the ACP rate is too low it will be a barrier to new market entry. Such conditions would likely cause state regulators to increase long-term procurement authority and purchasing – which, through bundled contracts, implicitly avoid the ACP limitation. Therefore, to ensure

Schedule MM-R1

that states meet their policy targets with renewable energy, this analysis assumes that incremental state procurement is deployed at volumes necessary to avoid reliance on ACPs for policy compliance.

Market condition changes

Numerous changes have occurred in the market since the publication of AESC 2021 that influence renewable energy deployment and the avoided cost of RPS compliance.

The IRA, now Public Law 117-169, makes significant climate and clean energy investments, largely through expansion and extension of tax credits, including those assumed to be phased out during the course of the analysis period for AESC 2021. For land-based wind, offshore wind, solar, qualified hydropower, and tidal resource, our projection of long-term cost of entry assumes that modeled resources will meet the prevailing wage and apprenticeship requirements to receive the full (base + bonus) statutory investment and production credits throughout the analysis period. [223,224] We do not expect these requirements to have material cost impact for renewable energy projects in New England. The IRA also offers various additional bonus credits. Our analysis assumes that all modeled resources will leverage the bonus credit for domestic content, but a portion of the benefit will be offset by the incremental cost of utilizing steel and other materials or subcomponents manufactured in the United States. Distributed solar and offshore wind projects may also be able to leverage bonus credits for locating on brownfields and serving energy communities. This could improve project economics and the overall success of state-sponsored clean energy programs.

While the IRA extended and expanded economic support for renewable development, a combination of unprecedented global, national, and regional constraints—triggered by the COVID-19 pandemic and Ukraine War—have challenged renewable energy development since the release of AESC 2021. These factors, which include supply chain constraints, inflation, interest rates, labor and service shortages, vendor pricing power, and continued interconnection and permitting process delays, have exerted material cost pressure on renewable development and caused significant delays and project failures across New England. We have reflected the impacts of these costs and delays on near-term supply-demand (pipeline project completion timing and attrition) and the long-term cost of entry (renewable resource costs) in this analysis using assumptions derived from project-specific research, interviews with market stakeholders such as developers and investors, and public sources (e.g., EIA's AEO).

[223] The IRA sets a "base credit" value for all relevant production and investment credits equivalent to 20 percent of the full statutory credit values (of 30 percent and 2.5¢ per kWh (plus inflation adjustment. Eligible projects would be eligible to earn "bonus credit" to receive the full credit value (equal to 100 percent of the full statutory investment and production credit values) if applicable prevailing wage and apprenticeship requirements are met.

[224] The IRA Clean Energy Production Credit and Clean Energy Investment Credit would phase out either at the end of 2032 or when electric power section emissions are 75 percent below 2022 levels (as calculated on a national basis), whichever is later. AESC 2024 assumes that the phase-out would occur in a timeline that does not affect the resources considered for this analysis.

7.2. Renewable Energy Certificate (REC) price forecasting

This section summarizes REC price forecasting outcomes. Class I, 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 broker quotes, which is comprised of both consummated transactions and bid-ask spreads in periods where transactions were not reported. For reference, Table 82 shows annual average historical REC prices for new RPS markets. Table 83 shows historical REC prices for existing RPS markets.

Table 82. Annual average historical REC prices, New supply: 2015–2023 (nominal $ per MWh)

		2015	2016	2017	2018	2019	2020	2021	2022	2023
CT	Class I	$44	$22	$12	$8	$35	$36	$35	$39	$39
MA	Class I	$44	$22	$12	$8	$35	$37	$35	$39	$39
	APS	$21	$21	$20	$17	$9	$1	$15	$19	$8
	CES	NA	NA	NA	NA	NA	NA	NA	NA	NA
RI	New	$43	$23	$12	$7	$34	$34	$35	$39	$39
ME	Class I & IA	$18	$22	$8	$3	$2	$12	$15	$37	$36
NH	Class I	$45	$24	$12	$8	$35	$34	$35	$39	$39
	Class II - Solar	$51	$43	$26	$13	$27	$36	$36	$38	$38
VT	Tier II	NA	NA	NA	NA	NA	NA	NA	NA	NA
	Tier III	NA	NA	NA	NA	NA	NA	NA	NA	NA

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

Schedule MM-R1

Table 83. Annual average historical REC prices, Existing supply: 2015–2023 (nominal $ per MWh)

		2015	2016	2017	2018	2019	2020	2021	2022	2023
CT	Class II	$1	$1	$7	$6	$20	$18	$20	$24	$24
	Class III	$27	$27	$26	$26	$22	$9	$11	$27	$27
MA	Class II – Non-WTE	$27	$26	$26	$26	$23	$28	$28	$31	$29
	Class II – WTE	$6	$6	$6	$6	$10	$6	$15	$18	$23
	CES-E	NA	NA	NA	NA	NA	$2.75	$4	$5	$10
RI	Existing	$1	$1	$1	$1	$1	$2	$6	$3	$2
ME	Class II	$0	$1	$1	$1	$1	$2	$6	$3	$2
NH	Class III	$37	$28	$23	$13	$40	$38	$34	$34	$34
	Class IV	$25	$25	$25	$26	$26	$26	$27	$29	$29
VT	Tier I	NA	NA	NA	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 REC price is the key input to calculating the avoided cost of RPS compliance. The Synapse Team forecasts Class I REC prices using the New England Renewable Energy Market Outlook (REMO).[225] 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 2023 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 79. 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.

[225] See Section 4.1: *AESC 2024 modeling framework* for more information.

Schedule MM-R1

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 the policies described in Table 85.

Table 84. Renewable policies modeled in AESC 2024

Topic	Background information known as of the start of the AESC 2024 study	Relevant assumptions for AESC 2024
RPS Targets and ACPs		
ME Class II ACP	Chapter 361 of 2023 directs the PUC to set the ME-II ACP	PUC set the ME Class II ACP at $5/MWh
MA CPS Targets & ACP	MA CPS targets & ACP are subject to adjustments based on market conditions	Assume no adjustments; use initial trajectories
CT Class I Targets	100% 'carbon-free' by 2040 goal codified since AESC 2021; CT-I target adjustment has not been specified and depends on contribution of nuclear and large hydro	Assume CT-I target increase starting 2029, consistent with law being primarily fulfilled by Class I resources
RI RES	Enacted 100% by 2033 (98% "New") since AESC 2021	Model law, assume no further adjustments
VT RES	Legislature expected to take up 100% RES or CES bill in 2024 session	Assume no adjustments; modeling RES policy as it exists as of September 2023
Near-Term Large-Scale Supply		
MA Sec. 83D Hydro Procurement	AESC 2021 assumed delivery of 9.45 TWh beginning 7/1/2023	Assume delivery of 9.45 TWh beginning 1/1/2027
MA Sec. 83C OSW Procurement: Vineyard Wind (804.5 MW)	AESC 2021 assumed COD 9/1/2024	Assume COD 8/1/2024
MA Sec. 83C OSW Procurement: South Coast Wind 1&2 (804 MW, f.k.a Mayflower Wind)	AESC 2021 assumed COD 1/1/2026; Project indicated intent to terminate contract	Assume project would rebid in subsequent MA Sec. 83C OSW RFP and get selected; COD 6/1/2029
MA Sec. 83C OSW Procurement: South Coast Wind 3 (400 MW)	Project selected in 2021; recently indicated intent to terminate contract	Assume project would rebid in subsequent MA Sec. 83C OSW RFP and get selected; COD 11/1/2029
MA Sec. 83C OSW Procurement: Commonwealth Wind (1232 MW)	Project selected in 2021; recently indicated intent to terminate contract	Assume project would rebid in subsequent MA Sec. 83C OSW RFP and get selected; COD 9/1/2029
CT & RI Joint OSW Procurement: Revolution Wind (700 MW)	AESC 2021 assumed COD 7/1/2025	Assume COD 6/1/2025
CT OSW Procurement: Park City Wind (804 MW)	AESC 2021 assumed COD 1/1/2026	Assume COD 3/1/2028
ME Tranche 1 and Tranche 2 Procurement	AESC 2021 assumed 1 TWh by 2025; there has since been multiple delays and termination	Probability of success and timing assumed on a project-specific basis
ME and MA joint Northern ME Transmission + Generation	RFP issued in 2021; Projects selected in 2022	Assume COD 1/1/2029

Topic	Background information known as of the start of the AESC 2024 study	Relevant assumptions for AESC 2024
Procurement: 1,000 MW King Pine Wind + 1,200 MW Aroostook Renewable Gateway		
Additional Procurement		
CT Additional Zero-Carbon Procurement	Issued draft RFP for all remaining authority (3.9 TWh) in 2023	Assume procurement of 300 MW solar equivalent to 'backfill' for contract attrition plus additional 105 MW
ME LT Procurement	Chapter 371 of 2023 authorizes procurement of "unfulfilled" capacity of 1,200 MW Aroostook Renewable Gateway	Assume procurement of additional wind/solar supply on transmission line to reflect, in combination with King Pine Wind, a total delivery of 4.73 TWh (1,200 MW at 45% capacity factor) starting 1/1/2029
ME LT Procurement	Chapter 321 of 2023 authorizes procurement of ME-IA resources of up to 5% of retail load, plus amount contracted under previous procurements that are determined to be unfulfilled, with primary preference to resources on contaminated lands	Assume procurement of a % less than 5% that reflects resource potential available on contaminated land
NH LT Procurement	SB 54, enacted in 2023, directs EDCs to procure up to 2 million MWhs by no later than 6/30/2025	Assume NH will not procure under current development cost environment
MA Additional Offshore Wind Procurement		Models remaining authority of 4,800 MW
CT Additional Offshore Wind Procurement		Models remaining authority of 1,196 MW
RI Additional Offshore Wind Procurement		Models remaining authority of 1,000 MW
ME Offshore Wind Procurement	Chapter 481 of 2023 authorizes 3 GW of OSW procurement by 2040	Assume none for the Reference Case; Will reach out to ME Study Group representatives to confirm assumption and discuss alternative assumptions for other cases.
Distributed Generation		
SMART Successor	AESC 2021 modeled 2,000 MW SMART expansion per legislative proposal; the specific provision did not pass, but there continues to be ongoing discussion on additional DG solar policy	Assume 2,000 MW SMART successor
RI REG Extension	AESC 2021 modeled RI REG plus extension	Same approach as AESC 2021
ME DG Solar Policy	DG procurement modeled in AESC 2021 was ruled uncompetitive; ME considering DG policy successors	Assume implementation of NEB successor
CT RRES and Successor	A residential tariff has been developed to succeed the RRES Program	Model extends the RRES build rate for duration of study period.
CT NRES and Successor	A successor tariff has been developed to succeed the NRES Program	Model extends the NRES program (for the duration of the study period) at 80% of the current build rate

Schedule MM-R1

Given the eligibility interaction between the MA CES and MA Class I RPS markets, we modeled REC and Clean Energy Credit (CEC) price forecasts interdependently. RECs and ACPs used for Massachusetts Class I compliance are counted toward CES compliance. Incremental CES demand above the Massachusetts Class I RPS are satisfied first by non-RPS eligible large hydro resources delivered over new transmission lines (once available), and second by a combination of Class I resources and Massachusetts CES ACPs, depending on regional Class I supply availability.

The Synapse Team allocated forecasted Class I REC supply 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. We use each state's resulting supply-demand balance, banking balances, ACPs, and forward-looking market dynamics 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 ACP (which acts as a price cap).
- Substantial market surplus, or even modest market surplus without banking: Prices crash to approximately $2/MWh, reflecting transaction and risk management costs.
- Market surplus with banking: Prices tend towards the cost of entry, discounted by factors including the time-value of money, the amount of banking that has taken place, expectations of when the market will return to equilibrium, and other risk management factors.

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 construct 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 1,405 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 Annual Technology Baseline) 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.[226] While utility-scale solar is the largest potential resource by

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

Schedule MM-R1

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.

We model resources from the supply curve 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,[227] 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,[228] transmission network upgrade costs,[229] and wind integration costs.

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 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 based on the modeled effective load carrying capability for each technology, 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 subtract (a) the nominal levelized value of production consistent with the AESC 2024 projection of wholesale electric energy and capacity prices from (b) nominal levelized cost of marginal resources.[230] 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.

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[227] 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.

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

[229] It is assumed that 15–33 percent of the transmission costs are socialized and thereby not borne by the generators.

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

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 on a real-dollar basis 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.

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 are based on preliminary energy and capacity forecasts and are then used to inform final energy and capacity prices. These final prices are inputs for the final REC price and avoided RPS compliance cost calculation.

Class I 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.[231]

The supply curve consists of land-based wind, offshore wind, utility-scale solar, biomass,[232] 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:

[231] 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.

[232] Including biogas and biodiesel.

Schedule MM-R1

- 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 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.[233] The analysis assumes the full federal tax incentives under the IRA of 2022.[234] 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, utilizing AESC 2024 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 are modeled independently and netted from gross demand.

Table 85 summarizes the projection of the cost of new entry (REC premium) for each new RPS category for Counterfactual #1. We assume CEC prices for the Massachusetts CES track MA-I REC prices unless capped by the CES ACP of $35 per MWh until CES-eligible hydro comes online (in 2027). Thereafter, when hydro contracted under MA Sec. 83D can be used to fulfill a portion of the CES obligation, we

[233] We assume that reinforcement of major transmission facilities (e.g., improved connections between Maine and the rest of New England) will be socialized.

[234] U.S. Department of Energy. Last accessed August 23, 2023. "Inflation Reduction Act of 2022." *Energy.gov.* Available at https://www.energy.gov/lpo/inflation-reduction-act-2022.

assume a price of $0 for that portion of compliance 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.

Table 85. REC premium for market entry (2024 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2024	$37.00	$37.00	$37.00	$23.75	$37.00	$34.48	$42.75
2025	$36.20	$36.20	$36.20	$23.24	$36.74	$33.73	$41.83
2026	$35.42	$35.42	$35.42	$22.73	$35.42	$33.00	$40.92
2027	$36.90	$39.33	$39.33	$22.24	$36.90	$1.88	$40.03
2028	$36.10	$38.48	$38.48	$21.76	$36.10	$1.84	$39.17
2029	$27.28	$27.28	$27.28	$21.29	$27.30	$27.28	$38.32
2030	$25.34	$25.34	$25.34	$20.83	$25.34	$25.35	$37.49
2031	$31.75	$31.75	$31.75	$20.38	$31.75	$29.05	$32.82
2032	$23.59	$23.59	$23.59	$19.94	$23.59	$23.60	$32.11
2033	$23.09	$23.09	$23.09	$19.51	$23.09	$23.09	$31.41
2034	$24.97	$24.97	$24.97	$19.08	$24.97	$21.96	$30.73
2035	$27.39	$27.17	$27.17	$18.67	$27.39	$21.31	$30.07
2036	$29.69	$30.16	$30.16	$18.27	$29.69	$22.48	$29.42
2037	$29.65	$30.81	$30.81	$17.87	$29.65	$24.18	$28.78
2038	$29.01	$31.04	$31.04	$17.48	$29.01	$25.38	$28.16
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2024	$13.81	$37.00	$25.30	$37.00	$37.00	$37.00	$25.30
2025	$13.81	$36.20	$25.02	$36.74	$36.20	$36.20	$25.02
2026	$13.81	$35.42	$24.75	$35.42	$35.42	$35.42	$24.75
2027	$13.81	$39.33	$24.48	$36.90	$39.33	$39.33	$24.48
2028	$13.81	$38.48	$24.22	$36.10	$38.48	$38.48	$24.22
2029	$13.81	$27.28	$23.96	$27.30	$27.28	$27.28	$23.96
2030	$13.81	$25.34	$23.70	$25.34	$25.34	$25.34	$23.70
2031	$13.81	$31.75	$19.54	$31.75	$31.75	$31.75	$19.54
2032	$13.81	$23.59	$19.32	$23.59	$23.59	$23.59	$19.32
2033	$13.81	$23.09	$19.11	$23.09	$23.09	$23.09	$19.11
2034	$13.81	$24.97	$18.91	$24.97	$24.97	$24.97	$18.91
2035	$13.81	$27.17	$18.70	$27.39	$27.17	$27.17	$18.70
2036	$13.81	$30.16	$18.50	$29.69	$30.16	$30.16	$18.50
2037	$13.81	$30.81	$18.30	$29.65	$30.81	$30.81	$18.30
2038	$13.81	$31.04	$18.10	$29.01	$31.04	$31.04	$18.10

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.

Schedule MM-R1

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 86 describes how we forecast REC prices for non-Class I markets.

Table 86. 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 expected to remain modestly below the ACP.
ME Class II	REC prices are estimated based on current broker quotes, consider the interaction with other "existing" markets, and limitations imposed by the new $5/MWh ACP.
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	Assumes current REC prices are indicative of long-term equilibrium.
MA CPS	CPEC prices are assumed to track the CPS ACP through 2030, which would be consistent with a persistent shortage. In the long term, CPEC prices are forecasted as 85% of the MA CPS ACP.
MA CES	Costs associated with CECs derived from MA 83D hydro supply are not avoidable. For all incremental CES obligations, CEC prices are the lesser of the MA Class I price and the CES ACP.
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 100% 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 based on expected market dynamics.
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 90 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 87 shows our projection of REC prices for existing resource categories. For reference, Table 83 shows annual average historical REC prices for Existing RPS markets.

Schedule MM-R1

Table 87. Summary of REC prices for existing resource categories (2024 $ 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
2024	$24.92	$26.88	$4.13	$27.67	$23.88	$8.69	$37.18	$27.67	$4.75	$4.13
2025	$24.46	$26.23	$4.46	$25.34	$23.88	$8.32	$37.20	$25.34	$5.87	$4.46
2026	$25.84	$25.43	$4.67	$25.34	$23.88	$8.14	$37.25	$25.34	$6.82	$4.67
2027	$22.24	$24.68	$4.45	$25.34	$23.88	$7.96	$37.35	$25.34	$6.20	$4.45
2028	$21.76	$24.14	$4.35	$25.34	$23.88	$7.79	$37.46	$25.34	$6.07	$4.35
2029	$21.29	$23.62	$4.26	$25.34	$23.88	$7.62	$37.56	$25.34	$5.94	$4.26
2030	$20.83	$23.11	$4.17	$25.34	$23.88	$7.45	$37.62	$25.34	$5.81	$4.17
2031	$20.38	$22.61	$4.08	$25.34	$23.88	$7.29	$37.67	$25.34	$5.68	$4.08
2032	$19.94	$22.12	$3.99	$23.59	$23.88	$7.14	$37.69	$23.59	$5.56	$3.99
2033	$19.51	$21.64	$3.90	$23.09	$23.88	$6.98	$37.71	$23.09	$5.44	$3.90
2034	$19.08	$21.17	$3.82	$24.97	$23.88	$6.83	$37.74	$24.97	$5.32	$3.82
2035	$18.67	$20.71	$3.73	$25.34	$23.88	$6.68	$37.77	$25.34	$5.21	$3.73
2036	$18.27	$20.27	$3.65	$25.34	$23.88	$6.54	$37.79	$25.34	$5.10	$3.65
2037	$17.87	$19.83	$3.57	$25.34	$23.88	$6.40	$37.83	$25.34	$4.99	$3.57
2038	$17.48	$19.40	$3.50	$25.34	$23.88	$6.26	$37.87	$25.34	$4.88	$3.50

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

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

Where:

i = year

n = RPS classes

$P_{n,i}$ = projected price of RECs for RPS class n in year i,

$R_{n,i}$ = RPS requirement, expressed as a percentage, for RPS class n in year i,

l = losses from ISO wholesale load accounts to retail meters (modeled at 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.

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

Schedule MM-R1

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.

Table 88 shows the avoided cost of RPS compliance aggregated for all new and other categories, for Counterfactual #1. Table 89 and Table 90 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. Results for all other counterfactuals can be found in the Excel-based AESC 2024 *User Interface*.

Table 88. Avoided cost of RPS compliance for Counterfactual #1 (2024 $ per MWh)

	CT	ME	MA	NH	RI	VT
New Renewable / Clean Procurement Obligations	$15.36	$14.29	$13.32	$5.28	$22.62	$2.78
All Existing Procurement Obligations	$0.92	$1.33	$3.73	$3.69	$0.12	$2.75
All Other Compliance Obligations	$1.00	$0.75	$7.54	$3.00	$0.00	$2.37
Total	**$16.16**	**$16.25**	**$23.84**	**$11.92**	**$21.54**	**$7.78**

Note: A compliance obligation differs from a procurement obligation in that while it is expressed as a percent of retail sales, the certificates purchased do not represent electricity used to serve retail load.

Schedule MM-R1

Table 89. Summary of avoided cost of RPS compliance, New RPS categories (2024 $ per MWh)

	CT-I	ME-I	ME-IA	ME-T	MA-I	MA CES	MA CPS
2024	$11.29	$4.03	$6.05	$0.41	$8.19	$1.50	$3.49
2025	$11.86	$3.95	$7.50	$0.51	$9.37	$1.10	$4.10
2026	$12.48	$3.86	$8.88	$0.59	$10.77	$2.16	$4.68
2027	$13.92	$4.29	$11.58	$0.68	$12.65	$0.00	$5.24
2028	$14.41	$4.19	$13.00	$0.76	$14.17	$0.00	$5.76
2029	$12.88	$3.20	$11.22	$0.84	$12.59	$0.00	$6.27
2030	$12.00	$2.78	$11.10	$0.91	$11.10	$0.99	$6.74
2031	$15.67	$3.37	$13.48	$0.89	$13.82	$1.28	$6.44
2032	$12.93	$2.59	$10.34	$0.87	$10.86	$1.17	$6.82
2033	$14.12	$2.63	$10.51	$0.85	$11.29	$1.32	$7.19
2034	$15.94	$2.76	$11.03	$0.83	$12.13	$1.40	$7.54
2035	$16.40	$3.06	$12.24	$0.81	$11.87	$1.35	$7.87
2036	$17.19	$3.38	$13.54	$0.80	$11.91	$1.33	$8.18
2037	$16.49	$3.09	$12.35	$0.78	$10.86	$1.35	$8.47
2038	$18.08	$2.72	$10.88	$0.76	$11.30	$1.57	$8.75
Levelized (2024-2038)	**$14.24**	**$3.36**	**$10.82**	**$0.75**	**$11.50**	**$1.09**	**$6.39**
	MA APS	**NH-I**	**NH-I Thermal**	**NH-II**	**RI-New**	**VT-II**	**VT-III**
2024	$0.90	$5.69	$3.28	$0.28	$10.49	$2.10	$1.84
2025	$0.94	$5.92	$3.49	$0.28	$12.63	$2.29	$2.00
2026	$0.98	$5.79	$3.45	$0.27	$15.06	$2.47	$2.16
2027	$1.02	$6.43	$3.42	$0.28	$19.72	$3.00	$2.31
2028	$1.05	$6.29	$3.38	$0.28	$22.44	$3.19	$2.46
2029	$1.09	$4.81	$3.34	$0.23	$19.71	$2.63	$2.61
2030	$1.13	$4.16	$3.31	$0.19	$19.43	$2.44	$2.76
2031	$1.17	$5.06	$2.73	$0.24	$26.63	$3.17	$2.41
2032	$1.20	$3.88	$2.70	$0.18	$22.89	$2.59	$2.53
2033	$1.24	$3.94	$2.67	$0.18	$25.74	$2.63	$2.50
2034	$1.28	$4.14	$2.64	$0.19	$27.02	$2.76	$2.47
2035	$1.32	$4.59	$2.61	$0.18	$29.99	$3.06	$2.45
2036	$1.36	$5.08	$2.58	$0.18	$27.89	$2.85	$2.42
2037	$1.39	$4.63	$2.55	$0.16	$25.10	$2.56	$2.39
2038	$1.43	$4.08	$2.53	$0.16	$21.61	$2.21	$2.37
Levelized (2024-2038)	**$1.15**	**$5.01**	**$3.00**	**$0.22**	**$21.42**	**$2.66**	**$2.37**

Schedule MM-R1

Table 90. Summary of avoided cost of RPS compliance, Existing RPS categories (2024 $ 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
2024	$1.09	$1.17	$1.35	$1.09	$0.96	$2.56	$3.24	$0.45	$0.10	$2.60
2025	$1.07	$1.14	$1.46	$0.99	$0.96	$2.36	$3.24	$0.41	$0.13	$2.78
2026	$1.13	$1.11	$1.53	$0.99	$0.91	$2.22	$3.25	$0.41	$0.15	$3.08
2027	$0.97	$1.08	$1.45	$0.99	$0.91	$2.17	$3.26	$0.41	$0.14	$2.91
2028	$0.95	$1.05	$1.42	$0.99	$0.91	$2.04	$3.27	$0.41	$0.13	$2.82
2029	$0.93	$1.03	$1.39	$0.99	$0.91	$1.99	$3.27	$0.41	$0.13	$2.91
2030	$0.91	$1.01	$1.36	$0.99	$0.91	$1.87	$3.28	$0.41	$0.13	$2.82
2031	$0.89	$0.99	$1.33	$0.99	$0.91	$1.75	$3.28	$0.41	$0.12	$2.74
2032	$0.87	$0.96	$1.30	$0.93	$0.91	$1.71	$3.29	$0.39	$0.12	$2.83
2033	$0.85	$0.94	$1.28	$0.95	$0.91	$1.60	$3.29	$0.39	$0.12	$2.76
2034	$0.83	$0.92	$1.25	$0.99	$0.91	$1.49	$3.29	$0.41	$0.12	$2.70
2035	$0.81	$0.90	$1.22	$0.95	$0.91	$1.38	$3.29	$0.40	$0.11	$2.65
2036	$0.80	$0.88	$1.19	$0.93	$0.91	$1.35	$3.30	$0.39	$0.11	$2.59
2037	$0.78	$0.86	$1.17	$0.83	$0.91	$1.25	$3.30	$0.34	$0.11	$2.53
2038	$0.76	$0.85	$1.14	$0.84	$0.91	$1.16	$3.30	$0.35	$0.11	$2.48
Levelized (2024-2038)	**$0.92**	**$1.00**	**$1.33**	**$0.97**	**$0.92**	**$1.82**	**$3.28**	**$0.40**	**$0.12**	**$2.75**

Schedule MM-R1

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 2024 modeling of avoided energy costs. In contrast, costs associated with RGGI and Massachusetts' 310 CMR 7.74 and 7.75 regulations are included in the AESC 2024 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 we model these costs).

Because different states participating in the AESC study have differing policy contexts, we offer three different options and approaches for calculating the non-embedded GHG cost. AESC 2024 provides these approaches to enable individual states to address specific policy directives regarding GHG impacts. Table 91 and Table 92 compares these four values to values described in AESC 2021.

- A "damage cost" approximated by the SCC. An SCC should apply low discount rates, consider global damages, and consider the impact of extreme weather events. The Synapse Team recommends the set of SCC values published by U.S. EPA in November 2022. We recommend a 15-year levelized SCC in the range of $249 to $415 per short ton of CO_2 in AESC 2024, with this range reflecting a choice between a 2.0 percent for the lower cost and a 1.5 percent discount rate for the higher cost. This can be compared to AESC 2021's recommend value of $144 per short ton of CO_2. We also recommend the inclusion of analogous social costs of two other GHGs: CH_4 and N_2O, both of which we describe later in this section.

- An approach based on marginal abatement costs, assuming a cost derived from electric sector technologies likely to be built in New England. In AESC 2024, this is a total environmental cost of $185 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 $141 per short ton of CO_2-eq emissions (in 2024 dollars) based on a projection of future costs of offshore wind energy, as described in AESC 2021. Differences in prices are largely related to an adjusted projection of the cost of this technology.

- An approach based on New England marginal abatement costs, assuming a cost derived from multiple sectors. In AESC 2024, this is a total environmental cost of $581 per short ton of CO_2-eq emissions, based on a projection of future cost trajectories for renewable natural gas (RNG).. In AESC 2021, we had estimated a total environmental cost of $557 per short ton of CO_2-eq emissions (in 2024 dollars). This projected value in AESC 2024 is lower due to (a) different considerations of RNG feedstock and (b) updated information on costs and potentials of RNG feedstock 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).

Schedule MM-R1

Table 91. Comparison of GHG costs under different approaches (2024 $ per short ton) in Counterfactual #1

	AESC 2021	AESC 2024	Difference	% Difference
Social cost of greenhouse gases (SC-GHG or "damage cost") at 1.5% and 2% discount rates	$144 (2% only)	$249 to 415	$104 to 270	72 to 187%
New England-based marginal abatement cost, derived from the electric sector	$141	$185	$44	31%
New England-based marginal abatement cost, derived from multiple sectors	$557	$581	$24	4%

Notes: All values shown are levelized over 15 years. All AESC 2024 values except the SCC are levelized using a 1.74 percent discount rate (the 2.0 percent SCC is levelized using a 2.0 percent discount rate, while the 1.5 percent SCC is levelized using a 1.5 percent discount rate). All AESC 2021 values are levelized using a 0.81 percent discount rate, except SCC which uses a 2 percent discount rate, then converted into 2024 dollars. Values shown above remove energy prices, but not embedded costs. Values shown above do not include T&D losses.

Table 92. Comparison of GHG costs under different approaches (2024 cents per kWh) in Counterfactual #1

	AESC 2021	AESC 2024	Difference	% Difference
Social cost of greenhouse gases (SC-GHG or "damage cost") at 1.5% and 2% discount rates	5.50 (2% only)	8.95 to 15.37	3.45 to 9.88	63 to 180%
New England-based marginal abatement cost, derived from the electric sector	5.35	6.47	1.11	21%
New England-based marginal abatement cost, derived from multiple sectors	22.25	21.71	-0.56	-2%

Notes: Values shown above remove embedded costs (e.g., RGGI, MA 310 7.74, MA 310 7.75). All values quoted use a summer on-peak seasonal marginal emission rate and include a 9 percent energy loss factor. All values shown are only inclusive of point-of-consumption CO2 GHGs and do not include upstream GHGs or GHG cost impacts related to CH4 or N2O.

Depending on the relevant state's policy context, an AESC user may wish to include a non-embedded cost to fully account for the cost of GHG impacts or GHG abatement. To do this, we must first subtract out both the RGGI cost (in Connecticut, Maine, New Hampshire, Rhode Island, or Vermont) or the RGGI cost, and 310 CMR 7.74 and 7.75 costs (in Massachusetts only) from the relevant GHG emission cost to determine the remaining cost that is non-embedded.[235]

In general, AESC users should use a consistent approach for estimating non-embedded GHG avoided costs for all measures analyzed. For example, users should not apply a social cost of GHGs to some measures in a portfolio (or just the electric savings associated with a measure) and a marginal abatement cost to other measures (or the associated gas savings associated with an electric measure).

See *Appendix B: Detailed Electric Outputs* and *Appendix G: Marginal Emission Rates* for more detail on emission rate results and costs.

[235] We do not subtract compliance costs related to Section 111 of the *Clean Air Act*, for reasons discussed below.

Schedule MM-R1

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 EPA's proposed regulation under Section 111 of the *Clean Air Act*. 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 2024, we focus on the likely costs expected in the timeframe of 2024 through 2050.

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.)

AESC 2024 study group participants provided feedback on the types of non-embedded GHG costs used in recent planning studies. Table 93 describes these findings. We note that these historical decisions will not necessarily be made in the future, and that policymakers may decide to use different approaches for estimating non-embedded GHG costs in future planning.

Table 93. Non-embedded GHG costs used in recent planning processes

	CT	MA	ME	NH	RI	VT
Social cost of GHGs		Yes, for some measures				Yes, for all measures
Regional marginal abatement cost (based on electric sector resources)	Yes, for all measures	Yes, for some measures	Yes, for all measures		Yes, for all measures	
Regional marginal abatement cost (based on all sector resources)						
Some other approach				Uses a cost based on RGGI		

Note: Study Group participants in Connecticut, Massachusetts, and Rhode Island indicated they may be modifying their approach for non-embedded GHG costs in future years, pending advisement from policymakers.

Schedule MM-R1

Social cost of carbon (damage cost)

The SCC and other social costs of GHGs attempt to monetize the current and future damages resulting from emissions.[236] Policymakers can use these values to assess policies that address climate change. Developing a reasonable value for the SCC can be a complex endeavor. This section describes a brief history of the SCC as defined 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, adopting the values proposed by EPA in November 2022.

Recent history of the SCC in the United States

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 IWG considered a range of values varying 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, yielding an SCC value of $55 per short ton of CO_2 in 2021 (in 2024 dollars) and escalating over time. In 2017, the Trump Administration issued guidance to update the SCC estimate that only included domestic impacts of carbon emissions and recommended discount rates from 3 to 7 percent.

In early 2021, the Biden Administration rescinded the draft GHG guidance issued by the Trump Administration, adopting the Obama-era values as interim.[237] Biden re-convened the IWG and tasked the group with updating the SCC to reflect recommendations from the National Academies of Science, Engineering, and Medicine (National Academies).[238] The IWG published a Technical Support Document in February 2021 and a request for comments in the *Federal Register* in May 2021.[239,240] In September

236 For purposes of simplification, this text makes reference to "SCC" only, although social costs of other GHG emissions are estimated in AESC 2024 and may be applied analogously.

237 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.

238 Executive Order 13990. 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.

239 *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990*. Interagency Working Group on Social Cost of Greenhouse Gases, United States Government. February 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf?source=email.

240 Request for Comments: Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates, *Federal Register* Volume 86, Number 87 (Friday, May 7, 2021). Pages 24669-24670.

2022, Resources for the Future published a widely-cited journal article supporting a higher SCC.[241] In early October 2023, the U.S. Supreme Court declined to hear arguments challenging the Biden administration's use of interim formulas for estimating the social cost of GHGs, clearing the way for the IWG to promulgate a set of new costs.[242] Despite this, as of October 2023, the IWG has not published an updated estimate of the SCC.[243]

U.S. EPA's SCC recommendations

As the IWG's use of interim values was being challenged in federal court, EPA (a member of the IWG) proposed a set of SCC estimates in November 2022, consistent with the National Academies' recommendations.[244] EPA provided these estimates alongside a report describing the methodological updates implemented in its calculations. While previous federal estimates of the SCC relied on default assumptions from three integrated assessment models (IAMs), EPA's 2022 estimates rely on a detailed breakdown of the four modeling steps ("modules") required to estimate the SCC. EPA's approach is generally consistent with that used by Resources for the Future and that likely to have been adopted by the Federal IWG.[245] It represents the best state of the science and can be viewed as the authoritative federally derived calculation of the SCC, replacing that of the Federal IWG.[246]

The SCC calculation modules are socioeconomics and emissions, climate, damages, and discounting. EPA used the latest scientific literature and analysis to develop the modules and ensure that each component of the analysis is state-of-the-art in its respective discipline. The socioeconomics and emissions module results (based on projections from Resources for the Future) are input into the climate module to estimate emissions impacts such as temperature change and sea level rise. These impacts are then monetized in the damages module, which represents how willing people are to pay to avoid physical climate change impacts. The report averages results from three different damage functions—one at a subnational and sectoral scale, one at a country and sectoral scale, and one at a

[241] Rennert, K. et al. September 2022. "Comprehensive evidence implies a higher social cost of CO_2." *Nature*. Available at https://www.nature.com/articles/s41586-022-05224-9.

[242] See discussion of this action at https://www.eenews.net/articles/supreme-court-rejects-challenge-to-biden-climate-metric/, for example.

[243] Husselbee, A. and C. Jaschke. *Social cost of Greenhouse Gas Estimates*. October 2022. Available at https://eelp.law.harvard.edu/2022/10/social-cost-of-greenhouse-gas-estimates/.

[244] U.S. Environmental Protection Agency. September 2022. Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances. Values were originally reported in 2020 dollars per metric ton; here, they have been converted into 2024 dollars per short ton using AESC 2024's deflator. Available at https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf.

[245] Prest, B. C. et al. "Updated Estimates of the Social Cost of Greenhouse Gases for Usage in Regulatory Analysis." Resources for the Future. February 13, 2023. Available at https://www.rff.org/publications/testimony-and-public-comments/updated-estimates-of-the-social-cost-of-greenhouse-gases-for-usage-in-regulatory-analysis/.

[246] As of the time of this report's writing, we believe it is unlikely that the Federal IWG will release a separate update to the SCC. Instead, users of AESC should regard U.S. EPA's estimate of the SCC as being the most up-to-date estimate from the federal government. This version of the SCC can be applied in all of the same contexts that the previous IWG-estimated SCC could be applied in.

Schedule MM-R1

meta-analysis level. The discounting module takes the damages outputs and discounts them to the year of emissions.

Instead of selecting constant discount rates, EPA models dynamic discount rates to account for the relationship between economic growth and consumption. This dynamic framework gives greater weight to damages in a world with low economic growth compared to high economic growth. This is an improvement from previous federal SCC calculations, which only considered static discount rates. To reflect uncertainty in the starting rate, EPA provides outputs using near-term discount rates of 1.5 percent, 2 percent, and 2.5 percent. In general, these discount rates decline over time; as a result, these three specific discount rates (1.5 percent, 2 percent, and 2.5 percent) can be thought of as "starting" discount rates.

EPA recommends the inclusion of global effects, as air transport processes cause emissions to spread on a global scale and contribute to climate impacts around the world. The agency also recommends accounting for emissions besides CO_2, specifically CH_4 and N_2O, because reductions in CO_2 emissions could lead to increases in other GHG emissions. Finally, EPA notes that its assumptions are conservative (e.g., valuation of risk aversion, omitted climate change impacts) and likely underestimate damages.

Other SCC recommendations

EPA's SCC is one among many SCC calculations. Depending on the year described and discount rate used, SCCs in other studies range from roughly $60 to $924 per short ton of CO_2 (in 2024 dollars).[247,248,249,250] Generally speaking, experts examining or calculating an SCC typically recommend using reasonable, low discount rates (as will be discussed below); 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.

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). The NYS SCC Guideline uses the values issued by the Obama Administration in 2016, but with a different range of discount rates (1 percent, 2 percent, and 3 percent). Accordingly, the NYS SCC Guideline recommends an SCC of $131 per short ton of CO_2 in 2020 at a 2 percent discount rate (in 2024 dollars), escalating over time. On a 15-year

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[247] 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.

[248] 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.

[249] 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.

[250] 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.

Schedule MM-R1

levelized basis, this SCC is equal to $144 per short ton of CO_2. These SCC values are the same as those recommended in the 2021 AESC (albeit in 2021 dollars).[251,252] We note that in 2021, the Vermont Climate Council endorsed this version of the social cost of GHG emissions, using a 2 percent discount rate.[253]

Discount rates and the SCC

Discount rates reflect the degree to which future costs are discounted to present-day dollars. Generally speaking, higher discount rates imply a lower valuation of future costs or damages relative to today (a discount rate of 0 percent would imply equal valuation). In a seminal 2003 document on the topic of intergenerational discounting, the federal OMB stated that:

> Special ethical considerations arise when comparing benefits and costs across generations. Although most people demonstrate time preference in their own consumption behavior, it may not be appropriate for society to demonstrate a similar preference when deciding between the well-being of current and future generations. Future citizens who are affected by such choices cannot take part in making them, and today's society must act with some consideration of their interest.[254]

The original 2009-era SCC described a "central value," calculated using a discount rate of 3 percent. This discount rate was derived from a 2003-era methodology wherein the federal government compared the yield on 10-year Treasury notes with the annual change in consumer price index (CPI) on a 30-year basis.

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251 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/vocguid22.pdf.

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 2024 dollars per short ton using AESC 2024's deflator.

252 We also note that following the publication of the AESC 2021 study, the Massachusetts energy efficiency Program Administrators contracted with Synapse to update the 2021 AESC SCC recommendation in advance of their 2022–2024 Three-Year Energy Efficiency Plan. This supplemental study, published in October 2021, recommended an SCC equal to $443 per short ton (in 15-year levelized terms, in 2024 dollars) based on the IWG's Technical Support Document. This estimate considers updates to assumptions on climate science, economic damages, and socioeconomic and emission projections, and uses a 1 percent discount rate. Available at https://www.synapse-energy.com/sites/default/files/AESC_2021_Supplemental_Study-Update_to_Social%20Cost_of_Carbon_Recommendation.pdf.

253 See "Social Cost of Carbon and Cost of Carbon Model Review." Energy Futures Group. August 18, 2021. Available at https://aoa.vermont.gov/sites/aoa/files/Boards/VCC/SCC%20and%20Cost%20of%20Carbon%208-17-21.pdf and "Recommendations Regarding Social Cost of Carbon." Memo from Science & Data Subcommittee To: Vermont Climate Council. August 19, 2021. Available at https://aoa.vermont.gov/sites/aoa/files/Boards/VCC/SDSC%20SCC%20and%20CCR%20Recommendations_FINAL.pdf.

254 See Section 4 "Intergeneration Discounting" in OMB Circular A-4 (2003) at https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/.

Subtracting the 30-year average (from 1973 to 2002) of the CPI from the 30-year average of 10-year Treasury notes yielded a value of approximately 3 percent.[255]

In its latest projection of the SCC, EPA includes a robust discussion of discount rates.[256] First, EPA updates the formulation of discount rates originally performed in 2003, with some modifications. It provides two different values spanning two different time periods—one covering only the most recent 30 years (1991 to 2020), and one spanning the entire time series, inclusive of all of the years originally considered in the 2003 formulation through today (1973 to 2020). These two time periods are looked at for two reasons: first, the period covering nearer years is useful because it is more reflective of the low interest rate environment present since the early 1990s. The period covering the entire time period is useful because social discount rates should consider a long range of time. The discount rates derived for each of these two time periods are (when rounded) 1.5 percent for the more recent 30 years and 2 percent for the full 48-year time period.

Second, EPA considers additional information relevant to discount rates. It discusses discount rate formulations from the Social Security Administration's Trustees report, and three surveys of economists published in peer-reviewed economics journals on discount rates. In this literature review, EPA notes 2 percent as a commonly identified preferred social discount rate. EPA also derives 2.5 percent as a "high" end boundary of what is reasonable for social discount rates. EPA does not identify any of these as the "correct" social discount rate, instead saying:

> Therefore, considering the multiple lines of evidence on the appropriate certainty-equivalent near-term rate, the modeling results presented in this report [published by EPA] consider a range of near-term target rates of 1.5, 2.0, and 2.5 percent. This range of rates allows for a symmetric one point spread around 2.0 percent.[257]

After the publication of this EPA document, in November 2023 OMB finalized its recommendations for discount rates to be used in cost-effectiveness analysis across the federal government.[258] In this most recent analysis, OMB described a switch away from its previous methodology for counting discount rates to one that now utilizes 10-year Treasury Inflation-Protected Securities (TIPS) in place of a combination of 10-year Treasury yield data and inflation adjustors.[259] OMB's new method also makes an

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[255] Obama White House Archives. Last accessed September 4, 2023. "Circular A-4." Obamawhitehouse.org. Available at https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/.

[256] See https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf, pages 56-60.

[257] See https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf, page 59.

[258] *OMB Circular No. A-4. Explanation and Response to Public Input*. Office of Management and Budget. November 9, 2023. Available at https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4Explanation.pdf; *Circular No. A-4*. Office of Management and Budget. November 9, 2023. Available at https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf.

[259] OMB identifies that this new methodology is more accurate, as unlike the previous methodology, it does not combine two different sets of time series that span a backward-looking period (like the inflation adjustors) and a forward-looking period

Schedule MM-R1

adjustment for the use of different inflation indices. Under this new methodology, and using more recent data than in its previous publications, OMB identifies a discount rate of 2 percent. OMB also announced a plan to update this value with the latest data every three years.

It is possible that future disruptions caused by climate change could impact the decision-making related to discount rates. For example, economic disruptions related to climate change could cause real interest rates to increase or decrease. In addition, because the discount rate reflects the degree to which present generations value future damages, a future where climate change is causing obvious disruptions (economic or otherwise) is likely one where policymakers begin to value future damages more and more. Economic disruptions caused by climate change could also challenge the idea that future generations will be wealthier and thus able to address climate disruption; if future generations are less capable then it would be less appropriate to discount the costs they may face. In such a situation, a lower discount rate would likely be preferred. For example, in its November 2023 update to Circular A-4, OMB notes:

> Some believe that it is ethically impermissible to discount the utility of future generations. That is, government should treat all generations equally. Even under an approach that does not discount the utility of future generations, it is often appropriate to discount long-term consumption benefits and costs—although at a lower rate than the near-term effects more likely to fall on a single generation—if there is an expectation that future generations will be wealthier and thus will value a marginal dollar of benefits or costs by less than those alive today, or if there is a non-zero probability of sufficiently catastrophic risks. To account for these special ethical considerations, an extensive literature uses a "prescriptive" approach to long-term discounting, determining the appropriate degree of weight that society should place on the welfare of future generations.
>
> A distinct reason for discounting the benefits and costs accruing to future generations at a lower rate is uncertainty about the appropriate value of the discount rate. Private market rates provide a reasonably reliable reference for determining the rate at which society is willing to trade consumption over time within a few decades, but for extremely long time periods no comparable private rates exist. Because future changes in the social rate of time preference are uncertain but correlated over time, the certainty-equivalent discount rate will have a declining schedule. The appropriate discount rate declines because it is the average of the cumulative discount factors, not an average of the discount rates, that matters.[260]

We note that in a situation where policymakers treat all current and future generations equally, the appropriate discount rate would be zero. Mathematician Frank Ramsey argued that "while discounting made sense on behalf of an individual, it was ethically indefensible for society as a whole—the lives of

(like Treasury yields). This new methodology uses a dataset (TIPS) that was not available when OMB conducted its initial discount rate calculation in 2003.

[260] *Circular No. A-4*. Office of Management and Budget. November 9, 2023. Available at https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf. Page 80.

Schedule MM-R1

all generations should be treated equally."[261] When considering the purpose of climate-change-related projects in protecting the lives and mitigating the damages experienced by people living in future years, a zero discount rate may be the rate that is most in alignment with such goals. At this time, EPA has not released SCC estimates reflecting a zero-discount rate, and we are thus unable to provide such estimates.

Recommendation for AESC 2024

EPA's 2022 proposal is currently the most widely accepted SCC calculation in the United States. As a result, we recommend using the sets of SC-GHG projections it creates, across a subset of the discount rates it reports on. Table 94 and Table 95 present these recommended values, as well as the AESC 2021 recommendations for comparison. New in AESC 2024 is the inclusion of damage costs for three different GHGs (CO_2, CH_4, and N_2O), all of which can be used in cost-benefit analyses.

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 value between 1.5 percent and 2 percent, as this range reflects the range of discount rates within EPA's recommendation, including the latest recommendations from OMB and the majority of discount rate recommendations in the literature, as cited by EPA.[262] Other values described in the tables may be useful to examine in sensitivity testing of program or measure cost-effectiveness.

Policymakers may make different decisions about the appropriate discount rate for their state, depending on their state's policy context. For example, some policymakers may wish to adhere to the latest discount rate determination published by OMB (i.e., 2 percent). Other policymakers may identify a different policy driver in their state that suggests a lower discount rate (i.e., 1.5 percent)—perhaps because their states have more ambitious climate policies than other states or jurisdictions, thus suggesting that they discount the risk of future damages less than the average federal or state policymaker. As described above, policymakers recognizing the urgency of addressing climate change may wish to place a higher weight on intergeneration equity, and use a lower discount rate.

[261] Brumby, J. and M. Cloutier. "Using a zero-discount rate could help choose better projects and help get to net zero carbon.," *World Bank Blogs*, January 18, 2022, https://blogs.worldbank.org/governance/using-zero-discount-rate-could-help-choose-better-projects-and-help-get-net-zero-carbon.

[262] See https://www.epa.gov/system/files/documents/2022-11/epa_scghg_report_draft_0.pdf, page 59.

Schedule MM-R1

Table 94. Comparison of social costs of CO_2 at varying near-term discount rates from EPA's 2022 SCC Report and NYS SCC Guideline (2024 dollars per short ton)

	1.5%	2.0%	2.5%	AESC 2021, 2.0%
2024	$381	$222	$137	$138
2025	$385	$227	$139	$140
2026	$390	$230	$142	$141
2027	$396	$234	$145	$143
2028	$401	$239	$149	$145
2029	$406	$242	$151	$147
2030	$411	$246	$154	$148
2031	$416	$250	$157	$150
2032	$421	$254	$160	$152
2033	$426	$258	$164	$153
2034	$431	$262	$166	$156
2035	$436	$265	$169	$158
2036	$441	$270	$172	$160
2037	$446	$274	$175	$161
2038	$451	$277	$179	$163
2039	$456	$281	$182	$165
2040	$461	$286	$185	$167
2041	$466	$290	$188	$169
2042	$472	$294	$191	$171
2043	$477	$298	$195	$173
2044	$482	$303	$199	$175
2045	$488	$307	$202	$178
2046	$494	$311	$205	$179
2047	$500	$317	$209	$181
2048	$505	$321	$213	$183
2049	$510	$325	$216	$184
2050	$516	$329	$219	$186
15-year levelized	**$415**	**$249**	**$156**	**$144**

Sources and notes: Values for first three columns are obtained from https://github.com/USEPA/scghg/blob/main/EPA/output/scghg_annual.csv. AESC 2021 values are obtained from https://www.dec.ny.gov/docs/administration_pdf/vocfapp.pdf. All values have been converted into 2024 dollars per short tons. EPA value streams are shown from lowest to highest, left to right. All levelization calculations used each column's noted discount rate.

Schedule MM-R1

Table 95. Comparison of social costs of CH_4 and N_2O at varying near-term discount rates from EPA's 2022 SCC Report (2024 dollars per short ton)

	CH_4			N_2O		
	1.5%	2.0%	2.5%	1.5%	2.0%	2.5%
2024	$2,835	$2,086	$1,630	$100,149	$63,155	$41,743
2025	$2,928	$2,166	$1,701	$101,844	$64,466	$42,757
2026	$3,020	$2,247	$1,772	$103,541	$65,777	$43,771
2027	$3,113	$2,328	$1,844	$105,236	$67,088	$44,785
2028	$3,205	$2,409	$1,916	$106,931	$68,399	$45,799
2029	$3,298	$2,489	$1,986	$108,628	$69,710	$46,813
2030	$3,390	$2,570	$2,058	$110,323	$71,021	$47,827
2031	$3,498	$2,663	$2,141	$112,024	$72,358	$48,877
2032	$3,606	$2,758	$2,225	$113,724	$73,695	$49,926
2033	$3,713	$2,852	$2,307	$115,425	$75,033	$50,976
2034	$3,821	$2,946	$2,391	$117,124	$76,369	$52,025
2035	$3,929	$3,040	$2,474	$118,825	$77,706	$53,074
2036	$4,037	$3,133	$2,558	$120,525	$79,043	$54,124
2037	$4,145	$3,227	$2,640	$122,226	$80,380	$55,172
2038	$4,252	$3,321	$2,723	$123,925	$81,717	$56,221
2039	$4,360	$3,415	$2,807	$125,626	$83,054	$57,271
2040	$4,468	$3,509	$2,890	$127,326	$84,391	$58,320
2041	$4,584	$3,610	$2,980	$129,227	$85,899	$59,508
2042	$4,700	$3,713	$3,071	$131,128	$87,408	$60,698
2043	$4,816	$3,814	$3,161	$133,027	$88,916	$61,886
2044	$4,931	$3,916	$3,252	$134,928	$90,425	$63,075
2045	$5,047	$4,018	$3,342	$136,829	$91,933	$64,264
2046	$5,163	$4,119	$3,433	$138,730	$93,442	$65,453
2047	$5,279	$4,221	$3,522	$140,630	$94,950	$66,642
2048	$5,394	$4,323	$3,613	$142,530	$96,459	$67,830
2049	$5,510	$4,424	$3,703	$144,431	$97,968	$69,019
2050	$5,627	$4,526	$3,794	$146,331	$99,476	$70,208
15-year levelized	**$3,491**	**$2,650**	**$2,122**	**$111,558**	**$71,905**	**$48,450**

Sources and notes: Values are obtained from https://github.com/USEPA/scghg/blob/main/EPA/output/scghg_annual.csv. All values have been converted into 2024 dollars per short tons. EPA value streams are shown from lowest to highest, left to right. All levelization calculations used 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.[263]

[263] We note that a third approach to estimating costs of carbon also exists: a willingness-to-pay approach. Under such an approach, consumers are surveyed to estimate the amount of money a household would be willing to pay to abate one ton of carbon. AESC does not include any recommendations related to willingness-to-pay-derived carbon costs for two reasons. First, a marginal abatement cost can be construed as a willingness-to-pay cost, assuming that consumers have effectively delegated their decision-making on this topic to policymakers who have identified that some level (and cost) of technology investment is needed to abate large quantities of carbon. Second, the AESC authors do not view the willingness-to-pay approach as a viable lens with which to price carbon from a state policymaking perspective. Estimates derived using a willingness-to-pay approach are by definition aggregations of estimates by single individuals. These individuals are likely to have less insight into the damages incurred by climate change or the costs needed to abate carbon. They are also likely to

The marginal abatement technologies examined in AESC focus on the technologies likely to be deployed in New England in the near future. As a result, AESC 2024 does not include an analysis of other technologies that may be deployed elsewhere to abate carbon emissions.[264] Within those technologies likely to be deployed in New England, AESC 2024 proposes two different local marginal abatement costs for New England states with different policy contexts.

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 both AESC 2018 and AESC 2021, 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 with the construction of new resources (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 they 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 considered for analysis. This temporal aspect complicates each of the factors described above.

Given that AESC 2024 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

approach this question from an individually focused perspective over the near term (i.e., they are unlikely to base their estimates on costs incurred to people around the globe, over a span of decades). As a result, willingness-to-pay costs are unlikely to represent a comprehensive estimate of the costs associated with incurring or avoiding climate change.

[264] This includes carbon capture and sequestration technologies, a technology examined in AESC 2021.

Schedule MM-R1

half of the overall emissions reduction potential for Massachusetts.[265] Furthermore, if this same study were performed absent the resources being tested for cost-effectiveness with AESC 2024 (e.g., future energy efficiency or electrification), we would likely find offshore wind to be the marginal resource.[266] Because of offshore wind's large resource potential, it is likely to be the marginal resource in any number of scenarios that test the sensitivity of marginality to variables like prices, reduction potentials, states considered to have "required" emission reductions, and year being considered for marginality. Finally, we observe that in our own analysis of counterfactuals, counterfactuals with more load tend to see more offshore wind built (and less onshore wind or solar) in response to renewable portfolio standard requirements. This suggests that offshore wind is routinely the marginal resource for clean energy.[267,268]

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 2024 study period. In August 2022, NREL published its *2022 Offshore Wind Market Report*.[269] 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 also accounted for differences in contract length by converting the annual strike

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[265] 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.

[266] Other information may be available from forthcoming inputs related to renewable resource builds.

[267] Similar findings are present in a 2023 Form Energy study of multi-day storage in New England. See Wilson, R. et al. "The value of multi-day energy storage in New England." Form Energy. September 28, 2023. Available at https://formenergy.com/insights/the-value-of-multi-day-energy-storage-in-new-england/.

[268] Study Group members raised the question of whether the marginal resource for greenhouse gas emissions should include both offshore wind and long-duration storage. In order to answer this question, we reviewed resources built in this project's EnCompass modeling in years with high renewable penetration. We find that in all six of the main counterfactuals, there are about 15 GW of offshore wind built by 2040, but few MW of long-duration storage built by this year. Past 2040, comparisons between Counterfactual #1 and Counterfactual #2 (two scenarios without building electrification measures) reveal higher quantities of OSW added in Counterfactual #1 (the case with no programmatic energy efficiency and therefore higher load). However, we observe essentially no net additions of battery storage between these counterfactuals. This implies that OSW alone should remain the MAC through 2050. The results of comparisons between scenarios with building electrification are more complex. First, when we compare Counterfactual #2 and Counterfactual #3 (two cases that differ both in terms of energy efficiency and building electrification) and Counterfactual #5 and Sensitivity #2 (two cases that differ in terms of renewable energy requirements, but have identical load projections, including the inclusion of programmatic building electrification), we observe that incremental offshore wind is added alongside storage resources on a roughly 1:1 ratio. However, it is unclear whether this is finding is useful for information the marginal abatement cost for building electrification measures. Because these measures concern switching between multiple fuels (e.g., direct gas or fuel oil use and electricity), it seems likely that the relevant marginal abatement cost is the one described in the "Derived from multiple sectors" section of this chapter, not the one based on the electric sector alone.

[269] NREL (National Renewable Energy Laboratory). 2022. *Offshore Wind Market Report: 2022 Edition.* Available at https://www.energy.gov/sites/default/files/2022-09/offshore-wind-market-report-2022-v2.pdf.

price to a present value. Since this report contains strike price data for projects with estimated online dates between 2020 and 2028, we use the average cost in each year to develop our price forecast.

To project how the cost of offshore wind could change after 2028, we referenced NREL's most recent ATB study.[270] NREL releases a new version of the ATB each year as a way to track how improvements in research and development, 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 generally decreasing trend in offshore wind's levelized cost of energy over time, largely due to increasing turbine sizes and increased efficiency in the supply chain. The compound average cost decline from 2028 to 2050 was used in conjunction with the average strike price in 2028 to develop a forward-looking trend out through 2050.[271] Figure 51 shows the offshore wind price trajectory we use to calculate the marginal abatement cost over the AESC 2024 study period. Recently, economic uncertainty and supply chain issues have pushed projections of offshore wind costs higher (in spite of newly renewed federal tax credits). In some cases, this uncertainty has caused wind developers and utilities to terminate their power purchase agreements.[272] NREL's *Offshore Wind Market Report* includes a strike price for Mayflower Wind (renamed SouthCoast Wind), which we exclude from our analysis due to delays and uncertainty in the status of its power purchase agreement.[273] This cost is $117 in AESC 2024 (levelized on a 15-year basis using a 1.74 percent discount rate).[274] In AESC 2021, this cost was $100 (levelized on a 15-year basis using a 0.81 percent discount rate, adjusted to 2024 dollars).

[270] NREL (National Renewable Energy Laboratory). 2023. "2023 Annual Technology Baseline." Available at: https://atb.nrel.gov/electricity/2023/data. .

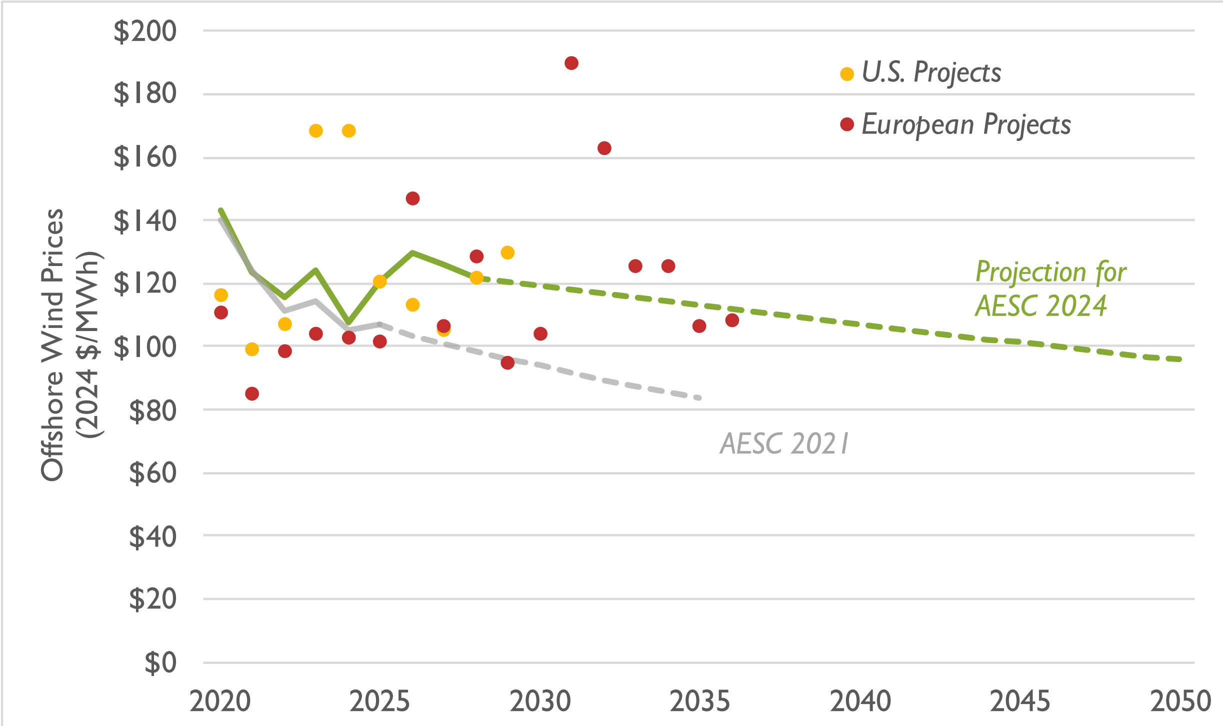
[271] We referenced the levelized cost of energy trajectory that assumed the "Market + Policies" financial case, a moderate technology innovation scenario, and the default technology class. The Market + Policies case considers federal tax credits and debt interest rates. Class 3 was selected as the default 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/2023/offshore_wind for more detail.

[272] Wolfe, S. July 21, 2023. "Rough seas ahead as multiple offshore wind power purchase agreements are scrapped." *Renewable Energy World*. Available at: https://www.renewableenergyworld.com/wind-power/offshore/rough-seas-ahead-as-multiple-offshore-wind-power-purchase-agreements-are-scrapped/#gref.

[273] None of the other wind farms affected by the above-mentioned power purchase agreement issues were included in the NREL strike prices.

[274] As elsewhere assumed in AESC 2024, the cost of offshore wind assumes that this resource can take advantage of investment tax credits throughout the study period.

Figure 51. Price trajectory for offshore wind



Sources: Data from NREL, "Offshore Wind Market Report: 2022 Edition" and 2023 Annual Technology Baseline. Datapoint for Mayflower Wind removed due to uncertainty about the future of the current agreement.

After developing the cost trajectory using the methodology described above, we subtract the estimated energy costs from the total offshore wind price.[275] Because the amount paid for energy represents revenue to the offshore wind project owner, only the remainder is considered the abatement cost.[276] This abatement cost represents the incremental cost of this non-emitting technology. After levelizing the abatement cost stream into a present value, we multiply the cost by the annual marginal emissions rates described in Table 97. The final value translates to a cost per avoided short ton of CO_2 of $185 per short ton.

In AESC 2021, the cost of avoided CO_2 was reported to be $125 per short ton in 2021 dollars or $141 per short ton in 2024 dollars. We find that the AESC 2024 cost is 31 percent higher, primarily due to an increase in the projected cost of offshore wind as a resource, relative to the projection developed in AESC 2021.

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[275] For the calculations described in this paragraph, we have subtracted the energy costs associated with Counterfactual #1.

[276] 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.

Schedule MM-R1

Derived from multiple sectors

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.[277]

One such technology is RNG.[278] RNG is a term for natural gas derived from biomass or other renewable resources and is fully interchangeable with conventional natural gas. Section 2.3: *New England natural gas market* contains a price projection for RNG, along with information about the methodology used to make that projection (see Table 20 in that section). Depending on the feedstock considered, RNG price projections range from $23 to $61 per MMBtu during the AESC 2024 study period. Assuming the marginal type of RNG (synthetic natural gas, or SNG) completely replaces the consumption of natural gas, this translates into a cost of $581 per short ton.

This value can be compared to a value of $557 per short ton (in 2024 dollars) from AESC 2021. The projected value in AESC 2024 is lower due to (a) different considerations of RNG feedstock and (b) updated information on costs and potentials of RNG feedstock.

This cost assumes 100 percent of natural gas is avoided through the use of RNG. The emission reduction requirements in a given state may not be this stringent, leading to an abatement cost that is different than the one stated above. For one example of how this abatement cost could be applied with this modification, see the methodology described for Massachusetts' emission sublimits described in Section 4.8: *Embedded emissions regulations*.

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[277] 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.

[278] 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.

Schedule MM-R1

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, abatement cost modeling requires numerous assumptions on available technologies, costs, potentials, emissions reduction targets, and timescales.

8.2. Applying non-embedded costs

Non-embedded costs can be applied to both the electric sector and non-electric sectors; in other words, the approaches described in this chapter estimate avoided non-embedded GHG costs, but they are not specific to a measure type. In fact, one should use a consistent approach for non-embedded GHG avoided costs for all measures being analyzed. In the AES 2024 User Interface, the avoided GHG costs are available in both $ per kWh and $ per MMBtu for application to all measure types.

The following sections describe each approach.

Electric sector

AESC 2024 embeds four electric-sector regulations in New England in its forecast of avoided energy costs: two (RGGI and section 111 of the *Clean Air Act*) are 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.[279] In AESC 2024, we sum these embedded costs (all four for Massachusetts, and RGGI for the other five states), then subtract the annual values from the relevant marginal abatement cost (see Table 96). The impacts of new, proposed regulations under Section 111 of the *Clean Air Act* are treated differently than the other embedded costs. The proposed regulations under Section 111 modifies how certain power plants are allowed to dispatch (and therefore modifies the dispatch for the entire fleet of power plants) but does not include the purchase of certificates or credits to achieve compliance. As a result, there is no meaningful way to determine the cost of Section 111, as it impacts demand-side measures. In other words, the implementation of a demand-side measure does not impact how a power plant owner complies with

[279] We note that by convention, costs associated with other renewable portfolio standards and RPS-like programs are not treated as embedded GHG costs. This is because these programs may have been proposed or are currently being performed for a variety of reasons, including industry development, public health improvements, job development, price hedging, as well as GHG abatement. Massachusetts' 310 CMR 7.75 (the two "Clean Energy Standard" programs), are the sole exception to this, as they were promulgated with the express purpose of reducing GHG emissions. This convention may lead to some overcounting, as the costs of many of these RPS-like programs may have a component that is linked with GHG reductions. However, in practice, it is impractical to derive how much of this component is linked with GHG abatement, resulting in the treatment described here.

Schedule MM-R1

Section 111, in the same way that the implementation of a demand-side measure could decrease or increase the number of RGGI credits or MA Clean Energy Standard certificates purchased.

Table 96. 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. We can compare this to 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. The denominator of this emissions rate includes generation from many resources (e.g., nuclear, hydro) that do not economically respond to changes in demand.

Because Section 111 changes the dispatch of power plants, we assume that the effects of this regulation are embedded in the marginal emission rate (which is presumably lower than it would be without the effects of this regulation), thereby impacting (and likely decreasing) the avoided costs of demand-side measures.

Modeled, regionwide marginal emission rates

Within the concept of marginal emission rates, there are both "short-run" and "long-run" emission rates, each of which has separate implications for the resulting dollar-per-MWh values.[280] Short-run and long-run marginal costs are both applicable 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). Generally speaking, "short-run" marginal emission rates are those experienced over the near term (e.g., over a year), where the resource mix of the grid is held fixed, without any retirements or additions. In contrast, "long-run" marginal emission rates are those experienced over a period longer than a year, where the grid experiences resources and additions. It is common for long-run marginal emission rates to be lower than short-run marginal emission rates, especially when modeling regions that are trending towards less fossil generation (i.e., coal and gas plants are retiring, and wind and solar resources are being added).

[280] AESC 2021 utilized different definitions of "long-run" and "short-run" marginal emission rates. We have modified the nomenclature in AESC 2024 to be more consistent with the wider literature. Most importantly, the section formerly titled "long-run marginal emission rates" in AESC 2021 is now titled "State policy considerations for marginal emission rates."

Schedule MM-R1

Using EnCompass, we calculate regionwide marginal CO_2 emission rates by making comparisons between counterfactuals.[281] Specifically, we calculate the change in emissions in each year for the entire New England region and divide that number by the change in demand for the entire New England region, for six sets of counterfactual pairings.[282] We perform this action for three reasons. First, many counterfactual pairings exhibit similar load levels, especially in the early years of the analysis. Small differences in load are generally not sufficient to produce meaningful marginal emission rates. Second, often comparisons between counterfactuals that exhibit many differences (e.g., not just higher or lower load and more or fewer renewables, but different load shapes, different load changes in different regions, and different quantities of exogenous active demand management measures) may produce anomalous, noisy, or difficult-to-interpret results for marginal emission rates. Third, because of those differences, these scenarios may feature slightly different year-on-year deployment schedules for new power plants (including non-emitting energy resources). When these deployment schedules differ, especially in early years when load differences are small, marginal emission rates may be erratic and not meaningful.

Thus, Synapse calculates a generalized marginal emission rate by averaging the marginal emissions rates for each counterfactual "pairing", and then combining them to form a single set of hourly marginal emission rates, with each hour's marginal emission rate weighted by each of the six counterfactual pairings' changes in demand. We then aggregate this emissions rate over multiple hours to provide a set of summarized marginal emissions rates, and finally we average them on a three-year repeating basis to provide a smoothing effect to counteract the impact that small year-on-year differences in clean energy deployment have on the marginal emission rate (see Table 97).

AESC 2024's EnCompass modeling produces long-run marginal regionwide emission rates. They are the emission rates observed over the entire New England region, over a 27-year period, as grid-level resources are added and removed. In AESC 2021, we observed that the state policies to procure specific types of clean energy (e.g., offshore wind, Canadian hydropower, distributed solar) added up to a quantity of GWh that exceeded the sum of the REC requirements in the six states. This meant that changing the level of load would *not* modify the amount of RECs sold or renewable facilities built. As a result, this led to relatively flat CO_2 emission rates over time.

Compared to AESC 2021, the counterfactuals in AESC 2024 features different load levels, different renewable requirements, and a longer study period. We observe a marginal emission rate that

[281] 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. It is also the same approach used by NREL in its Cambium scenarios viewer. Gagnon, Pieter; Cowiestoll, Brady; Schwarz, Marty (2023): Cambium 2022 Data. National Renewable Energy Laboratory. https://scenarioviewer.nrel.gov.

[282] Counterfactual "pairings" are between the following counterfactuals: Counterfactual 1, Counterfactual 2, Counterfactual 3, and Counterfactual 5. We chose these counterfactuals because they represent the range of different load growth projections, with each of the four cases including both, none, or one of each of the following load components: energy efficiency and building electrification. There are six possible comparisons between these four counterfactuals.

Schedule MM-R1

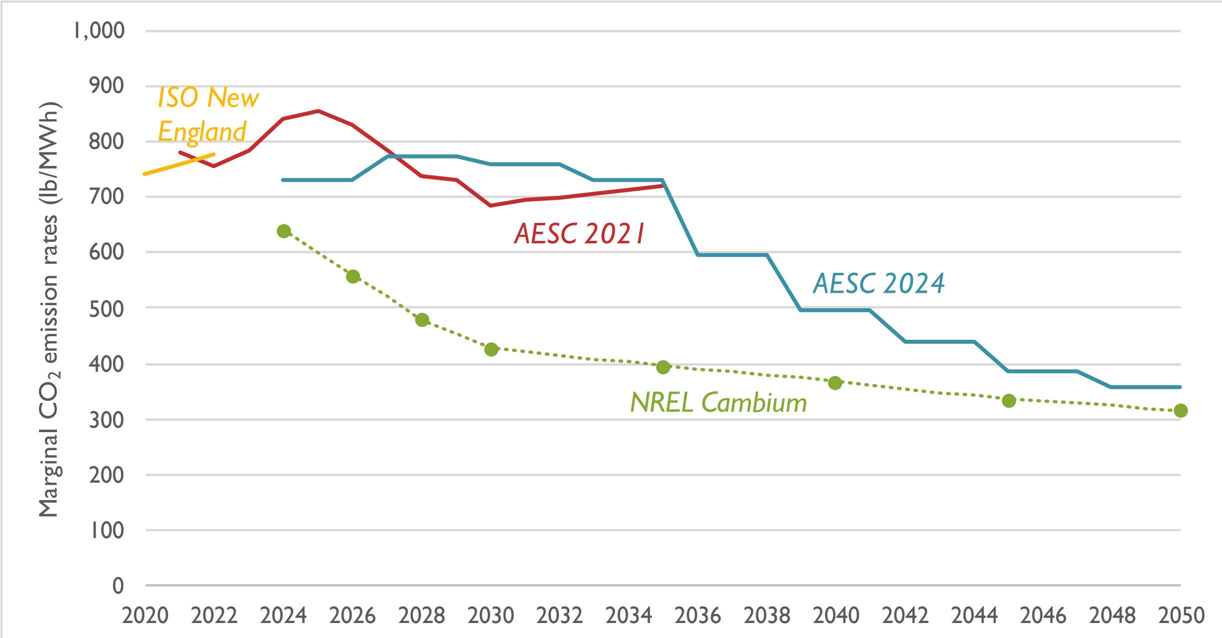
resembles a gas plant in the near term (e.g., through the early 2030s), with some variation due to lumpiness in clean energy deployment. Over time, clean energy tends to make up a larger and larger share of the differences in load, leading to a steadily decreasing marginal emission rate.

We observe that the 2024 marginal emission rate calculated in AESC 2024 resembles short-run marginal emission rates for New England, such as those calculated by ISO New England in its annual air emissions report, and those published by EPA as part of its AVERT model.[283] Over the medium and long terms, AESC 2024 marginal emission rates are comparable to those calculated in AESC 2021, and higher than those calculated in NREL's Cambium 2022 viewer, for New England.[284] This is primarily due to differences in terms of clean energy additions and differences in load assumptions. Both AESC 2021 and Cambium 2022 have more clean energy making up a greater share of load than is assumed in AESC 2024. See Figure 52 for a comparison of marginal emission rates.

[283] *2022 ISO New England Electric Generator Air Emissions Report*. ISO New England. December 2023. Available at https://www.iso-ne.com/static-assets/documents/100006/final_2022_air_emissions_report_appendix.xlsx. Table 3-11.; *Avoided Emission Rates Generated from AVERT, AVERT v4.1*. U.S. EPA. Accessed December 2023. Available at https://www.epa.gov/avert/avoided-emission-rates-generated-avert.

[284] Gagnon, Pieter; Cowiestoll, Brady; Schwarz, Marty (2023): Cambium 2022 Data. National Renewable Energy Laboratory. https://scenarioviewer.nrel.gov.

Figure 52. Comparison of marginal emission rates



Notes: ISO New England data is obtained from the 2022 Air Emissions Report*; NREL Cambium data is obtained from the 2022 MidCase for New England. NREL Cambium data is provided for 2024, 2026, 2028, 2030, 2035, 2040, 2045, and 2050. All other data points shown in this figure are interpolated.*

The emission rates shown in Table 97 are for CO_2 emitted from combustion only. New in AESC 2024, we also estimate which resources contribute to marginality. This allows us to derive information about how much fuel is reduced from certain generation types and then to apply emission factors related to other GHGs as well as upstream emissions. Table 98 shows the marginal combustion and upstream emission rates for all modeled GHGs (for the summer on-peak period only), using the values described in *Appendix G: Marginal Emission Rates* . For reference, Table 99 includes average emission rates for Counterfactual #1, although we note that these should generally not be applied to DERs for the purpose of cost-benefit testing. Additional information on emission rates, including data through 2050, is available in the AESC 2024 User Interface.

Table 97. Modeled marginal electric sector CO_2 emissions rates (lb per MWh), point of combustion

	Annual Average	Winter		Summer	
		On Peak	*Off Peak*	*On Peak*	*Off Peak*
2024	732	917	758	643	436
2025	732	917	758	643	436
2026	732	917	758	643	436
2027	775	852	813	709	622
2028	775	852	813	709	622
2029	775	852	813	709	622
2030	760	781	722	763	797
2031	760	781	722	763	797
2032	760	781	722	763	797
2033	730	737	650	804	812
2034	730	737	650	804	812
2035	730	737	650	804	812
2036	595	615	537	637	637
2037	595	615	537	637	637
2038	595	615	537	637	637
2039	495	508	449	547	519
2040	495	508	449	547	519
2041	495	508	449	547	519
2042	441	463	399	488	444
2043	441	463	399	488	444
2044	441	463	399	488	444
2045	387	390	374	409	390
2046	387	390	374	409	390
2047	387	390	374	409	390
2048	357	383	343	352	343
2049	357	383	343	352	343
2050	357	383	343	352	343

Notes: We assume all counterfactuals utilize the same set of marginal emission rates.

Table 98. Modeled marginal electric sector greenhouse gas emissions rates (lb per MWh)

	Combustion			Upstream		
	CO2	*CH4*	*N2O*	*CO2*	*CH4*	*N2O*
2024	732	0.014	0.001	165	4.742	0.002
2025	732	0.014	0.001	165	4.742	0.002
2026	732	0.014	0.001	165	4.742	0.002
2027	775	0.014	0.001	175	5.021	0.002
2028	775	0.014	0.001	175	5.021	0.002
2029	775	0.014	0.001	175	5.021	0.002
2030	760	0.014	0.001	172	4.928	0.002
2031	760	0.014	0.001	172	4.928	0.002
2032	760	0.014	0.001	172	4.928	0.002
2033	730	0.014	0.001	165	4.731	0.002
2034	730	0.014	0.001	165	4.731	0.002
2035	730	0.014	0.001	165	4.731	0.002
2036	595	0.011	0.001	135	3.857	0.002
2037	595	0.011	0.001	135	3.857	0.002
2038	595	0.011	0.001	135	3.857	0.002
2039	495	0.009	0.001	112	3.214	0.001

Schedule MM-R1

	Combustion			Upstream		
	CO2	*CH4*	*N2O*	*CO2*	*CH4*	*N2O*
2040	495	0.009	0.001	112	3.214	0.001
2041	495	0.009	0.001	112	3.214	0.001
2042	441	0.008	0.001	100	2.865	0.001
2043	441	0.008	0.001	100	2.865	0.001
2044	441	0.008	0.001	100	2.865	0.001
2045	387	0.007	0.001	88	2.536	0.001
2046	387	0.007	0.001	88	2.536	0.001
2047	387	0.007	0.001	88	2.536	0.001
2048	357	0.007	0.001	82	2.338	0.001
2049	357	0.007	0.001	82	2.338	0.001
2050	357	0.007	0.001	82	2.338	0.001

Notes: We assume all counterfactuals utilize the same set of marginal emission rates. Values are shown for All Hours only; values for all time periods are available in the AESC 2024 User Interface.

Table 99. Modeled average electric sector CO_2 emissions rates (lb per MWh), point of combustion, Counterfactual #1

	Annual Average
2024	342
2025	342
2026	342
2027	255
2028	255
2029	255
2030	176
2031	176
2032	176
2033	155
2034	155
2035	155
2036	156
2037	156
2038	156
2039	158
2040	158
2041	158
2042	163
2043	163
2044	163
2045	162
2046	162
2047	162
2048	159
2049	159
2050	159

Using the same methodology used for marginal emission rates, we can also estimate marginal heat rates. Table 100 displays the regionwide heat rates for each modeled period.

Schedule MM-R1

Table 100. Modeled marginal electric sector heat rates (MMBtu per MWh)

	Annual Marginal
2024	6.14
2025	6.14
2026	6.14
2027	6.51
2028	6.51
2029	6.51
2030	6.39
2031	6.39
2032	6.39
2033	6.13
2034	6.13
2035	6.13
2036	5.00
2037	5.00
2038	5.00
2039	4.16
2040	4.16
2041	4.16
2042	3.71
2043	3.71
2044	3.71
2045	3.27
2046	3.27
2047	3.27
2048	3.01
2049	3.01
2050	3.01

State policy considerations for marginal emission rates

Some states may have policy directives that require them to consider additional steps to estimate marginal emission rates. The following paragraphs provide guidance on one methodology that AESC users can apply to adjust their marginal emission rates.[285] As of the writing of this report, it is the understanding of the AESC authors that this additional step is currently in partial use in Vermont but is not in use in any of the other five New England states.

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,

[285] 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.

Schedule MM-R1

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.[286] Because the renewables driven by these RPS policies would also displace marginal generators and decrease emissions, ignoring the effects of these policies would overestimate the emissions-reducing impacts of energy efficiency and other DSM resources.

For time periods of one year or more, we derive the marginal emissions rate from not only the marginal displaced resource, but also from 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.[287] As a result, this 1 MWh would avoid 0.5 MWh associated with the marginal emissions rate described in Table 97, 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.[288]

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.

- 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

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286 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.

287 This simplified example does not consider impacts of T&D losses.

288 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.

Schedule MM-R1

(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 are 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 a Class-1 RPS compliance surplus in each state, in each counterfactual, and in each study year through 2037. 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

Schedule MM-R1

required. In the middle years of the study period, regional REC surpluses of thousands of 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.[289]

Non-electric sectors

For non-electric sectors, we multiply the dollar-per-ton non-embedded value 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 *Appendix G: Marginal Emission Rates* for more information on non-electric emission rates). Because policies such as RGGI only impact the electric sector, they should not be taken into account when calculating non-electric sector impacts (i.e., they are not embedded). Otherwise, the same SCC or marginal abatement costs described above can be applied to emissions projected from these non-electric sectors.

In general, AESC users should use a consistent approach for estimating non-embedded GHG avoided costs for all measures being analyzed. For example, users should not apply a social cost of GHGs to some measures in a portfolio (or just the electric savings associated with a measure) and a marginal abatement cost to other measures (or the associated gas savings associated with an electric measure).

[289] 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.

Schedule MM-R1

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 a given counterfactual—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.

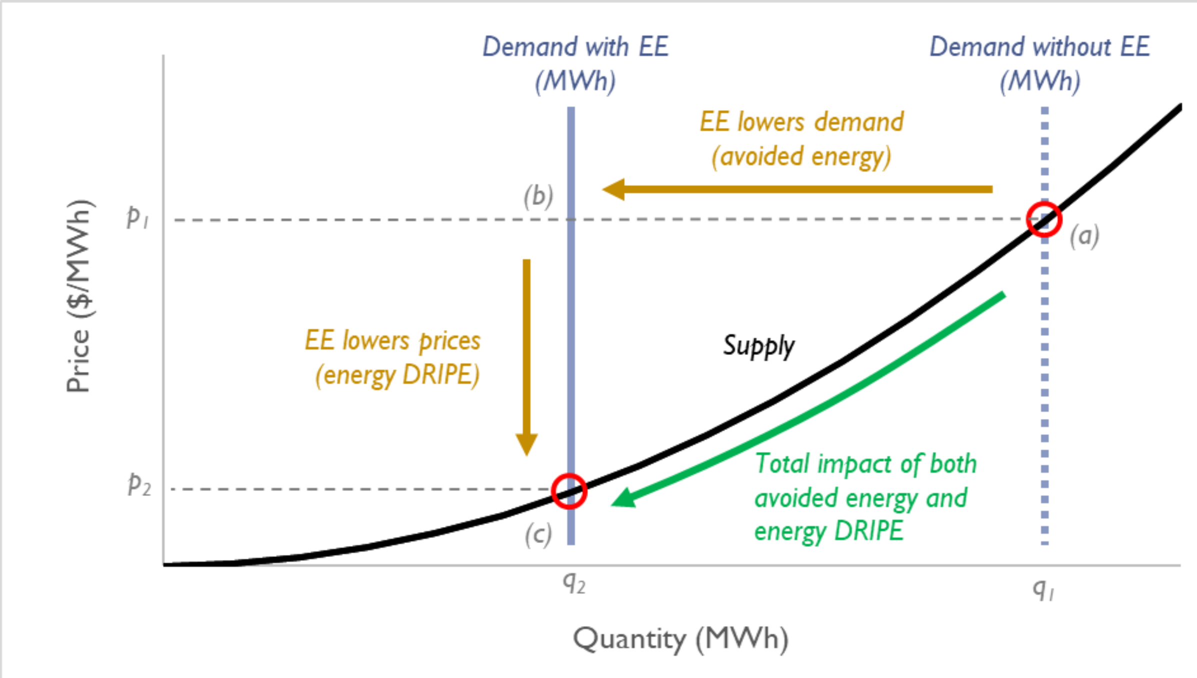
Generally speaking, compared to AESC 2021, we find (a) similar energy DRIPE values due to a number of factors (including changes in energy prices, changes in load, and changes in hedging assumptions) that largely offset one another, (b) similar trends capacity DRIPE values (although these values tend to be highly variable year-to-year in both AESC 2024 and AESC 2021), (c) lower gas supply and electric-to-gas DRIPE values due to decreases in price shifts, (d) higher gas-to-electric cross-DRIPE values due to increases in price shifts, and (e) higher 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 2021 and AESC 2024.

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 53 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 53, 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 x q_1, while the total cost at point (c) is equal to p_2 x q_2. If DRIPE were uncounted, the total cost would incompletely be calculated as the cost at point (b), or p_1 x q_2.

Schedule MM-R1

Figure 53. 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 (energy efficiency 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.

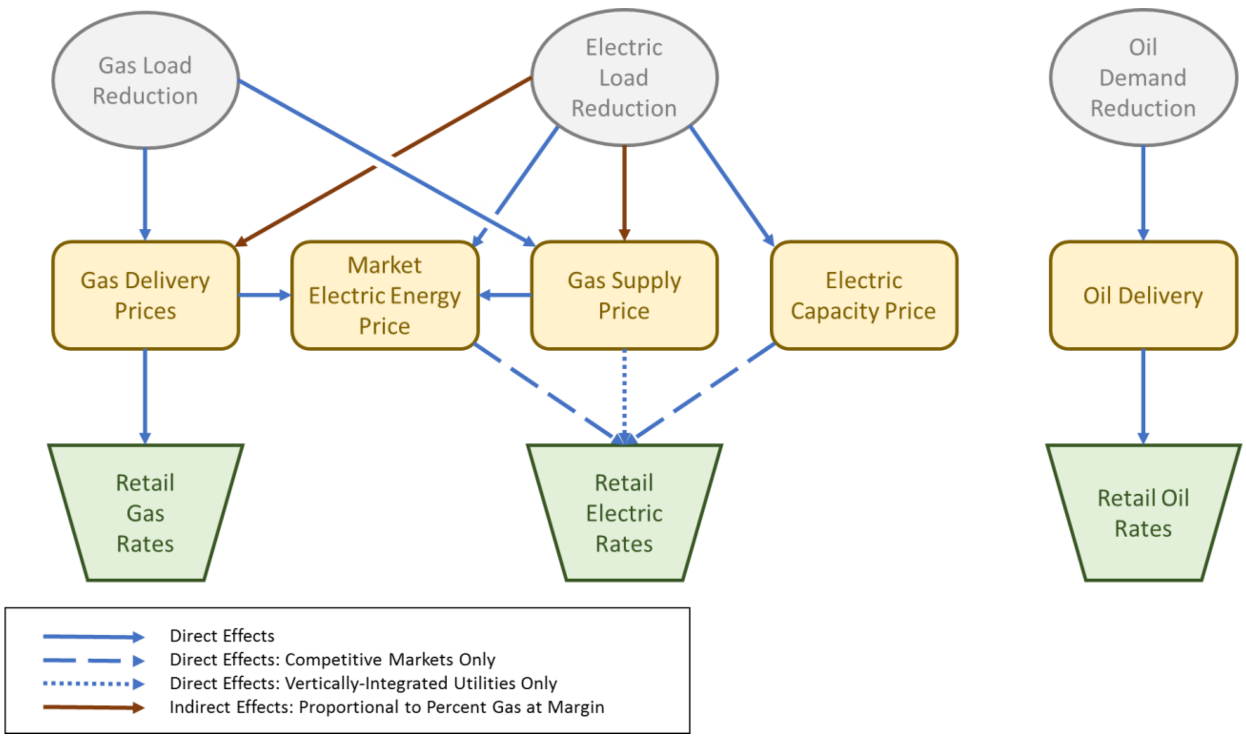
Schedule MM-R1

- **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 54.

Figure 54. 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.

Schedule MM-R1

General DRIPE methodology

In AESC, we estimate DRIPE according to the following steps:

1. First, we calculate a "price shift." 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, we multiply these price shifts by total future market demand, so that we may then apply them 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.[290]

3. Finally, we adjust the price-per-demand value. 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 (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"). We calculate Intra-zonal DRIPE 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.[291]

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

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[290] 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.

[291] An equivalent mathematical operation would be to multiply the price shift by the regional total demand less the demand for the state in question.

Schedule MM-R1

they are not counted in a measure's cost-effectiveness test. We also note that no other states would count these benefits.

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 2024 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 2021. Generally speaking, we conduct a set of regressions of historical zonal hourly market prices against zonal and regional load to develop elasticities. Then, we estimate the timing and duration of benefits based upon the following market realities:

1. We assume the reductions in wholesale prices 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.[292]
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 2024, as with AESC 2021, 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 there is an underlying relationship between prices and loads which can be

[292] 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 unit 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).

Schedule MM-R1

Nuclear output is steady 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.[293] As a result, we remove the MWh contribution of these non-price-responsive generators from our "ISO Demand" variable.

In AESC 2024, we use data from January 2018 through December 2022 as the basis for our regressions.[294] Figure 55 plots actual price and demand data (in blue) against predicted data (in red) estimated using Equation 4 for one illustrative region and period. We perform a similar regression 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).[295]

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[293] 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 similar whether gross net load is used in Equation 4, reducing the usefulness of additional complexity.

[294] This time period spans over 43,800 datapoints (for each of the nine modeled regions), which provides our regressions with sufficient detail to accurately predict the relationship between prices and loads. Previous AESC studies utilized shorter time periods; AESC 2024 broadens the time period examined in an attempt to include years both before and after the impacts of the COVID-19 pandemic and subsequent impacts on commodities markets. Hourly energy price data and gross load data was obtained from ISO New England (for example, see ISO New England. 2022. *ISO New England Public*. Available at https://www.iso-ne.com/static-assets/documents/2022/02/2022_smd_hourly.xlsx).

Sub hourly data on ISO New England's fuel mix was downloaded from ISO New England then averaged to produce hourly results for wind, solar, and nuclear generation. ISO New England. Last accessed September 30, 2023. "Dispatch Fuel Mix." *ISO-NE.com*. Available at https://www.iso-ne.com/isoexpress/web/reports/operations/-/tree/gen-fuel-mix

Daily data on delivered prices to Algonquin Citygate were obtained from Natural Gas Intelligence's (NGI's) "Daily" subscription service. NYMEX Futures prices for Henry Hub were retrieved from NGI's "Forward Look" subscription service. More details on each service can be found at: https://www.naturalgasintel.com/.

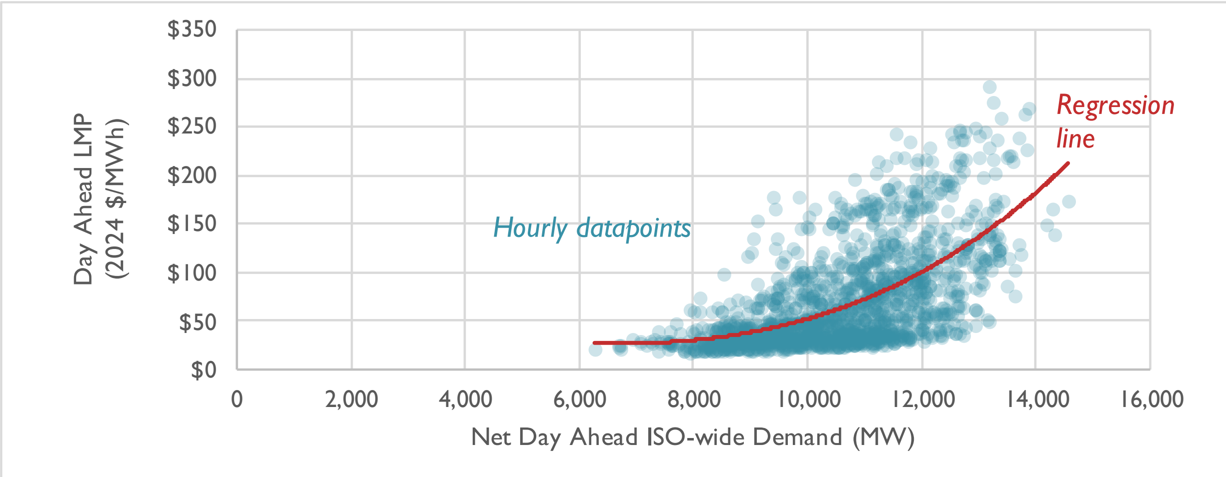
For points with very low zonal LMPs, elasticities are very large. This is a byproduct of the modeling and elasticity calculation, not of any structural phenomenon. When LMPs are $0/MWh, the elasticity is infinite. We exclude calculated point elasticities when zonal prices are less than $5/MWh. These exclusions occur very rarely—for the ISO New England region, for example, there is one such hour.

[295] We use a similar approach 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.

Schedule MM-R1

In general, the model produces a good fit (R^2 above 0.7) for 100 percent of the 216 regressions (24 periods X 9 regions). Periods with relatively lower R^2 values tend to be those in shoulder months (spring and fall) or off-peak periods.

Figure 55. Illustrative regression for WCMA, February 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 in which we used different natural gas prices for each point. Final DRIPE calculations use monthly timeframes instead of quarterly; different zones have different price/load pairs.

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

$$Elasticity = \frac{\%\ change\ in\ price}{\%\ change\ in\ demand} = \frac{Instantaneous\ slope\ of\ price\ relative\ to\ demand}{Hourly\ electricity\ price} \times Hourly\ demand$$

We then aggregated each of the resulting elasticities into a single load-weighted elasticity for each regression. This average elasticity represents the average price response to a small change in demand

Schedule MM-R1

for a given zone, season, and period. Table 101 presents electric energy DRIPE elasticities in by zone, month, and period.[296]

Table 101. Energy DRIPE elasticities

Period	Month	ISO NE	ME	NH	VT	CT	RI	SEMA	NEMA	WCMA
Annual		1.3	1.4	1.4	1.4	1.3	1.3	1.4	1.3	1.3
Off-peak	**1**	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
	2	1.5	1.6	1.6	1.5	1.5	1.5	1.5	1.5	1.5
	3	1.4	1.5	1.4	1.4	1.3	1.4	1.4	1.4	1.4
	4	0.9	0.9	0.9	0.9	0.9	0.9	1.1	0.9	0.9
	5	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
	6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	7	1.2	1.1	1.2	1.2	1.2	1.1	1.2	1.2	1.2
	8	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1
	9	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.8	0.8
	10	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0
	11	1.0	1.1	1.1	1.0	1.0	1.0	1.0	1.1	1.0
	12	1.5	1.6	1.5	1.5	1.5	1.5	1.5	1.5	1.5
On-peak	**1**	2.5	2.5	2.4	2.5	2.5	2.5	2.4	2.4	2.5
	2	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
	3	1.4	1.5	1.4	1.5	1.4	1.4	1.4	1.4	1.4
	4	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
	5	0.9	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9
	6	1.1	1.0	1.0	1.1	1.1	1.0	1.0	1.0	1.0
	7	1.9	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9
	8	2.0	2.0	2.0	2.0	2.0	2.0	2.1	2.0	2.0
	9	1.0	0.9	0.9	1.0	1.0	1.0	1.1	1.0	1.0
	10	1.3	1.2	1.3	1.3	1.3	1.3	1.4	1.3	1.3
	11	1.2	1.3	1.2	1.2	1.2	1.2	1.2	1.2	1.2
	12	1.4	1.4	1.3	1.3	1.3	1.4	1.4	1.3	1.4

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 2024 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 1.3 percent reduction in price. Depending on the month, a 1.0 percent reduction in load throughout New England results in a 0.8 to 2.1 percent reduction in off-peak price, and a 0.8 to 2.5 percent reduction in peak price.

[296] We also calculate elasticities for "top" hours (described in footnote 295) using an analogous methodology. These elasticities are not shown in this report due the large size of the table but may be found in the *AESC 2024 User Interface*.

Schedule MM-R1

Comparison with AESC 2021

Table 102 describes the summary statistics from Table 101 and compares the results with analogous values from AESC 2021. Elasticities in AESC 2024 are generally very similar to those in AESC 2021, due in part to the fact that three of the five years of input data overlap between the two datasets).

Table 102. Comparison of energy DRIPE elasticities, AESC 2021 and 2024

		AESC 2021			AESC 2024		
		Min	*Median*	*Max*	*Min*	*Median*	*Max*
Annual		1.35	1.36	1.40	1.34	1.35	1.37
Winter	On-peak	0.87	1.38	2.71	0.75	1.34	2.50
	Off-peak	0.72	1.18	2.35	0.86	1.23	2.13
Summer	On-peak	0.65	1.50	2.22	0.92	1.48	2.06
	Off-peak	0.72	1.00	1.21	0.73	0.92	1.17

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 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.

The next subsection describes each of these two effects.

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

Schedule MM-R1

DRIPE value approximately one-fifth as large.[297] 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 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.[298]
2. **Hedging in Vermont**. Vermont is the sole remaining New England state that is vertically integrated statewide. Based on the 2021 IRP for Green Mountain Power, we assume

[297] There are subtle differences that make comparison inexact because DRIPE also depends on zonal elasticity and hedging estimates.

[298] We obtained data on these contracts from utility IRPs and FERC Form 1.

Schedule MM-R1

that all utilities in Vermont have about 50–90 percent of their energy hedged, depending on the year.[299]

3. **Hedging of vertically integrated energy in the other five New England states**. We estimate the resources owned or under contract to the vertically integrated utilities (various mixes of municipals and coops in the other five states) based on data from EIA 861.[300] 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.[301]

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 in previous AESC studies, 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 103 depicts the aggregate unhedged share of energy by year in Counterfactual #1.

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[299] For more, see https://greenmountainpower.com/wp-content/uploads/2021/12/2021-Integrated-Resource-Plan.pdf, Figure 7-5.

[300] EIA Form 861, 2015-2022. Available at https://www.eia.gov/electricity/data/eia861/.

[301] For example, we note that Belmont Light hedges up to 50 percent of its capacity and at least as much energy (see https://www.belmontlight.com/wp-content/uploads/2019/07/BMLD-Power-Supply-Policy-Updated-July-2019.pdf). Few vertically integrated utilities outside Vermont publish precise information on the amount of energy and capacity that is hedged. Ipswich Electric Light Department, for example, notes a 30 percent hedging target in its annual report, but also includes separate, long-term clean energy power purchase agreements that increase the *de facto* hedged percentage (see https://www.ipswichma.gov/DocumentCenter/View/14930/ELD-Annual-Report---FY23-Budget). Likewise, Middleborough Department of Public utilities notes that about 50 percent of its power was purchased in 2021, which suggests that the remaining 50 percent was hedged (https://www.mged.com/DocumentCenter/View/431/2021-DPU-Report-PDF).

Schedule MM-R1

Table 103. Percent of load assumed to be unhedged in Counterfactual #1

Year	ISO	CT	MA	ME	NH	RI	VT
2024	38%	23%	42%	46%	46%	40%	26%
2025	59%	36%	65%	74%	73%	60%	42%
2026	74%	51%	82%	92%	92%	63%	53%
2027	68%	56%	67%	92%	92%	63%	53%
2028	70%	59%	68%	92%	92%	64%	53%
2029	69%	60%	68%	85%	92%	65%	53%
2030	70%	68%	68%	79%	92%	66%	53%
2031	75%	88%	68%	79%	92%	67%	53%
2032	76%	89%	69%	80%	92%	68%	53%
2033	77%	89%	70%	80%	92%	69%	53%
2034	77%	89%	71%	81%	92%	70%	53%
2035	77%	89%	71%	81%	92%	71%	53%
2036	78%	89%	72%	82%	92%	71%	53%
2037	78%	89%	73%	82%	93%	72%	53%
2038	79%	90%	73%	83%	93%	73%	53%
2039	79%	88%	74%	83%	93%	74%	53%
2040	78%	83%	74%	83%	93%	74%	53%
2041	79%	86%	75%	84%	93%	75%	53%
2042	80%	90%	75%	84%	93%	76%	53%
2043	80%	90%	76%	84%	93%	76%	53%
2044	81%	91%	76%	85%	93%	76%	53%
2045	81%	91%	76%	85%	93%	77%	53%
2046	81%	91%	76%	85%	93%	77%	53%
2047	81%	91%	76%	86%	93%	78%	53%
2048	81%	91%	76%	86%	93%	78%	53%
2049	81%	91%	76%	86%	93%	78%	53%
2050	82%	91%	77%	86%	93%	78%	53%

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 2024 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 0.1 percent in 2024 and increase to 1 percent by 2036, where they are sustained through the study period.[302]

[302] Elasticities are derived from Burke, Paul J. et al. "The price elasticity of electricity demand in the United States: A three-dimensional analysis." Center for Applied Macroeconomic Analysis, 2018. Available at

Schedule MM-R1

3. **Impact from binding RPS policies.** For every MWh 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).[303] 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.

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 104, for Counterfactual #1, for measures installed in 2024.

Table 104. Energy DRIPE decay factors for measures installed in 2024 in Counterfactual #1

Year	ISONE	CT	MA	ME	NH	RI	VT
2024	95%	99%	93%	97%	96%	99%	71%
2025	94%	98%	92%	96%	96%	98%	69%
2026	93%	98%	91%	95%	95%	98%	66%
2027	92%	97%	90%	94%	94%	97%	64%
2028	91%	95%	88%	92%	92%	95%	61%
2029	88%	92%	86%	89%	90%	92%	57%
2030	84%	89%	82%	85%	86%	89%	53%
2031	79%	83%	76%	79%	80%	83%	40%
2032	70%	74%	68%	71%	72%	74%	34%
2033	58%	61%	56%	59%	59%	61%	27%
2034	40%	42%	38%	40%	41%	42%	18%
2035	0%	0%	0%	0%	0%	0%	0%
2036	0%	0%	0%	0%	0%	0%	0%
2037	0%	0%	0%	0%	0%	0%	0%
2038	0%	0%	0%	0%	0%	0%	0%
2039	0%	0%	0%	0%	0%	0%	0%
2040	0%	0%	0%	0%	0%	0%	0%
2041	0%	0%	0%	0%	0%	0%	0%
2042	0%	0%	0%	0%	0%	0%	0%
2043	0%	0%	0%	0%	0%	0%	0%
2044	0%	0%	0%	0%	0%	0%	0%
2045	0%	0%	0%	0%	0%	0%	0%
2046	0%	0%	0%	0%	0%	0%	0%
2047	0%	0%	0%	0%	0%	0%	0%
2048	0%	0%	0%	0%	0%	0%	0%
2049	0%	0%	0%	0%	0%	0%	0%
2050	0%	0%	0%	0%	0%	0%	0%

https://cama.crawford.anu.edu.au/sites/default/files/publication/cama_crawford_anu_edu_au/2017-08/50_2017_burke_abayasekara_0.pdf; and EIA Price Elasticity analysis, available at https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf.

[303] 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 8.2: *Applying non-embedded costs*.

Schedule MM-R1

Note: This decay schedule will vary for measures installed in other years, under other counterfactuals. See the AESC 2024 User Interface for detail on each counterfactual.

Energy DRIPE values

After combining the effects of the price shifts, unhedged demand, and decay, we can calculate the energy DRIPE benefits. Table 105 provides 15-year levelized energy DRIPE benefits for efficiency measures installed in 2024 using Equation 7 and Equation 8, for values installed in Massachusetts. 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 2024; values for measures installed in other years in other states may be calculated using the *AESC 2024 User Interface*.

Table 105. Illustrative energy DRIPE values for 2024 installations (2024 $ per MWh) for Counterfactual #1, for Massachusetts

		Winter		Summer	
		Intrazonal	*Interzonal*	*Intrazonal*	*Interzonal*
Off-peak	2024	$18.41	$18.25	$6.19	$5.89
	2025	$28.79	$28.73	$9.98	$9.52
	2026	$29.04	$29.07	$10.00	$9.60
	2027	$23.08	$28.27	$7.80	$9.22
	2028	$23.09	$28.05	$8.10	$9.45
	2029	$22.05	$26.27	$7.81	$9.00
	2030	$20.51	$25.00	$7.56	$9.00
	2031	$19.85	$26.73	$7.47	$9.88
	2032	$16.77	$22.28	$6.87	$8.98
	2033	$14.19	$18.56	$6.21	$7.98
	2034	$9.83	$12.69	$4.43	$5.60
On-peak	2024	$20.94	$20.61	$10.38	$9.69
	2025	$32.86	$32.54	$16.91	$15.81
	2026	$33.02	$32.83	$17.28	$16.22
	2027	$26.16	$31.87	$13.35	$15.46
	2028	$25.96	$31.41	$13.40	$15.56
	2029	$25.01	$29.69	$13.07	$14.92
	2030	$23.68	$28.62	$12.87	$15.05
	2031	$22.79	$30.64	$12.81	$16.69
	2032	$20.02	$26.51	$11.88	$15.33
	2033	$16.88	$22.04	$10.45	$13.33
	2034	$11.52	$14.87	$7.45	$9.42

Note: Values differ across states because states vary in terms of size of unhedged electricity demand.

Table 106 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. DRIPE values are broadly similar to those observed in AESC 2021 due to similarities in the DRIPE price shift component. Other factors that play a role in differences in DRIPE values include changes in energy prices (which are linked to changes in gas prices, clean energy deployment, and load), changes in load, and changes in hedging assumptions.

Schedule MM-R1

Table 106. Seasonal energy DRIPE values for measures installed in 2024 (2024 $ per MWh)

Type	Season	Period	CT	MA	ME	NH	RI	VT
Intrazonal	Summer	On-Peak	$4.63	$9.71	$2.33	$2.57	$1.49	$0.14
		Off-Peak	$2.69	$5.72	$1.49	$1.56	$0.84	$0.09
	Winter	On-Peak	$8.34	$18.03	$5.05	$5.14	$2.62	$0.32
		Off-Peak	$7.15	$15.72	$4.61	$4.51	$2.24	$0.28
Interzonal	Summer	On-Peak	$16.44	$10.87	$18.65	$18.34	$19.45	$20.66
		Off-Peak	$9.82	$6.49	$10.97	$10.86	$11.59	$12.26
	Winter	On-Peak	$31.50	$20.90	$34.65	$34.42	$36.99	$39.01
		Off-Peak	$27.66	$18.30	$30.10	$30.06	$32.37	$34.09

Note: Values shown are levelized over 15 years for Counterfactual #1.

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. This observation is largely borne out by observations in the most recent capacity auctions (see discussion in Chapter 5: *Avoided Capacity Costs*). However, when looking out over the past 5–10 auctions, we observe that the marginal sources of capacity do seem to 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.[304] 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 we use to calculate both types of capacity DRIPE. We begin with a discussion of price shifts, then describe for which components of regional demand these price shifts are eligible for application, then describe the methodologies for calculating benefits in the two categories of capacity DRIPE.

[304] 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.

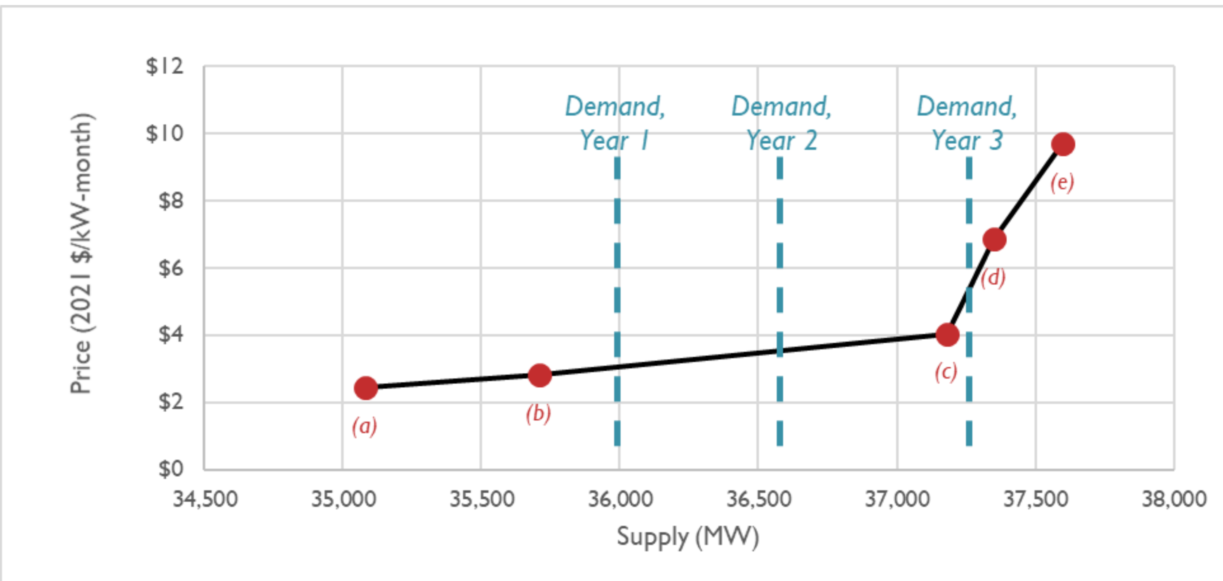
Schedule MM-R1

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 studies, for years utilizing the current capacity market structure (i.e., 2027 and prior years), we estimate price shifts for future years using the slope of the most recent capacity market auction (in the case of AESC 2024, this is FCA 17, conducted in February 2023), shifted to reflect the change in supply capacity that has occurred since that auction.

As an example, Figure 56 depicts the five known datapoints for supply and price in FCA 15.[305] 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 56, 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 107 for our estimates of the price shifts for each counterfactual.

Figure 56. 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.

[305] 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.

Schedule MM-R1

Table 107. Price shifts for capacity DRIPE (2024 $/kW-month per MW) in Rest-of-Pool region for current market structure

	FCA	CF# 1	CF# 2	CF# 3	CF# 4	CF# 5	CF# 6
2024	15	$0.00062	$0.00062	$0.00062	$0.00062	$0.00062	$0.00062
2025	16	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
2026	17	<$0.00001	<$0.00001	<$0.00001	<$0.00001	<$0.00001	<$0.00001
2027	18	<$0.00001	<$0.00001	<$0.00001	<$0.00001	<$0.00001	<$0.00001

Notes: Data on clearing prices for other counterfactuals and regions can be found in the AESC 2024 User Interface.

Under the new market structure (effective in 2028 and for all later years), we estimate price shifts based on the slopes of the demand curve and the modeled supply curve in the EnCompass model (see Table 108. Given the slopes of these curves at the capacity market clearing point, we calculate how much the price of capacity would change in response to a 1 MW change in accredited energy efficiency capacity shifting the supply curve right by participating in the market (cleared) or shifting the demand curve left by reducing the load forecast (uncleared). Note the change in units in Table 108, relative to Table 107; because these prices represent the addition of any summer and winter values, it is more intuitive to approach them from an entire-year perspective, rather than a month-by-month perspective.

In general, price shifts tend to be higher in years and in counterfactuals with higher capacity prices, as both trends (high capacity prices and large price shifts) are indicators of a tight capacity market.

Table 108. Price shifts for capacity DRIPE (2024 $/kW-month per MW) in Rest-of-Pool region for new market structure

	FCA	CF# 1	CF# 2	CF# 3	CF# 4	CF# 5	CF# 6
2028	19	$0.00057	$0.00059	$0.00034	$0.00367	$0.00042	$0.01111
2029	20	$0.00056	$0.00082	$0.00092	$0.00902	$0.00526	$0.01089
2030	21	$0.00071	$0.00117	$0.00156	$0.00998	$0.00593	$0.00927
2031	22	$0.00070	$0.00075	$0.00140	$0.00515	$0.00055	$0.00958
2032	23	$0.00045	$0.00365	$0.01036	$0.00954	$0.00579	$0.00819
2033	24	$0.00057	$0.00334	$0.00457	$0.00267	$0.00583	$0.00366
2034	25	$0.01235	$0.00106	$0.00534	$0.01504	$0.00093	$0.00694
2035	26	$0.00043	$0.00156	$0.00190	$0.00621	$0.00255	$0.00170
2036	27	$0.00054	$0.00408	$0.00030	$0.00039	$0.00146	$0.00556
2037	28	$0.01166	$0.00141	$0.01041	$0.00731	$0.00416	$0.00567
2038	29	$0.01185	$0.00132	$0.00079	$0.00588	$0.00759	$0.00388

Notes: Data on clearing prices for other counterfactuals and years can be found in the AESC 2024 User Interface.

During both capacity periods, the Rest-of-Pool price shift is used to estimate Rest-of-Pool capacity DRIPE impacts, except in cases where price separation occurs. See the next section for more information on these special cases.

Price separation

In two near-term years (FCA 15 and 16), AESC 2024 accounts for price separation. In these years, the auction had concluded prior to this study taking place. The results of both these auctions produced price separation in three regions. As they are modeled in AESC 2024, these regions include Northern New

Schedule MM-R1

England (Maine, New Hampshire, and Vermont), Southeast New England (SEMA, NEMA, and Rhode Island), and Rest-of-Pool (WCMA and Connecticut). In both of these years, the Northern New England region cleared at a price slightly lower than the Rest-of-Pool price, owing to it being export-constrained. Conversely, in both of these years, the Southeast New England region cleared at a price higher than the Rest-Of-Pool price, owing to it being import-constrained.

Due to limited available information on the auction supply curves of these three regions, we apply a different approach for estimating price shifts in these cases. First, to estimate the Rest-of-Pool price shift, we use the same methodology described in the above section, but incorporate the quantity of energy efficiency installed in just the Rest-of-Pool region to determine the price shift. Second, to estimate the price shifts in each of the other two regions, we examine how prices would have been different in each of these regions if the quantity of energy efficiency installed in these regions had been different by looking at the MRI curve specific to that region and auction.[306] Then, we evaluate the difference in prices between the actual clearing price and the second hypothetical clearing price, and divide the result by the quantity of energy efficiency modeled in that region. This produces a dollar-per-kW-month price shift for each price-separated region.

Table 109 summarizes the results of these estimations. We observe that the estimated price shifts for Northern New England and Southeast New England are between 1.6 and 60 times higher than the Rest-of-Pool price shift, depending on the year. In particular, we observe that the estimated price shift for Southeast New England in FCA 15 is a particularly large one, especially compared to other observed price shifts in the period for which conducted auction data is available.[307] This produces zone-on-zone capacity DRIPE values for FCA 15 (study year 2024, as modeled in FCA 2024) to be unusually high, compared to other years.

Modeled capacity DRIPE values in FCA 15 and FCA 16 are assigned to the six states as follows: first, Maine, New Hampshire, and Vermont all inherit the Northern New England value. Second, Connecticut inherits the Rest-of-Pool value. Third, Rhode Island inherits the Southeast New England value. Fourth, Massachusetts inherits a weighed average blend of the Rest-of-Pool and Southeast New England values, based on the projected summer peak values of its three constituent regions (WCMA, NEMA, and SEMA). Each region (Northern New England, Southeast New England, and Rest-of-Pool) is segmented into their own modeled capacity region. Zone-on-zone and zone-on-region DRIPE effects are then estimated independently for each of the three regions.

Because of a lack of information suggesting otherwise, we do not model price separation in any other years.

[306] ISO New England publishes subregional MRI curves for auctions with price separation, but not supply curve results.

[307] More specifically, while variations in price shifts of these estimated magnitudes are not unusual (see Table 107 and Table 108) a price shift with a value above $0.001/kW-month per MW *is* unusual.

Schedule MM-R1

Table 109. Price shifts in price-separated auctions (2024 $/kW-month per MW)

Price-separated region	FCA 15	FCA 16
Northern New England	$0.00099	$0.00037
Southeast New England	$0.00620	$0.00039
Rest-of-Pool	$0.00062	$0.00001

Note: All counterfactuals utilize the same set of price shifts.

Calculating capacity DRIPE

Price shifts are described in units of dollars-per-kW-month per MW (effectively, price per demand). To allow application of these numbers 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* and the methods described in Chapter 5: *Avoided Capacity Costs*. 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.[308] For Vermont, we estimate hedged demand percentages based on data from the most recently available Green Mountain Power IRP, and we assume hedged demand share in the rest of the state is similar.[309] 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 110 describes the resulting unhedged capacity demand assumptions for Counterfactual #1. See the *AESC 2024 User Interface* for detail on all counterfactuals.

[308] 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.

[309] Green Mountain Power 2021, "2021 Integrated Resource Plan." Figure 7-5. Accessed December 18, 2023. Available at https://greenmountainpower.com/wp-content/uploads/2021/12/2021-Integrated-Resource-Plan.pdf.

Schedule MM-R1

Table 110. Unhedged capacity for Counterfactual #1 (MW)

	ISO	CT	MA	ME	NH	RI	VT
2024	22,823	5,311	11,154	2,081	2,305	1,847	125
2025	23,608	5,371	11,445	2,076	2,330	1,904	482
2026	23,739	5,338	11,596	2,076	2,320	1,924	486
2027	25,381	5,654	12,521	2,187	2,434	2,064	520
2028	22,954	4,971	11,475	1,968	2,189	1,878	473
2029	23,578	5,075	11,823	2,021	2,239	1,934	487
2030	24,887	5,901	12,150	2,071	2,281	1,985	499
2031	25,014	5,861	12,264	2,085	2,293	2,007	504
2032	25,821	6,016	12,701	2,171	2,346	2,066	521
2033	25,926	6,044	12,560	2,246	2,435	2,073	568
2034	26,950	6,145	13,363	2,295	2,437	2,163	548
2035	27,540	6,231	13,697	2,354	2,485	2,210	563
2036	27,351	6,222	13,524	2,348	2,531	2,137	589
2037	28,114	6,143	14,086	2,470	2,575	2,214	627
2038	29,284	6,516	14,627	2,520	2,658	2,351	613
2039	29,204	6,320	14,649	2,574	2,699	2,301	661
2040	30,294	6,664	15,149	2,615	2,787	2,434	645
2041	30,947	6,769	15,481	2,673	2,868	2,491	665
2042	30,712	6,624	15,420	2,679	2,957	2,335	698
2043	31,284	6,637	15,693	2,775	2,973	2,480	726
2044	31,533	6,944	15,650	2,715	3,067	2,439	719
2045	32,594	7,063	16,184	2,871	3,118	2,649	709
2046	32,877	7,136	16,291	2,918	3,135	2,683	713
2047	33,148	7,206	16,396	2,964	3,149	2,716	717
2048	32,664	6,970	16,176	3,002	3,124	2,640	753
2049	33,660	7,345	16,600	3,044	3,173	2,773	725
2050	33,174	7,337	16,300	2,965	3,205	2,617	750

Notes: Data on hedged values 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 2024, as with 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 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 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). As a result, we assume that the effects of DRIPE fade out over time. Based on expert judgement, we use the same

Schedule MM-R1

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 111 shows the decay schedule used for cleared capacity measures installed in 2024. Measures installed in later years have the same decay schedule, but shifted by one or more years. This structure of decay does not change between the current modeled structure (2027 and prior years) and the new market structure (2028 and later years).

Table 111. Decay schedule used for cleared capacity for measures installed in 2024

	Decay	1- Decay
2024	0%	100%
2025	17%	83%
2026	33%	67%
2027	50%	50%
2028	67%	33%
2029	83%	17%
2030 through 2050	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 for replacing 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

$$Capacity\ DRIPE_{\substack{Zone\ Z\ |\ Zone\ Z \\ Period\ P}} = \left[Price\ Shift\ \times Hedged\ Capacity_{\substack{Zone\ Z \\ Period\ P}}\right] \times (1 - Decay)$$

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 112 shows cleared capacity DRIPE for each region for measures installed in 2024. In years with price separation, we use the Rest-of-Pool price shift to estimate Rest-of-Pool capacity DRIPE impacts,

Schedule MM-R1

regardless of whether a given region has price-separated in a particular auction.[310] Capacity DRIPE values can vary widely year-to-year, based on the price shift produced by the model (e.g., a price shift change of an order of magnitude between years will yield approximately an order of magnitude difference in terms of cleared capacity DRIPE). This is the principle driver behind the differences in capacity DRIPE values in AESC 2021 and AESC 2024.

Table 112. Cleared capacity DRIPE by year for measures installed in 2024 (2024 $ per kW-year)

	Zone-on-Zone DRIPE						Zone on Rest-of-Region DRIPE					
	CT	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2024	$39	$83	$25	$27	$137	$1	$130	$87	$145	$142	$32	$168
2025	$0	$1	$8	$9	$7	$2	$1	$1	$0	$0	$0	$0
2026	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2028	$0	$0	$0	$0	$0	$0	$41	$26	$48	$47	$48	$51
2029	$0	$0	$0	$0	$0	$0	$21	$13	$25	$24	$25	$26
2030	$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
2032	$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
2034	$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
2036	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2037	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15-year levelized	**$3**	**$6**	**$2**	**$3**	**$11**	**$0**	**$14**	**$9**	**$16**	**$16**	**$7**	**$18**

Calculating uncleared capacity DRIPE

Measures that are not bid into or do not clear the FCM also generate capacity DRIPE benefits, albeit with different timing and of different magnitudes.[311] We calculate capacity DRIPE for uncleared resources analogously to that of cleared resources, but we adjust the decay schedule and market clearing prices 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 several years after a measure is installed (five years when discussing measure impacts prior to 2028, and three years when discussing measure impacts that accrue in 2028 and later years), and that they persist at various magnitudes and

[310] In some circumstances, this yields a negative rest-of-region DRIPE effect, because the in-zone impacts are larger than the Rest-of-Pool impacts. In these circumstances, we assume a zero value for rest-of-region capacity DRIPE.

[311] These measures include energy efficiency measures that program administrators choose to not bid into the market due to administrative burden, demand response or load management measures that do not clear the capacity market but are nonetheless built for policy reasons, or building electrification measures which may produce demand increases (and therefore "negative savings").

Schedule MM-R1

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 111.

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.[312]

- 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 112 shows uncleared capacity DRIPE for each region for measures installed in 2024, assuming a measure life of 10 years. As with cleared capacity DRIPE, uncleared capacity DRIPE values can vary widely year-to-year, based on the price shift produced by the model (e.g., a price shift change of an order of magnitude between years will yield approximately an order of magnitude difference in terms of cleared capacity DRIPE). Compared to cleared capacity DRIPE, uncleared capacity DRIPE values tend to be higher, but accrue later. This is due to higher capacity prices—and associated capacity price shifts—forecasted for the mid to long term.

[312] 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.

Schedule MM-R1

Table 113. Uncleared capacity DRIPE by year for measures installed in 2024 (2024 $ per kW-year)

	Zone-on-Zone DRIPE						Zone on Rest-of-Region DRIPE					
	CT	*MA*	*ME*	*NH*	*RI*	*VT*	*CT*	*MA*	*ME*	*NH*	*RI*	*VT*
2024	$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
2026	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2027	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2028	$20	$47	$8	$9	$8	$2	$74	$47	$86	$85	$86	$92
2029	$23	$53	$9	$10	$9	$2	$83	$53	$97	$96	$97	$104
2030	$30	$63	$11	$12	$10	$3	$98	$66	$118	$117	$118	$126
2031	$22	$45	$8	$8	$7	$2	$70	$47	$84	$84	$85	$90
2032	$9	$18	$3	$3	$3	$1	$28	$19	$34	$34	$34	$36
2033	$6	$13	$2	$2	$2	$1	$20	$14	$24	$24	$24	$26
2034	$60	$130	$22	$24	$21	$5	$202	$132	$240	$238	$241	$257
2035	$1	$1	$0	$0	$0	$0	$2	$1	$2	$2	$2	$2
2036	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2037	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2038	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
15-year levelized	**$11**	**$24**	**$4**	**$5**	**$4**	**$1**	**$38**	**$25**	**$45**	**$45**	**$45**	**$48**

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 2024 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 2024 would be equal to the sum of the values from 2024 through 2058, regardless of whether that measure had a 1-year measure life or a 30-year measure life.[313]

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 113 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. Because we expect ISO New England's use of the load regressions used for each individual year to be unchanged under the new market structure, we determine that the scaling effects described in *Appendix K: Scaling Factor for Uncleared Resources* can be applied to benefits accruing under both the current market structure and the assumed new market structure that is effective in 2028.

[313] 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.

Schedule MM-R1

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 applied to end-use measures that produce natural gas savings.

Calculating elasticities

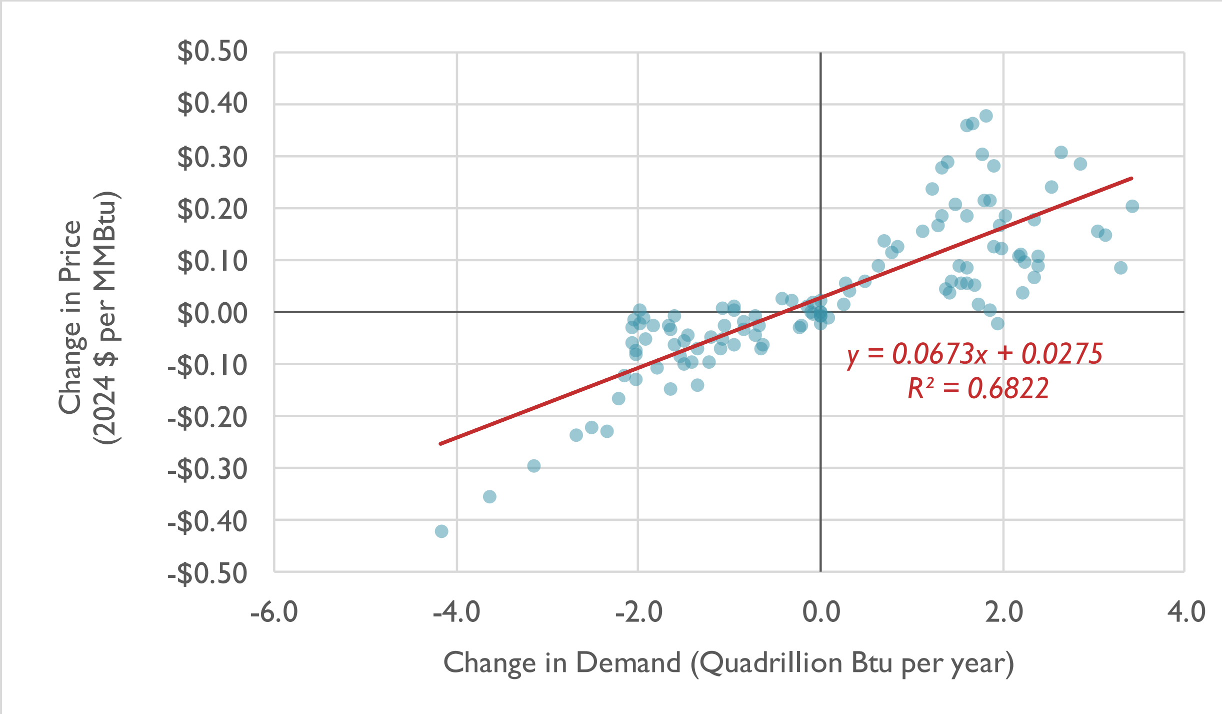
Elasticity describes how prices of a commodity respond to changes in demand. As in AESC 2021, AESC 2024 relies on a calculation of the implied response of natural gas prices to supply changes observed in different scenarios modeled in EIA's AEO 2023.

Figure 57 compares annual data points from AEO 2023. 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 the AEO 2023 Reference case for the same year. This figure includes datapoints from four different AEO side-scenarios: the High economic growth, Low economic growth, High Zero-Carbon Technology Cost, and Low Zero-Carbon Technology Cost. This analysis encompasses all years from 2022 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 $0.067 per MMBtu in 2024 dollars. This is about three-quarters of the AESC 2021 value of $0.094/MMBtu per quadrillion Btu/year (in 2024 dollars).

Schedule MM-R1

Figure 57. Effect of changing gas demand on gas price



Note: Deltas compare annual prices and demand in four AEO 2023 scenarios versus the AEO 2023 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 2023, each year, New England is expected to consume about 0.6 quadrillion Btu for non-electric uses.[314] Multiplying this quantity by the price shift ($0.067/MMBtu per quadrillion Btu) yields a natural gas supply DRIPE effect of $0.04 per MMBtu. The quantity of gas consumed for non-electric uses changes over time, and among states. Between 2024 and 2050, AEO 2023 estimates that non-electric gas demand will increase by about 6 percent. Demand in each state is projected based on recent historical observations from 2016 through 2021. 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

[314] 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.

Schedule MM-R1

the effect of demand on the marginal cost of extraction for a finite resource. If anything, lower gas usage in 2024 will leave more low-cost gas in the ground to meet demand in 2025, 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 contracts 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 114 describes this impact schedule for measures installed in 2024. 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 114. 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
2024	50%	50%
2025	20%	80%
2026	0%	100%
…	…	…
2038 and later	0%	100%

Note: Values shown are for measures installed in 2024. Measures installed in 2025 would see these effects shifted by one year, measures installed in 2026 would see these effects shifted by two years, and so on.

Natural gas supply DRIPE values

Table 115 depicts the value of demand reduction for each state. We calculate this by obtaining the product of (a) the price shift (in 2024 $/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.[315] Table 115 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 2025 yields a gas supply DRIPE benefit of $0.035 for New England as a whole.

AESC 2024's gas supply DRIPE estimates are lower than those found in AESC 2021, mostly due to lower price shift ($0.067/MMBtu per quadrillion Btu, down from $0.094/MMBtu per quadrillion Btu). Other changes are due to differences in historical gas consumption and projected gas consumption across the six states.

[315] 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 2: *Avoided Natural Gas Costs*.

Schedule MM-R1

Table 115. Natural gas supply DRIPE benefit (2024 $ 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*
2024	0.018	0.005	0.010	0.001	0.001	0.001	0.000	0.014	0.008	0.017	0.018	0.017	0.018
2025	0.030	0.007	0.016	0.002	0.001	0.002	0.001	0.022	0.013	0.028	0.028	0.027	0.029
2026	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2027	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2028	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2029	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2030	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2031	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2032	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.034	0.036
2033	0.037	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.035	0.035	0.036
2034	0.038	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.036	0.035	0.037
2035	0.038	0.009	0.020	0.002	0.002	0.003	0.001	0.028	0.017	0.035	0.036	0.035	0.037
2036	0.038	0.009	0.021	0.002	0.002	0.003	0.001	0.029	0.017	0.035	0.036	0.035	0.037
2037	0.038	0.009	0.021	0.002	0.002	0.003	0.001	0.029	0.017	0.036	0.036	0.035	0.037
2038	0.038	0.009	0.021	0.002	0.002	0.003	0.001	0.029	0.017	0.036	0.036	0.035	0.037
15-year levelized	**0.035**	**0.009**	**0.019**	**0.002**	**0.002**	**0.003**	**0.001**	**0.027**	**0.016**	**0.033**	**0.034**	**0.033**	**0.034**

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

As in previous AESC studies, the majority of the price differential for natural gas in New England is assumed to be 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.[316]

[316] To be clear, this calculation of DRIPE ignores effects from gas delivered to New England directly from Canada or from LNG.

Schedule MM-R1

Using data spanning three winters December 2020 through March 2023, we examine prices and demand for gas to determine price shifts over different periods of time.[317] 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.[318] 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.[319] 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 116 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 2: *Avoided Natural Gas Costs*.

Table 116. Gas basis price shifts by season

Season	Months included	Basis price shift (2024 $/MMBtu per BBtu/day)
Summer, electric	June through September	0.00036
Winter, electric	October through May	0.00447
Summer, gas	April through October	0.00032
Winter, gas	November through March	0.00687
Annual	**All months**	**0.00306**

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 117. Note that this schedule is for measures installed in 2024; measures installed in later years (e.g., 2025, 2026, and so on) use this same decay schedule but shifted by one year.

[317] We note that the time period analyzed for natural gas DRIPE purposes is narrower than the period evaluated for energy DRIPE purposes (i.e., three years versus five years). Reliance on this more limited dataset is due to data availability issues.

[318] Prices obtained from research performed by Natural Gas Intelligence (NGI). More details can be found at: https://www.naturalgasintel.com/

[319] Prices obtained from Natural Gas Intelligence's (NGI's) "Daily" subscription service. More details on this service can be found at: https://www.naturalgasintel.com/

Schedule MM-R1

Table 117. Percent of gas basis decayed by year for measures installed in 2024

	Gas Basis Decay (%)
2024	1.3%
2025	4.1%
2026	6.8%
2027	16.3%
2028	25.4%
2029	46.8%
2030	67.0%
2031	76.0%
2032	84.5%
2033	92.5%
2034 and all following years	100.0%

We then apply these decay percentages to the price shifts described above. Table 118 shows the decayed basis values for a measure installed in 2024, 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 118. Decayed natural gas DRIPE values (2024 $/MMBtu per Quadrillion Btu reduced)

	Basis					Supply
	Electricity Summer	Electricity Winter	Gas Summer	Gas Winter	Annual	Annual
2024	0.0029	0.0181	0.0015	0.0449	0.0083	0.0001
2025	0.0028	0.0176	0.0014	0.0436	0.0080	0.0001
2026	0.0028	0.0171	0.0014	0.0424	0.0078	0.0001
2027	0.0025	0.0154	0.0012	0.0380	0.0070	0.0001
2028	0.0022	0.0137	0.0011	0.0339	0.0063	0.0001
2029	0.0016	0.0098	0.0008	0.0242	0.0045	0.0001
2030	0.0010	0.0061	0.0005	0.0150	0.0028	0.0001
2031	0.0007	0.0044	0.0004	0.0109	0.0020	0.0001
2032	0.0005	0.0029	0.0002	0.0071	0.0013	0.0001
2033	0.0002	0.0014	0.0001	0.0034	0.0006	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
2036	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2037	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001
2038	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.

Schedule MM-R1

Basis price shifts are not outright applied to any measures. Instead, we combine them with several other factors and use them 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 2024 values with analogous values from AESC 2021.

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*: $0.067/MMBtu per quadrillion Btu. Next, we convert this price shift's units into $-per-MWh per quadrillion Btu so that we can apply it to MWh savings. We do this by relying on data about the marginal heat rate for emitting plants as reported by ISO New England.[320] According to this data, the marginal emitting plant heat rate is 7.902 MMBtu per MWh.[321] 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 6.56 MMBtu per MWh.[322] We can then multiply this value by the price shift to produce an estimate of $0.54/MWh per quadrillion Btu (see Equation 11).

Equation 11. Price shift in dollar-per-MWh terms

$$Dollar\ per\ MWh\ price\ shift = dollar\ per\ MMBtu\ price\ shift \times marginal\ gas\ heat\ rate$$

$$= \frac{\frac{\$0.067}{MMBtu}}{Quadrillion\ Btu} \times \frac{6.56\ MMBtu}{MWh} = \frac{\frac{\$0.44}{MWh}}{Quadrillion\ Btu}$$

To determine E-G DRIPE, we 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 114), and (c) the price shift.

[320] ISO New England. April 2023. *2021 Electric Generator Air Emissions Report.* Available at https://www.iso-ne.com/static-assets/documents/2023/04/2021-air-emissions-report.pdf.

[321] Id, Section 5.3.1.2.

[322] According to ISO New England, from 2018 to 2021, natural gas plants and pumped storage plants (which are generally powered by marginal units) were marginal 83 percent of the time (see 2020 Air Emissions Report, Figure 4-9).

Schedule MM-R1

Table 119. Electric-to-gas (E-G) cross-DRIPE benefit (2024 $ 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*
2024	0.120	0.029	0.066	0.007	0.006	0.009	0.003	0.091	0.055	0.113	0.114	0.112	0.117
2025	0.193	0.047	0.105	0.012	0.010	0.014	0.005	0.146	0.088	0.181	0.183	0.179	0.188
2026	0.242	0.059	0.131	0.015	0.012	0.018	0.006	0.183	0.110	0.227	0.229	0.224	0.236
2027	0.241	0.059	0.131	0.015	0.012	0.018	0.006	0.182	0.110	0.226	0.229	0.223	0.235
2028	0.242	0.059	0.132	0.015	0.012	0.018	0.006	0.183	0.110	0.227	0.230	0.224	0.236
2029	0.242	0.059	0.132	0.015	0.012	0.018	0.006	0.183	0.110	0.227	0.230	0.224	0.236
2030	0.242	0.059	0.132	0.015	0.012	0.018	0.006	0.183	0.110	0.227	0.230	0.224	0.236
2031	0.243	0.059	0.132	0.015	0.012	0.018	0.006	0.183	0.111	0.227	0.230	0.225	0.236
2032	0.243	0.059	0.132	0.015	0.012	0.018	0.006	0.184	0.111	0.228	0.231	0.225	0.237
2033	0.244	0.060	0.133	0.015	0.012	0.018	0.006	0.184	0.111	0.229	0.231	0.226	0.238
2034	0.245	0.060	0.133	0.015	0.012	0.018	0.006	0.185	0.111	0.229	0.232	0.226	0.238
2035	0.245	0.060	0.133	0.015	0.012	0.018	0.006	0.185	0.112	0.230	0.233	0.227	0.239
2036	0.246	0.060	0.134	0.015	0.012	0.018	0.006	0.186	0.112	0.231	0.234	0.228	0.240
2037	0.247	0.060	0.134	0.015	0.012	0.018	0.006	0.187	0.113	0.232	0.234	0.229	0.241
2038	0.248	0.060	0.135	0.015	0.012	0.018	0.006	0.187	0.113	0.232	0.235	0.229	0.241
15-year levelized	**0.231**	**0.056**	**0.125**	**0.014**	**0.012**	**0.017**	**0.006**	**0.174**	**0.105**	**0.216**	**0.219**	**0.213**	**0.225**

Note: Values differ across states because states vary in terms of size of non-electric gas consumption.

Using this table, we can estimate the benefit for a reduction in gas use in each year. For example, a 1 MWh reduction in electricity demand in 2024 yields an E-G cross-DRIPE benefit of $0.120 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 2024's electric-to-gas DRIPE estimates are lower than those found in AESC 2021, mostly due to lower price shift ($0.067/MMBtu per quadrillion Btu, down from $0.094/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 118. To calculate the price shift for each season, we add the supply price shift (which does not vary by season) to

Schedule MM-R1

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 2034, 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. We scale this total quantity of energy by the portion of energy 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 103. Because system load changes across counterfactuals, the unhedged percentage also changes.

Table 120 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.

Schedule MM-R1

Table 120. Gas-to-electric cross-fuel heating DRIPE, 2024 gas efficiency installations (2024 $ 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)	2024	$2.30	$0.36	$1.15	$0.30	$0.30	$0.17	$0.01	$1.94	$1.15	$2.00	$2.01	$2.13	$2.29
	2025	$3.58	$0.56	$1.79	$0.48	$0.47	$0.26	$0.03	$3.02	$1.79	$3.10	$3.11	$3.32	$3.55
	2026	$4.49	$0.78	$2.24	$0.58	$0.58	$0.27	$0.04	$3.71	$2.25	$3.91	$3.92	$4.23	$4.45
	2027	$3.87	$0.78	$1.73	$0.54	$0.53	$0.26	$0.03	$3.09	$2.14	$3.33	$3.34	$3.61	$3.84
	2028	$3.57	$0.74	$1.60	$0.48	$0.47	$0.24	$0.03	$2.83	$1.97	$3.09	$3.10	$3.33	$3.55
	2029	$2.55	$0.54	$1.16	$0.32	$0.34	$0.18	$0.02	$2.02	$1.40	$2.23	$2.21	$2.38	$2.53
	2030	$1.61	$0.37	$0.72	$0.18	$0.21	$0.11	$0.01	$1.23	$0.89	$1.42	$1.40	$1.49	$1.59
	2031	$1.21	$0.34	$0.51	$0.13	$0.15	$0.08	$0.01	$0.87	$0.70	$1.08	$1.07	$1.13	$1.20
	2032	$0.73	$0.20	$0.31	$0.08	$0.09	$0.05	$0.01	$0.53	$0.42	$0.65	$0.65	$0.69	$0.73
	2033	$0.32	$0.09	$0.14	$0.04	$0.04	$0.02	$0.00	$0.23	$0.18	$0.29	$0.28	$0.30	$0.32
	2034	$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
	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
	2036	$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
	2037	$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
	2038	$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)	2024	$5.09	$0.80	$2.54	$0.68	$0.67	$0.37	$0.03	$4.29	$2.56	$4.41	$4.42	$4.72	$5.06
	2025	$7.91	$1.23	$3.93	$1.08	$1.06	$0.55	$0.06	$6.68	$3.98	$6.83	$6.85	$7.36	$7.85
	2026	$9.96	$1.72	$4.94	$1.33	$1.30	$0.58	$0.10	$8.25	$5.03	$8.64	$8.66	$9.38	$9.86
	2027	$8.58	$1.72	$3.82	$1.22	$1.19	$0.56	$0.07	$6.86	$4.76	$7.36	$7.39	$8.02	$8.51
	2028	$7.92	$1.63	$3.54	$1.10	$1.07	$0.52	$0.06	$6.29	$4.38	$6.82	$6.85	$7.40	$7.86
	2029	$5.64	$1.18	$2.55	$0.73	$0.76	$0.38	$0.05	$4.47	$3.10	$4.91	$4.88	$5.26	$5.60
	2030	$3.53	$0.81	$1.57	$0.42	$0.46	$0.24	$0.03	$2.71	$1.96	$3.11	$3.06	$3.29	$3.50
	2031	$2.65	$0.73	$1.11	$0.29	$0.32	$0.17	$0.02	$1.92	$1.54	$2.36	$2.33	$2.48	$2.63
	2032	$1.59	$0.43	$0.67	$0.18	$0.19	$0.10	$0.01	$1.15	$0.91	$1.41	$1.39	$1.48	$1.57
	2033	$0.67	$0.18	$0.28	$0.07	$0.08	$0.04	$0.01	$0.49	$0.38	$0.59	$0.59	$0.62	$0.66
	2034	$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
	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
	2036	$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
	2037	$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
	2038	$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 2024 is $1.72 per MMBtu. The winter value ($3.80 per MMBtu) is over 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 121 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2021 and AESC 2024. Gas-to-electric cross-DRIPE values in AESC 2024 are generally higher than in AESC 2021, largely as a result of changes in DRIPE coefficients and hedged energy assumptions.

Schedule MM-R1

Table 121. Comparison of levelized gas-to-electric (G-E) cross-DRIPE benefits (2024 $ per MMBtu)

	ISO NE	CT	MA	ME	NH	RI	VT
Annual							
AESC 2021	1.03	0.17	0.48	0.14	0.13	0.08	0.02
AESC 2024	1.72	0.34	0.81	0.22	0.22	0.12	0.01
Difference ($)	0.70	0.17	0.33	0.09	0.09	0.03	-0.01
Difference (%)	68%	99%	68%	64%	70%	41%	-45%
Winter / Space heating							
AESC 2021	1.87	0.31	0.87	0.25	0.24	0.14	0.05
AESC 2024	3.80	0.74	1.78	0.51	0.51	0.25	0.03
Difference ($)	1.94	0.43	0.90	0.26	0.26	0.11	-0.01
Difference (%)	104%	138%	103%	102%	109%	74%	-32%

Note: All values are levelized over 15 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 118. 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 2034, the "total" price shift for E-G-E cross-DRIPE 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, we then multiply these price shifts 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 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 103.

Table 122 summarizes the E-G-E values for the annual period: these are the values that appear in the *AESC 2024 User Interface* and are applied by program administrators using Appendix B. Table 123 summarizes the summer and winter effects for historical comparison with AESC 2021. These values are not used in cost-effectiveness testing (except to the degree that the seasonal price shifts inform the annual price shift).

Schedule MM-R1

Table 122. Annual electric-to-gas-to-electric cross-fuel heating DRIPE, 2024 gas efficiency installations (2024 $ 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	2024	$15.02	$2.37	$7.53	$1.96	$1.94	$1.12	$0.10	$12.65	$7.49	$13.06	$13.08	$13.90	$14.93
	2025	$23.34	$3.67	$11.66	$3.11	$3.06	$1.67	$0.17	$19.67	$11.68	$20.23	$20.28	$21.67	$23.17
	2026	$29.30	$5.09	$14.61	$3.81	$3.75	$1.74	$0.29	$24.21	$14.69	$25.49	$25.54	$27.56	$29.01
	2027	$25.23	$5.11	$11.30	$3.50	$3.44	$1.68	$0.19	$20.12	$13.93	$21.73	$21.79	$23.55	$25.04
	2028	$23.29	$4.84	$10.46	$3.16	$3.09	$1.56	$0.18	$18.45	$12.83	$20.13	$20.20	$21.73	$23.11
	2029	$16.64	$3.50	$7.54	$2.10	$2.21	$1.15	$0.13	$13.14	$9.10	$14.54	$14.43	$15.49	$16.51
	2030	$10.46	$2.44	$4.67	$1.20	$1.36	$0.72	$0.07	$8.03	$5.79	$9.26	$9.11	$9.74	$10.39
	2031	$7.89	$2.19	$3.33	$0.85	$0.95	$0.52	$0.05	$5.70	$4.57	$7.04	$6.95	$7.38	$7.84
	2032	$4.78	$1.32	$2.03	$0.52	$0.57	$0.32	$0.03	$3.47	$2.75	$4.26	$4.22	$4.47	$4.75
	2033	$2.09	$0.57	$0.89	$0.23	$0.25	$0.14	$0.02	$1.52	$1.20	$1.86	$1.84	$1.95	$2.07
	2034	$0.14	$0.04	$0.06	$0.02	$0.02	$0.01	$0.00	$0.10	$0.08	$0.13	$0.13	$0.13	$0.14
	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
	2036	$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
	2037	$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
	2038	$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 123. Seasonal electric-to-gas-to-electric cross-fuel heating DRIPE, 2024 gas efficiency installations (2024 $ 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	2024	$1.93	$0.31	$0.98	$0.24	$0.24	$0.15	$0.01	$1.62	$0.96	$1.69	$1.69	$1.78	$1.92
	2025	$3.00	$0.48	$1.51	$0.38	$0.38	$0.22	$0.02	$2.52	$1.49	$2.62	$2.62	$2.78	$2.98
	2026	$3.76	$0.67	$1.89	$0.47	$0.47	$0.23	$0.03	$3.10	$1.87	$3.30	$3.29	$3.53	$3.73
	2027	$3.24	$0.67	$1.46	$0.43	$0.43	$0.22	$0.02	$2.57	$1.78	$2.81	$2.81	$3.02	$3.22
	2028	$2.99	$0.63	$1.35	$0.39	$0.39	$0.21	$0.02	$2.36	$1.64	$2.60	$2.60	$2.78	$2.97
	2029	$2.15	$0.46	$0.98	$0.26	$0.28	$0.15	$0.02	$1.69	$1.17	$1.89	$1.87	$2.00	$2.13
	2030	$1.37	$0.32	$0.62	$0.15	$0.17	$0.10	$0.01	$1.05	$0.76	$1.22	$1.20	$1.27	$1.36
	2031	$1.05	$0.30	$0.44	$0.11	$0.12	$0.07	$0.01	$0.75	$0.61	$0.94	$0.93	$0.98	$1.04
	2032	$0.65	$0.18	$0.28	$0.07	$0.08	$0.04	$0.00	$0.47	$0.37	$0.58	$0.58	$0.61	$0.65
	2033	$0.31	$0.08	$0.13	$0.03	$0.04	$0.02	$0.00	$0.22	$0.17	$0.27	$0.27	$0.28	$0.30
	2034	$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
	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
	2036	$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
	2037	$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
	2038	$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	2024	$21.01	$3.29	$10.47	$2.81	$2.76	$1.54	$0.14	$17.73	$10.54	$18.20	$18.26	$19.47	$20.87
	2025	$32.67	$5.09	$16.24	$4.46	$4.35	$2.29	$0.25	$27.59	$16.43	$28.21	$28.32	$30.38	$32.43
	2026	$41.04	$7.06	$20.36	$5.47	$5.33	$2.39	$0.42	$33.98	$20.68	$35.57	$35.70	$38.64	$40.62
	2027	$35.37	$7.09	$15.76	$5.03	$4.89	$2.31	$0.28	$28.28	$19.61	$30.35	$30.48	$33.06	$35.09
	2028	$32.68	$6.73	$14.61	$4.54	$4.39	$2.15	$0.26	$25.95	$18.07	$28.14	$28.29	$30.53	$32.42
	2029	$23.31	$4.86	$10.52	$3.02	$3.14	$1.58	$0.19	$18.45	$12.78	$20.29	$20.17	$21.73	$23.11
	2030	$14.60	$3.37	$6.49	$1.72	$1.92	$0.99	$0.11	$11.23	$8.10	$12.88	$12.68	$13.60	$14.49
	2031	$10.96	$3.02	$4.61	$1.22	$1.33	$0.70	$0.08	$7.94	$6.35	$9.75	$9.63	$10.26	$10.89
	2032	$6.60	$1.80	$2.79	$0.73	$0.79	$0.43	$0.05	$4.80	$3.80	$5.86	$5.80	$6.17	$6.55
	2033	$2.81	$0.76	$1.20	$0.31	$0.33	$0.18	$0.02	$2.05	$1.61	$2.49	$2.47	$2.63	$2.79
	2034	$0.09	$0.02	$0.04	$0.01	$0.01	$0.01	$0.00	$0.07	$0.05	$0.08	$0.08	$0.09	$0.09
	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
	2036	$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
	2037	$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
	2038	$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 2024 is $11.23 per MMBtu. As with G-E cross-DRIPE, the winter value ($15.71 per MMBtu) is larger because of the higher basis values in the winter months, while the summer value ($1.46 per MMBtu is smaller) because of the

Schedule MM-R1

corresponding unimportance of the basis in these 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 124 provides a comparison of gas-on-electric cross-DRIPE effects between AESC 2021 and AESC 2024. As with G-E cross-DRIPE, E-G-E cross-DRIPE values in AESC 2024 are generally higher than in AESC 2021, largely as a result of changes in DRIPE coefficients and hedged energy assumptions.

Table 124. Comparison of 15-year levelized electric-to-gas-to-electric (E-G-E) cross-DRIPE benefits (2024 $ per MWh)

	ISO NE	CT	MA	ME	NH	RI	VT
Electric Annual							
AESC 2021	6.60	1.09	3.10	0.88	0.85	0.53	0.16
AESC 2024	11.23	2.20	5.27	1.46	1.47	0.76	0.09
Difference ($)	4.63	1.11	2.17	0.58	0.62	0.23	-0.07
Difference (%)	70%	101%	70%	66%	72%	43%	-44%
Electric Summer							
AESC 2021	1.40	0.24	0.66	0.17	0.18	0.12	0.03
AESC 2024	1.46	0.29	0.69	0.18	0.19	0.10	0.01
Difference ($)	0.06	0.05	0.03	0.01	0.01	-0.02	-0.02
Difference (%)	4%	23%	4%	3%	6%	-15%	-67%
Electric Winter							
AESC 2021	7.12	1.16	3.33	0.98	0.93	0.55	0.18
AESC 2024	15.71	3.04	7.34	2.09	2.08	1.04	0.13
Difference ($)	8.58	1.88	4.01	1.11	1.15	0.48	-0.05
Difference (%)	120%	161%	120%	114%	123%	88%	-27%

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 2024, 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 2023 for years 2024–2038.

Schedule MM-R1

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 125 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 $8.6 per barrel. In other words, it indicates that a 1.0 percent increase in cumulative oil production in this region would increase costs by 0.86 percent.

Table 125. 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	2019	0.86	(A)
Rystad Energy	Entire curve	2022	1.45	(B)
Goldman Sachs	Low only	2023	0.57	(C)
Goldman Sachs	High only	2023	3.07	(C)
BP/PIRA	Low only	2015	0.88	(D)
BP/PIRA	High only	2015	3.60	(D)
S&P Global	Entire Curve	2021	0.63	(E)
Average (All)			**1.58**	
Average (Low Only + Entire Curve)			**0.88**	

Sources: (A) https://www.woodmac.com/reports/upstream-oil-and-gas-global-oil-cost-curves-and-pre-fid-breakevens-updated-h2-2018-211878/, (B) https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/863800/fossil-fuel-supply-curves.pdf, (C) http://crudeoilpeak.info/oil-price-analysis, (D) https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/news-and-insights/speeches/new-economics-of-oil-spencer-dale.pdf, and (E) https://www.spglobal.com/commodityinsights/en/ci/research-analysis/global-crude-oil-curve-shows-projects-break-even-through-2040.html.

A simple average of all elasticities yields a value of 1.58. If the two "High only" slopes are removed, the resulting average elasticity is 0.88. Given the uncertain nature of this analysis, AESC 2024 models oil supply as unit elastic in the relevant region study, so a 1 percent change in demand would yield a 1

Schedule MM-R1

percent change in price.[323] Critically, demand in this context is *global demand* (currently 101 million barrels/day, of which the United States consumes about one-fourth.[324]

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) changes in response to changes in demand (measured in quadrillion Btu per year). To do this, we multiply the elasticity by a forecast for WTI crude oil prices ($16 to $18 per MMBtu, depending on the year) and divide the result by a forecast of crude oil consumption (estimated to be about 240 quadrillion Btu worldwide per year).[325] This yields an average price shift of about $0.07/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 0.76 percent of worldwide consumption), the overall value of DRIPE remains modest.[326]

According to the latest EIA SEDS database, in 2014 through 2021, New England consumed approximately 1.4 quadrillion Btu of petroleum products yearly.[327] Over time, AEO 2023 forecasts demand gradually falling, averaging about 1.04 quadrillion Btu of petroleum products yearly between 2024 and 2050.

As a result, a 1 MMBtu reduction in crude oil demand yields an average regional benefit of about $0.07 per MMBtu (i.e., $0.07/MMBtu per quadrillion Btu multiplied by 1.04 quadrillion Btu). The value for each state, presented in Table 126, are proportionally smaller, ranging from about $0.005 per MMBtu to

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323 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.

324 For more information, see https://www.iea.org/oilmarketreport/omrpublic/.

325 Crude oil prices are based on WTI prices from AEO 2023 and worldwide crude oil consumption is based on values in EIA's 2021 edition of the International Energy Outlook.

EIA. Last accessed August 10, 2023. "Petroleum and Other Liquids Prices." *Eia.org.* Available at https://www.eia.gov/outlooks/aeo/excel/aeotab_12.xlsx.

EIA. 2021. "Liquids Consumption: OECD: OECD Americas." *EIA.gov*. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=5-IEO2019&sourcekey=0.

326 Calculated based on data from 2014 to 2021 using data from EIA. 2021. "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

327 See https://www.eia.gov/state/seds/seds-data-fuel.php?sid=US#DataFiles for more information.

Schedule MM-R1

$0.033 per MMBtu per 1 MMBtu reduction.[328] 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.

Table 126. Crude oil DRIPE by state (2024 $ 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*
2024	0.096	0.022	0.040	0.012	0.011	0.006	0.006	0.074	0.057	0.084	0.085	0.091	0.091
2025	0.088	0.020	0.036	0.011	0.010	0.005	0.005	0.068	0.052	0.077	0.078	0.083	0.083
2026	0.086	0.020	0.035	0.011	0.010	0.005	0.005	0.066	0.051	0.075	0.076	0.081	0.081
2027	0.085	0.019	0.035	0.011	0.010	0.005	0.005	0.065	0.050	0.074	0.075	0.080	0.080
2028	0.083	0.019	0.034	0.011	0.010	0.005	0.005	0.064	0.049	0.073	0.074	0.078	0.079
2029	0.082	0.019	0.034	0.011	0.009	0.005	0.005	0.063	0.048	0.071	0.073	0.077	0.077
2030	0.080	0.018	0.033	0.010	0.009	0.005	0.005	0.062	0.047	0.070	0.071	0.076	0.076
2031	0.079	0.018	0.032	0.010	0.009	0.005	0.005	0.061	0.046	0.069	0.070	0.074	0.074
2032	0.078	0.018	0.032	0.010	0.009	0.005	0.004	0.060	0.046	0.067	0.069	0.073	0.073
2033	0.076	0.017	0.031	0.010	0.009	0.004	0.004	0.059	0.045	0.066	0.068	0.072	0.072
2034	0.075	0.017	0.031	0.010	0.009	0.004	0.004	0.058	0.044	0.065	0.067	0.071	0.071
2035	0.074	0.017	0.030	0.010	0.008	0.004	0.004	0.057	0.043	0.064	0.065	0.070	0.070
2036	0.073	0.017	0.030	0.009	0.008	0.004	0.004	0.056	0.043	0.064	0.065	0.069	0.069
2037	0.072	0.016	0.030	0.009	0.008	0.004	0.004	0.056	0.042	0.063	0.064	0.068	0.068
2038	0.071	0.016	0.029	0.009	0.008	0.004	0.004	0.055	0.042	0.062	0.063	0.067	0.067
2039	0.070	0.016	0.029	0.009	0.008	0.004	0.004	0.054	0.041	0.061	0.062	0.066	0.066
2040	0.069	0.016	0.029	0.009	0.008	0.004	0.004	0.054	0.041	0.060	0.061	0.065	0.065
2041	0.069	0.016	0.028	0.009	0.008	0.004	0.004	0.053	0.040	0.060	0.061	0.065	0.065
2042	0.068	0.016	0.028	0.009	0.008	0.004	0.004	0.053	0.040	0.059	0.060	0.064	0.064
2043	0.067	0.015	0.028	0.009	0.008	0.004	0.004	0.052	0.040	0.059	0.060	0.063	0.063
2044	0.067	0.015	0.028	0.009	0.008	0.004	0.004	0.052	0.039	0.058	0.059	0.063	0.063
2045	0.066	0.015	0.027	0.009	0.008	0.004	0.004	0.051	0.039	0.058	0.059	0.062	0.062
2045	0.066	0.015	0.027	0.009	0.008	0.004	0.004	0.051	0.039	0.057	0.058	0.062	0.062
2047	0.066	0.015	0.027	0.009	0.008	0.004	0.004	0.051	0.039	0.057	0.058	0.062	0.062
2048	0.066	0.015	0.027	0.008	0.007	0.004	0.004	0.051	0.039	0.057	0.058	0.062	0.062
2049	0.065	0.015	0.027	0.008	0.007	0.004	0.004	0.051	0.038	0.057	0.058	0.062	0.062
2050	0.065	0.015	0.027	0.008	0.007	0.004	0.004	0.050	0.038	0.057	0.058	0.061	0.062
15-year levelized	0.080	0.018	0.033	0.010	0.009	0.005	0.005	0.062	0.047	0.070	0.071	0.076	0.076

Note: Values differ across states because states vary in terms of size of oil consumption.

[328] 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 U.S.-wide DRIPE value of $2.25 per MMBtu.

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 2024 is worth $0.096 per MMBtu and a reduction in 2028 is worth $0.083 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 126 by the refined-price to crude-price ratio found in Table 127. For example, the levelized value of gasoline DRIPE across New England is worth $0.1454 per MMBtu reduced ($0.084 per MMBtu x 1.51).

Table 127. AEO 2023 prices of crude oil and refined petroleum products

Product	2023–2035 Avg Price (2022 $ per gallon)	Ratio of product price to WTI price
WTI Crude Oil	2.49	-
Home heating oil	4.15	1.67
Residual fuel oil	2.40	0.96
Motor gasoline	3.75	1.51
Motor diesel	4.58	1.84

Source: EIA AEO 2023 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 128 illustrates the differences between crude oil DRIPE calculated in AESC 2021 and AESC 2024. In AESC 2024, oil DRIPE values for New England as a whole are 9 percent higher than in the previous study. This change is primarily due to increases in forecasts of crude oil prices.

Table 128. Comparison of oil DRIPE values (2024 dollars per MMBtu)

	New England	CT	MA	ME	NH	RI	VT
AESC 2021	0.074	0.017	0.031	0.010	0.008	0.004	0.004
AESC 2024	0.080	0.018	0.033	0.010	0.009	0.005	0.005
Difference ($)	0.007	0.002	0.002	0.001	0.001	0.000	0.000
Difference (%)	9%	11%	8%	7%	13%	9%	10%

Note: Values shown are levelized over 15 years. AESC 2021 uses a discount rate of 0.81 percent while AESC 2024 values use a discount rate of 1.74 percent.

Schedule MM-R1

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.[329] This chapter describes a methodological approach that program administrators can use to estimate avoidable T&D costs for planning and reporting of efficiency program benefits. It also quantifies avoided costs related to pool transmission facilities (PTF) transmission based on forward-going investments and identifies methodologies that could be used for estimating other categories of avoided T&D, including local T&D.

We estimate an avoided PTF cost of $69 per kW-year. For AESC 2024, we updated this value based on a recent ISO New England study that estimates future transmission investments through to 2050. AESC 2021 estimated a PTF avoided cost of $84 per kW-year in 2021 dollars ($95 per kW-year in 2024 dollars). We derived this value from the AESC 2018 avoided PTF value by applying an adjustment factor which represented the difference in future T&D spending relative to historical investments.

The Synapse Team 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, as part of AESC 2018. The common evaluation rubric was updated in 2021 and is again presented in AESC 2024. It includes:

1. 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.
2. Reviewing utility approaches to calculating geographically localized avoided costs, such as for NWAs.
3. 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 studies examine 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 2024 addresses 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.

[329] 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.

Schedule MM-R1

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 regionwide PTF avoided costs. 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 2021, 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 MW.[330]
- 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 O&M 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 about the cost and timing of the specific project to be avoided and the amount of load reduction

[330] 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.

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).[331]

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 projects used in the analysis are not usually avoided.

Depending on the amount of excess capacity on the various levels of T&D equipment in a particular area, reducing load by any particular customer may 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.[332]

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 relevant for T&D 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

[331] 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.

[332] 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.

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 use 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: *Survey of utility avoided costs for non-PTF transmission and distribution*).

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 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.[333]

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:

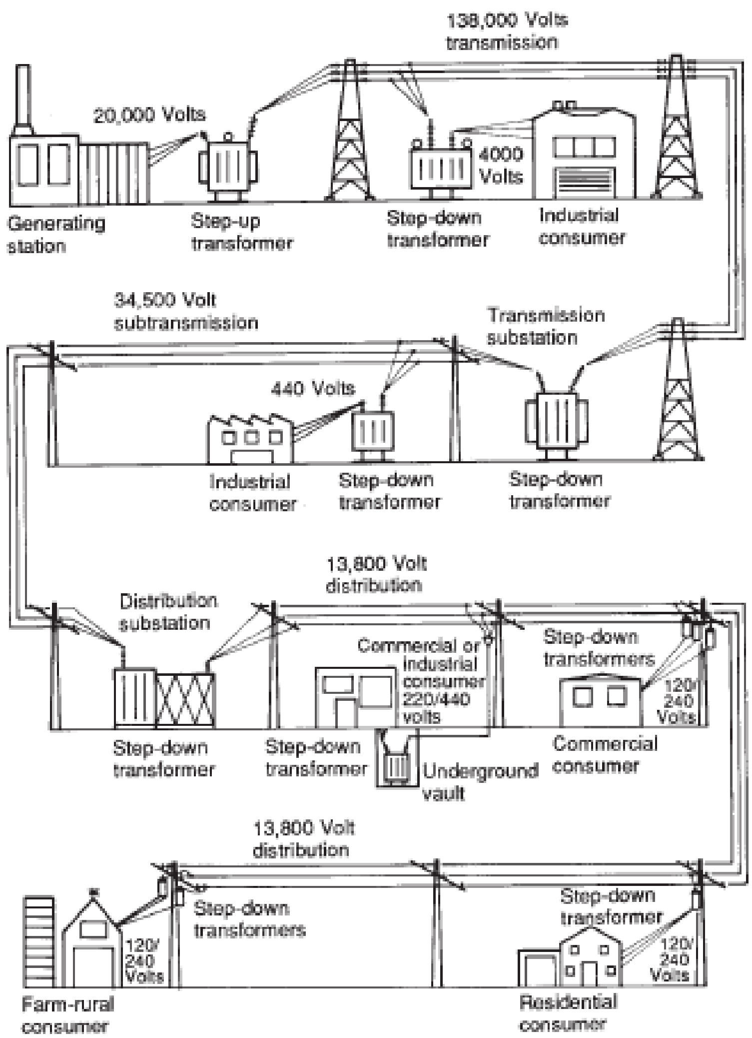
- high-voltage transmission lines (115 kV to 345 kV);
- transmission substations connecting transmission lines at different voltages;
- sub-transmission lines (e.g., 69 kV) that connect to distribution substations and some very large customers;
- bulk distribution substations that step transmission voltages down to generally high distribution voltages (mostly at 13.8 kV to 25 kV);
- high-voltage primary feeders that distribute power from the bulk substations to lower-voltage substations, some primary-voltage customers, and line transformers;

[333] 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.

- 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 58 illustrates the general design of T&D systems. The range of voltages considered to be sub-transmission varies among utility systems.

Figure 58. Schematic of a T&D system



Source: Electric Power Generation, Transmission and Distribution eTool. U.S. Department of Labor. Available at https://www.osha.gov/SLTC/etools/electric_power/illustrated_glossary/.

Schedule MM-R1

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 use 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 designed 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.[334] 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.

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[334] Something must use more energy at the extreme peak, or it would not be an extreme peak.

Schedule MM-R1

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 studies recommend using top-down accounting analyses to identify the accounts that are primarily load-related[335] and net out an allowance for the costs of replacing retired equipment in kind. The FERC Form 1 data include both additions and retirements by account. Bottom-up analyses should be used to identify the projects and blanket accounts that are primarily load-related.[336]

For the bottom-up analyses, we recognize 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.[337]
- 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.[338]
- 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 investment is load-related.

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335 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 here is based on identifying load-related investments using current distribution system planning practices.

336 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.

337 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.

338 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.

In contrast, other investments are clearly required to accommodate load growth, including:

- Most new transmission lines and substations and additional transformers at existing substations;
- Additional feeders and line transformers in areas with existing service;
- Reconductoring of lines to increase capacity;
- Increasing the voltage of transmission or distribution lines; and
- Conversion of single-phase feeder branches to two-phase or three-phase operation.

A third set of investments is harder to characterize, including such situations as:

- Investments triggered by factors other than load, but whose cost 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.[339]
- 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.

[339] 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.

Schedule MM-R1

- Investment driven by load-related energy considerations, including transmission congestion relief and reduction of line losses.[340]

AESC studies recognize 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 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 MW at the transmission level, at the distribution level, or at the meter.[341] 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.[342]

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[340] Line losses should be computed on a marginal basis, where possible.

[341] 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).

[342] 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.

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 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 ($kW_{end\text{-}use}$) the calculation would understate the value of efficiency by a ratio of $kW_{hardware}$ per $kW_{end\text{-}use}$. 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 $kW_{end\text{-}use}$-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 $kW_{end\text{-}use}$ 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

Schedule MM-R1

that has experienced growth.[343] Counterfactual 1 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 a distribution plant, the analysis should use a lower carrying charge for transmission than distribution. This is one reason that avoided transmission and distribution are usually computed separately.

The carrying charge should be computed in $/kW-year levelized in real terms. The real-levelized carrying charge is the first-year charge that, if escalated at the inflation rate, will have the same present value as the revenue requirements for the project or the nominally levelized charge. The real-levelized carrying charge in each year represents the present value benefit of a one-year delay in 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.[344] 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.

[343] 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.

[344] "Gross plant" is defined as the total capital assets dedicated to utility service and is used to determine rate base.

In addition to avoiding new facilities and their O&M, lower loads will also tend to reduce the rate of failures of existing equipment and thus the capital and O&M costs involved in repairing and replacing the damaged equipment.

Overheads

Utilities generally allocate a range of overhead or administrative costs (e.g., senior management, legal, financial, human resources, purchasing and contracting, information technology, warehousing, office expense, vehicles) on labor or a similar broad measure of O&M and construction costs. Some of those overheads may not vary linearly with the number of personnel required to design, build, maintain and operate the assets, but increased construction will generally require more of the overheads as a whole.

The utility's overhead adders should be included in both the load-related investments and the associated O&M. Any exclusion of overhead costs from avoided T&D investment should be carefully considered and fully justified.

10.2. Avoided pool transmission facilities cost

All load in New England pays for PTFs. These costs are in addition to those that individual utilities pay to local facilities in the local networks. We rely on ISO New England research and analysis to estimate these avoided PTF costs.

In November 2023, ISO New England published its *2050 Transmission Study*, a first-of-its-kind long-term study that estimates transmission system investments needed by 2050 to ensure a reliable and smooth clean energy transition.[345] The study incorporates New England's likely future resource mix and increasing demand associated with building and transportation electrification. The study outlines a range of investment costs for expected future peak loads in 2035, 2040, and 2050.[346]

The study estimates total investment costs to provide reliable transmission in 2050 will range from $16 billion to $17 billion (in 2024 dollars) and assumes that roughly 80 to 85 percent of buildings are electrified, energy efficiency programs are in place, and 100 percent of transportation is electric by the middle of the century.[347] These costs estimates are primarily load-related costs; the study did not include interconnection upgrade costs as well as the cost of upgrades related to voltage performance, transient stability performance, and short-circuit performance.

[345] ISO New England Inc. November 21, 2023. DRAFT 2050 Transmission Study. Available at: https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies.

[346] ISO New England's *2050 Transmission Study* serves as a roadmap to identify transmission needs beyond the current 10-year planning horizon and is designed to show generally how future transmission-related objectives can be accomplished over the next few decades. The Study is not intended as comprehensive or detailed plans for construction. Nonetheless, it estimates a range of likely future costs associated with upgrading the transmission system.

[347] ISO New England's *2050 Transmission Study* also estimates transmission costs future a 2050 peak with 100 percent building and transportation electrification. For this scenario, costs range from $24 to $27 billion dollars (in 2024 dollars).

The *2050 Transmission Study* predicts the transmission system will transition to a winter peaking system around 2035, with a 2020 annual peak of 51 GW (this is similar to the peak loads observed in the counterfactuals modeled in AESC 2024 that are inclusive of building electrification measures, such as Counterfactual #5). Based on the highest load observed on the New England system to date, seen in the summer of 2006, the region is expected to see total peak load growth of 23 GW by 2050. Dividing the load-related costs by the load growth driving these investments results in an expected range of $711 per kW to $756 per kW by 2050. Taking a mid-range value, this results in investment costs of $734 per kW.

We convert this investment value to an annual avoided cost value that incorporates depreciation of costs overtime and utility revenue requirements charged to ratepayers. To do this, we use a “carrying charge rate,” a percentage we multiply by total costs to estimate the annual revenue requirement of an investment. For AESC 2024, we determine an average carrying charge rate of 9.4 percent. We assume a 50/50 debt-to-equity financing ratio, debt and equity rates of 4.5 percent and 10 percent, respectively, effective state and federal tax rate of 27 percent, and a 45-year transmission line life (consistent with previous AESC studies). We average the O&M expenses, property taxes, and insurance expenses across the three carrying charge calculations from Eversource and National Grid (provided in the 2018 T&D survey): property taxes total roughly 2 percent, insurance expenses represent less than 1 percent, and O&M expenses are roughly 1 percent. We multiply the average carrying charge rate by the value of investment ($/kW) to get a dollar per kW-year avoided cost value. The annualized avoided cost is thus $734 per kW times 9.4 percent, or $69 per kW-year (2024 dollars).

Using avoided PTF values

Avoided and deferred PTF costs

An “avoided cost” of $69 per kW-year also represents the present value benefit of a one-year delay in making the PTF investment, or in other words, the cost of deferring the PTF investment by one year as a result of a one-year reduction in peak load. This is due to the treatment of the carrying charge rate within the calculation of the avoided PTF value. 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 total costs expected to be incurred due to load growth.

Annual system peaks

Regional transmission needs related to load growth have typically been driven by summer peak loads. In its long-term transmission planning study, the ISO New England predicts that with electrification, the region’s transmission system will shift to a winter peaking system by 2035. Similarly, all of AESC’s counterfactuals scenarios have some level of electrification (all incorporate transportation electrification while many incorporate both building and transportation electrification). All counterfactuals have winter peaks that approach, or even exceed, the summer peaks in the mid-2030s or early 2040s. Regardless of whether the system peaks in the winter or the summer, the transmission system is built to reliably meet the total system peak, each year. Therefore, when evaluating measures, program administrators should apply this regional PTF value to a measure’s impact on the regional annual system peak, regardless of when the peak occurs. Reducing annual peak load through DERs will avoid or defer future upgrades to the transmission system, which is built to meet that annual peak.

Counterfactual scenarios

In its long-term transmission planning study, the ISO New England estimates transmission system needs in a future with high levels of electrification, energy efficiency, and significantly more renewable energy on the electric grid. It also estimates costs in a future with 100 percent building and transportation electrification by 2050. It does not, however, estimate future transmission investments for a future with no building electrification and no energy efficiency programs, such as AESC Counterfactual 1. ISO New England's *2050 Transmission Study* is the only ISO-led study to date that attempts to holistically estimate long-term transmission requirements in New England. Furthermore, it includes transportation electrification, an element that is maintained across all AESC counterfactuals. It also assumes a winter peaking system within the next decade; all AESC counterfactuals have winter peaks that approach (or exceed) the summer peaks in the 2030s or 2040s. Without access to studies or information on potential transmission costs for a New England future without any additional DER measures, the ISO study serves as the best available source of data for this avoided cost category. As such, the avoided PTF value of $69 per kW-year should be applied to annual peak reductions in all counterfactual scenarios.

Comparison of avoided PTF across years

Table 129 shows a comparison of each AESC avoided PTF value.

Table 129. Comparison of avoided PTF costs

Study	Avoided Costs (2024 $/kW-year)	Method
AESC 2018	$112	Historical data
AESC 2021	$95	Historical data (scaled to forward-looking PTF investments)
AESC 2024	$69	Long-term forward-looking data

AESC 2018 calculated avoided PTF costs on a historical basis, using then-current Transmission Cost Allocation (TCA) data to identify load-related investments in substations, new lines, voltage upgrades, and additional capacitors and transformers for projects for 2003 through 2024, and load projections for that period. AESC 2018 estimated avoided PTF cost as $94 per kW-year in 2018 dollars (equal to $112 per kW-year in 2024 dollars).

After the completion of AESC 2018, several stakeholders raised concerns that the analysis was backward-looking rather than prospective, so we updated AESC 2021 estimates to be forward-looking. We reviewed projects in the October 2020 Draft RSP Project List, which included projects planned through 2026. However, at that time, ISO New England peak loads were declining, due in part to the energy efficiency programs. Additionally, the RSP Project List lacked data on the amount of past and projected load growth driving these transmission expansion plans (despite loads in some areas growing that were driving the load-related RSP projects). As a result, in AESC 2021, we estimated avoided PTF costs using the historical-looking AESC 2018 avoided cost estimate, scaling it by the share of forward PTF investments relative the historical PTF investments used in the AESC 2018 calculations. Specifically, RSP forward-looking costs were 85 percent of the historical TCA costs on an annualized basis, so we scaled the AESC 2018 avoided PTF costs by 85 percent to provide the estimate of $84 per kW-year ($94/kW year in 2024 dollars).

The AESC 2024 calculation is entirely forward-looking and based on the recent ISO New England study on long-term transmission needs for a reliable and smooth energy transition.

Avoided PTF transmission costs and their relationship to Regional and Local Network Service

The avoided PTF costs derived in this section reflect avoidable future costs. As PTFs are built, the costs of those facilities are recovered through ISO New England's Regional Network Service (RNS) charge. RNS is recovered across the whole region, dictated by a formula that includes aggregate PTF revenue requirements and the monthly peak loads in each load zone. Local network service (LNS) charges are used to recover the cost of local transmission assets (rather than PTFs).

The avoided PTF costs presented in this section do not include any impact of changes in the cost or cost allocation of already-built regional transmission facilities. The cost of these facilities is unavoidable, from a regional perspective, because transmission owners need to recover the cost of their past investments.

Reducing peak load on the bulk system has two effects: (1) it reduces the need to build more transmission, or defers future PTF investments, thus keeping future RNS costs lower; and (2) it shifts some of the existing RNS costs to others in the region who have not reduced their peaks by the same proportion. LNS costs for existing non-PTF transmission cannot be shifted to ratepayers in other areas, so only the first effect would exist for local avoided transmission value.

How one treats these two effects depends on one's cost-effectiveness test:

- When using a cost-effectiveness test that takes a regional perspective to transmission costs, the entirety of the avoided PTF cost would be included. No savings are possible for sunk transmission costs reflected in today's RNS rates. (That is, the second effect of reducing peak load identified above would cause a transfer within the region, rather than an avoided cost.)
- When using a cost-effectiveness test that takes a state-level perspective, only a portion of the avoided PTF cost would accrue to the benefit of the ratepayers within the state implementing the programs. As a result, the avoided PTF cost would be scaled down based on the state's share of RNS costs. At the same time, there would be some additional value to that state's ratepayers from shifting embedded RNS costs to ratepayers in other states, relative to the counterfactual in which other states operate programs but the state in question does not. Furthermore, load reductions at the annual peak reduce PTF investments, while the cost allocation of RNS depends on monthly peak loads. In theory, a state could reduce shoulder-season monthly peaks more so than other states but makes no impact on the annual peak driving the PTF spending. Since RNS is based on contributions to monthly peaks, this state's share of RNS costs could decrease relative to other states, despite doing little to reduce PTF investments. AESC 2024 does not model the state-level counterfactuals that would be required to quantify

Schedule MM-R1

a state-level avoided RNS value, nor does it quantify the monthly zonal peak values used in the RNS tariff.

Low load considerations

Localized loads significantly below system averages can result in various issues for the transmission system, including disturbances to voltage levels due to back feed from the distribution system. Historically, load growth has driven a large amount of pooled transmission projects in New England. However, in recent years, increasing amounts of distributed generation and other DERs have resulted in low loads on the transmission system at certain times of the year. ISO New England is now beginning to develop projects that address these low load conditions, which account for 3 percent, or $7.9 million (in 2024 dollars), of its planned and proposed PTF projects.[348] These types of investments may grow as more DERs are added to the system in the short to medium term. At the same time, their effect may be muted or eventually avoided altogether as New England adds load due to electrification.

AESC's avoided PTF cost is the value of avoiding or deferring projects associated with load growth. It represents the benefit of peak period load reductions from energy efficiency or other DERs. Conversely, low-load-related transmission projects are costs to the system that result from load reductions in certain areas or at certain times of the year. Since ISO New England does not currently publish forecasted load minimums, and there is limited information available on how low load will affect transmission costs in New England, we could not estimate a low-load PTF cost for AESC 2024. In future years, when more information on low-load projects is available, we can more explicitly incorporate low-load-related costs into AESC, which could inform a cost adder to apply to projects that reduce load at times not beneficial to the transmission grid.

10.3. Survey of utility avoided costs for non-PTF transmission and distribution

AESC 2021 included 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). The AESC 2024 Study Group members agreed that the information collected and evaluated in AESC 2018 and 2021 had not changed enough to warrant a new survey or evaluation of utility's non-PTF avoided cost approaches.

The non-PTF avoided T&D 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);

[348] This includes all in-service, under construction, planned, and proposed projects from 2021-2024. Regional system Plan and Related Analyses, ISO New England and Final RSP Project List – June 2023. Available at https://www.iso-ne.com/system-planning/system-plans-studies/rsp.

Schedule MM-R1

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);
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 section 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 130 summarizes the avoided T&D values currently in use. Table 131 provides a summary of the load forecast methodologies used in developing these avoided T&D cost values. Table 132 provides more detailed methodological considerations used in deriving the avoided cost values.

Schedule MM-R1

Table 130. Summary of utility avoided T&D cost methodologies[349]

Criterion	Eversource			National Grid		UI	Vermont	Maine	Unitil
	CT	*MA*	*NH*	*MA*	*RI*	*CT*	*VT*	*ME*	*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.

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[349] In 2022 after the completion of this survey, PPL Corporation acquired National Grid's Rhode Island service, which is now Rhode Island Energy.

Schedule MM-R1

Table 131. Avoided T&D load forecast methodologies[350]

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. As of 2022, Rhode Island's National Grid's service territory is now served by Rhode Island Energy.

[350] In 2022 after the completion of this survey, PPL Corporation acquired National Grid's Rhode Island service, which is now Rhode Island Energy.

Table 132. Detailed considerations for calculation of load-specific avoided T&D costs[351]

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 T&D costs	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 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

351 In 2022 after the completion of this survey, PPL Corporation acquired National Grid's Rhode Island service, which is now Rhode Island Energy.

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.[352] 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.[353] 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.[354]

Table 133 summarizes the distribution methodology employed by National Grid, as well as recommendations for improvement.

[352] In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

[353] The Narragansett Electric Company d/b/a National Grid. Docket No. 5076 - 2021 Annual Plan. Attachment 4.

[354] The analysis in this section is based on National Grid MA and RI - 2018 Avoided T&D Workbooks,

Schedule MM-R1

Table 133. 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 energy efficiency measures but does not include the impact of forecasted energy efficiency adoption.	National Grid should use a load forecast that includes future projected energy efficiency savings since the investment forecast assumes continued energy efficiency 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.[355] 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

Schedule MM-R1

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 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 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 134 summarizes the distribution methodology employed by United Illuminating, as well as recommendations for improvement.

Table 134. 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	UI used a weighting construct where 20% of its 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.

355 United Illuminating, Avoided Transmission and Distribution Cost Study 2000–2006.

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
		program and its applicability to other programs should be evaluated and updated accordingly.	
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 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 this in forecasted CLM adoption. This methodology is accurate in quantifying the infrastructure costs that would be required without CLM provided that the investments and capital expenditure estimates also reflect growth	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-growth-related investments, for an avoided T&D study we recommend dividing these investments by the growth in peak demand during the timeframe identified as opposed to the load-serving	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.

Schedule MM-R1

Topic	Overall Assessment	Recommendations for Improvement	Recommendations on Clarity
	without CLM included for consistency.	capacity of the 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

Schedule MM-R1

investments on the T&D system.[356] 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. Eversource does not consider these historical T&D investments that are related to customer growth avoidable/deferrable and therefore removed them from the analysis. Eversource used results of the regressions to evaluate the percentage of the T&D 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 135 summarizes the distribution methodology employed by Eversource, as well as recommendations for improvement.

Table 135. Assessment of Eversource's avoided distribution methodology and recommendations for improvement

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
Overall T&D Methodologies	Eversource's methodology 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&D 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	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.

[356] 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.

Schedule MM-R1

Topic	Overall Assessment	Recommendations on Improvement	Recommendations on Clarity
		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.	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.
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.

Schedule MM-R1

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 because 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 136 summarizes the distribution methodology employed in Vermont, as well as recommendations for improvement.

Schedule MM-R1

Table 136. 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 regionwide 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	Vermont Electric Power Company 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 used 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.[357] The developed avoided T&D 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.

[357] 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.

Schedule MM-R1

In calculating the distribution expenditures, CMP uses forecasted load at the level of the service center as part of Chapter 330 filings.[358] 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 of 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 AESC 2024 Study Group members agreed that the information presented here was up to date. The section surveys the landscape of location-specific avoided T&D methods and approaches in the region.[359]

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
3. Calculate avoided cost ($/kW) based on the present value of deferred expenditures and the required load reduction

[358] 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).

[359] 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

Schedule MM-R1

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 utilities' 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.[360] 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.

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

[360] The load forecast should be the same for evaluating NWAs and traditional engineering solutions.

Schedule MM-R1

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.[361] 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 to 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.[362] 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.

In addition, the severity and nature of the overload (e.g., the contingency number) are considerations 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.

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361 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.

362 CYME. Last Accessed March 10, 2021. "CYME International" *Cyme.com.* Available at http://www.cyme.com/

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.[363]

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.[364]

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.[365] 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 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).

[363] As the availability and granularity of data improves through technologies and planning advancements, we anticipate improvements in methodology and applicability to more feeders.

[364] This methodology does not comment on the accessibility of detailed load, engineering, and cost data for feeders and components.

[365] 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.

Schedule MM-R1

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, AESC 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) 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:[366]

$$RCC = WACC + Income\ Tax + Property\ Tax + Insurance + O\&M$$

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

[366] 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.

Schedule MM-R1

discounted by the real discount rate.[367] 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.[368] 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. 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 included a rubric, developed 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

[367] 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.

[368] This methodology does not address issues regarding operational control or visibility associated with the T&D system.

Schedule MM-R1

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. The AESC 2024 Study Group members agreed that the information collected and evaluated in AESC 2018 and 2021 had not changed enough to warrant a new survey or evaluation of current utility methods.

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 137 provides a general summary of methodologies related to identification of candidate locations for NWAs and the related load forecast methodologies. Table 138 provides specific criteria/thresholds for selection of a locations as an NWA. Table 139 and Table 140 provide a summary of specific design/engineering criteria applied at the T&D level.

Table 137. Summary of location-specific evaluation methodologies and load forecast processes[369]

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 is 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.

369 In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

Schedule MM-R1

Table 138. Summary of processes for identifying locations that would benefit from load reductions[370]

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

[370] In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

Table 139. Summary of processes for identifying target locations that would benefit from load reductions at the transmission level[371]

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	NERC, 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
Whether hybrid NWA solutions are 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

[371] In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

Schedule MM-R1

Table 140. Summary of processes for identifying target locations that would benefit from load reductions at the distribution level[372]

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
Whether hybrid NWA solutions are 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%

372 In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

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 sub-transmission capital projects and system needs.[373] National Grid identifies system needs as a result of studies, operational issues, process safety issues, occupational safety issues, regulatory requirements, and/or customer requests.[374] 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 141 below.

Table 141. National Grid NWA screening criteria[375]

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 net-present-value 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 142 summarizes the NWA methodology employed by National Grid, as well as recommendations for improvement.

[373] In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

[374] National Grid. Guidelines for Consideration of Non-Wires Alternatives in Distribution Planning. March 2020.

[375] In 2022, after the completion of this survey, National Grid's Rhode Island service was acquired by PPL Corporation, and is now Rhode Island Energy.

Schedule MM-R1

Table 142. 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.[376] 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 into 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.

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

[376] Survey To Evaluate Program Administrators Avoided T&D methodologies. Responses received on November 16, 2020.

Schedule MM-R1

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:[377]

- 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 a 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:[378]

- 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
- Eversource SYSPLAN-01—Eversource Energy Transmission System Reliability Standards

[377] 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.

[378] 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

Specific transmission suitability criteria for Non-Transmission Alternatives (NTA) 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.[379]

Table 143 summarizes the NWA/NTA methodology employed by Eversource, as well as recommendations for improvement.

Table 143. 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 NWAs 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 suitable to NWA consideration including cost threshold, timeline, and the quantity of load reduction required.	-	-

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

379 "Non-Transmission Alternative" is the terminology used by Eversource in referring to NWAs at a transmission level.

Schedule MM-R1

transformers, stepdown transformers protective devices, and other distribution circuit elements.[380] In addition, at the transmission and distribution levels, Until reviews NWA projects 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.[381] The company indicated that the 80 percent threshold accounts for lead times needed to implement NWA solutions.[382] Unitil assumes a minimum of three years to receive, evaluate, and implement NWA proposals.[383] In addition, Unitil typically considers NWAs to be suitable in addressing loading and/or voltage constraints but not suitable for condition-based replacement projects.[384] 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.[385]

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 is split into two phases.

Transmission-Level Process

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 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 NTAs.

[380] Unitil. Distribution Planning Guide. November 19, 2019. Page 8.

[381] Id. Page 8.

[382] Id. Section 4.3.

[383] Unitil. Project Evaluation Procedure, Page 3, July 2018.

[384] Unitil. Project Evaluation Procedure, Page 4, July 2018.

[385] Unitil. Project Evaluation Procedure, Page 3, July 2018.

Schedule MM-R1

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 considers bulk/predominantly bulk transmission-level constraints once an LRTP is published, as described above.

Utilities typically identify distribution constraints in their IRPs or at any time in intervening years 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 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 (because customers would reduce the use of renewable generation on-site) or require increased investments to ensure reliability. While this issue is currently limited to a small number of hours, it is anticipated to worsen over the next decade as more renewable energy comes online to meet Vermont's clean energy goals.

Table 144 summarizes the NWA methodology employed by Vermont, as well as recommendations for improvement.

Schedule MM-R1

Table 144. 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*.[386] 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 to appear in New England, including several locations in Vermont at both the transmission[387] and distribution[388] levels.

[386] 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.

[387] 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.

[388] 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

Schedule MM-R1

As part of its interconnection process, each generator is generally asked to pay for incremental changes in the grid that are required 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 considered. 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 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.

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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.

Schedule MM-R1

11. VALUE OF 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 reduces failures. Third, 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 new 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 2024, we find a default average VoLL value of $61 per kWh. This value is about 26 percent less than the value derived in AESC 2021 ($82 per kWh in 2024 dollars). The change in the VoLL component is a result of specifying the value to the New England states. We apply this VoLL 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 2024, we find 15-year levelized values of $0.38 per kW-year for cleared benefits and $4.82 per kW-year for uncleared benefits. These are 25 to 50 percent lower than the same values estimated in AESC 2021, after adjusting for inflation. The primary differences for these changes include a reduction in the assumed VoLL (as described above) and different input parameters related to the capacity market supply and demand curves.

As in AESC 2021, we also provide an estimated benefit for T&D reliability, based on data for National Grid Massachusetts. This section provides 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.* In AESC 2021, we used the analysis found in AESC 2018 and a 2018 study from Europe written by Cambridge Policy Associates to determine a VoLL value of $82 per kWh (in 2024 dollars). For AESC 2024, we review the recent literature on VoLL, looking for values more relevant to New England.

Schedule MM-R1

In our updated literature review, we identify an Interruption Cost Estimate (ICE) Calculator funded by the U.S. Department of Energy and developed by LBNL and Nexant, Inc.[389] The meta-analysis and econometrics models used in the ICE Calculator are documented in the LBNL 2015 study that was used to inform the AESC 2018 and 2021 VoLL values. The ICE Calculator allows the user to specify the state(s), number of residential and non-residential customers, and two of the three index values used to measure reliability for a given area of interest. For AESC 2024, we chose to use the ICE Calculator to determine the VoLL because it allow us to enter specific inputs relevant to New England, thus allowing us to estimate a VoLL specific to New England.[390]

The ICE Calculator provides a Cost of Unserved kWh value for the residential, small C&I, and large C&I customer classes, in the states selected by the users. Users must also specify a set of other inputs into the model. First, the ICE Calculator requires users to enter values for two measures of reliability: System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).[391] SAIFI is the number of times in a year the average customer experiences an interruption. SAIDI is the total number of minutes in a year the average customer experiences an interruption. These values vary over time. For the ICE Calculator, we average the SAIDI and SAIFI values provided by EIA from 2013 to 2021 (see Table 145).[392] EIA provides SAIDI and SAIFI values including Major Event Days and excluding Major Event Days. A Major Event Day is any day that exceeds a daily SAIDI threshold, as defined by the Institute of Electrical and Electronics Engineers (IEEE) 1366 guide.[393] The IEEE 1366 also defines the SAIDI, SAIFI, and CAIDI reliability metrics and is the industry standard. We include Major Event Days in our SAIDI and SAIFI averages. We determine the number of residential and non-residential customers in New England by averaging the number of customers in New England from 2018 to 2022 using EIA's form 861.[394] We also make an adjustment to the following two assumptions made by the ICE Calculator to be consistent with our inputs: the total number of customers in each customer class and the weighted average annual usage per customer of each customer class using values from EIA's Form

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[389] Sullivan, M., et al. July 2018. *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities*. Lawrence Berkeley National Lab (LBNL). Available at https://icecalculator.com/.

[390] Note that our VoLL literature review also identified a number of other sources on the subject new to AESC. These sources generally described VoLL values for other regions or for long-duration power outages and were thus not included in the AESC 2024 calculation as they are less relevant than the ICE Calculator. These sources have been added to *Appendix I: Matrix of Reliability Sources*.

[391] We note that the ICE calculator accepts any two of the three reliability measures: SAIDI, SAIFI, and Customer Average Interruption Duration Index (CAIDI, or the average number of minutes an interruption lasts. It is calculated from dividing the SAIDI by the SAIFI). For the development of VoLL in AESC 2024, we have only populated the SAIDI and SAIFI parameters, and have ignored CAIDI.

[392] For historical SAIDI and SAIFI values, see U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report. Available at https://www.eia.gov/electricity/annual/html/epa_11_04.html and U.S. Energy Information Administration, Form EIA-861, Annual Electric Power Industry Report. Available at https://www.eia.gov/electricity/annual/html/epa_11_05.html.

[393] "IEEE Guide for Electric Power Distribution Reliability Indices," in *IEEE Std 1366-2022 (Revision of IEEE Std 1366-2012)* , vol., no., pp.1-44, 22 Nov. 2022, doi: 10.1109/IEEESTD.2022.9955492.

[394] U.S. Energy Information Administration, Form EIA-861. Available at https://www.eia.gov/electricity/data/eia861/.

Schedule MM-R1

861.[395] Synapse performed these edits in the Interruption Costs Spreadsheet provided in the documentation of the ICE Calculator.[396] Using share-of-sales data from EIA's Form 861 and the ICE Calculator outputs, we calculated a weighted average (see Table 146).

Table 145. ICE calculator inputs

Input	Average from 2013 to 2021 in New England
SAIDI (minutes per year)	515.0
SAIFI (times per year)	1.489
Number of residential customers	8,233,989
Number of non-residential customers	1,293,086

Table 146. Calculation of VoLL

	VoLL estimated by ICE Calculator (2024 $/kWh)	Sale shares %
Residential	$2.86	40%
Small C&I	$103.42	45%
Large C&I	$91.77	14%
Weighted Average VoLL	$61	

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 calculate this component for cleared measures and uncleared measures.

[395] Ibid.

[396] Sullivan, M., et al. July 2018. *Estimating Power System Interruption Costs: A Guidebook for Electric Utilities*. Lawrence Berkeley National Lab (LBNL). Available at https://icecalculator.com/documentation.

Schedule MM-R1

Calculating cleared reliability

In order to calculate cleared reliability benefits, we first assemble several input parameters. First, ISO New England annually publishes MRI curves, which estimate the expected unserved energy avoided per MW of additional supply as the reserve margin rises. In AESC 2024, 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 unserved energy per MW of reserve. Values calculated in FCA 15 through 18 utilize the MRI curve published for each auction. Values calculated in FCA 19 and after are similarly calculated based on the future-year MRI curves that set the demand for capacity in EnCompass. Table 147 displays the estimated change in MWh of reliability benefits per MW of reserve, and how it varies with the capacity market clearing price.

Table 147. Change in MWh of reliability benefits per MW of reserve for Counterfactual #1 in Rest-of-Pool region

		Clearing price *2024 $/kW-month*	Δ MWh LOEE per MW *MWh / MW*
FCA 15	2024	$2.66	0.17
FCA 16	2025	$2.53	0.26
FCA 17	2026	$2.48	0.27
FCA 18	2027	$2.48	0.22
FCA 19	2028	$1.42	0.13
FCA 20	2029	$1.38	0.13
FCA 21	2030	$1.42	0.13
FCA 22	2031	$1.42	0.13
FCA 23	2032	$4.25	0.39
FCA 24	2033	$4.25	0.39
FCA 25	2034	$5.66	0.51
FCA 26	2035	$7.08	0.64
FCA 27	2036	$5.66	0.51
FCA 28	2037	$7.08	0.64
FCA 29	2038	$7.08	0.64

Note: Values for other counterfactuals and regions can be found in the AESC 2024 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 148). We calculate this value 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.

Schedule MM-R1

Table 148. Net increase in cleared supply for Counterfactual #1 in Rest-of-Pool region

		Clearing price	Net increase in cleared supply
		2024 $/kW-month	*%*
FCA 15	2024	$2.66	47%
FCA 16	2025	$2.53	0%
FCA 17	2026	$2.48	0%
FCA 18	2027	$2.48	0%
FCA 19	2028	$1.42	0%
FCA 20	2029	$1.38	0%
FCA 21	2030	$1.42	1%
FCA 22	2031	$1.42	1%
FCA 23	2032	$4.25	3%
FCA 24	2033	$4.25	4%
FCA 25	2034	$5.66	3%
FCA 26	2035	$7.08	30%
FCA 27	2036	$5.66	4%
FCA 28	2037	$7.08	29%
FCA 29	2038	$7.08	30%

Note: Values for other counterfactuals and regions can be found in the AESC 2024 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 Section 9.3: *Electric capacity DRIPE*, above).

Finally, we determine the cleared reliability benefit by calculating the product of (a) the change in MWh of reliability benefits per MW of reserve, (b) the net increase in cleared supply, (c) the decay effect, and (d) the VoLL, as calculated above.[397] Table 149 describes the overall benefit for a measure installed in 2024. We note that these values are very small compared to the estimated avoided costs in many other categories.

[397] The *AESC 2024 User Interface* allows users to specify their own VoLL, if they so choose.

Schedule MM-R1

Table 149. Estimated cleared reliability benefits for Counterfactual #1 in Rest-of-Pool region for measures installed in 2024, assuming a VoLL of $72 per kWh

		Δ MWh LOEE per MW	Net Increase in Cleared supply	Decay Schedule	Cleared reliability benefits
		MWh / MW	*%*	*%*	*2024 $/kW-month*
FCA 15	2024	0.00	47%	100%	$4.94
FCA 16	2025	0.01	40%	83%	$0.03
FCA 17	2026	0.27	0%	67%	$0.00
FCA 18	2027	0.22	0%	50%	$0.00
FCA 19	2028	0.13	0%	33%	$0.04
FCA 20	2029	0.13	0%	17%	$0.02
FCA 21	2030	0.13	1%	0%	$0.00
FCA 22	2031	0.13	1%	0%	$0.00
FCA 23	2032	0.39	3%	0%	$0.00
FCA 24	2033	0.39	4%	0%	$0.00
FCA 25	2034	0.51	3%	0%	$0.00
FCA 26	2035	0.64	30%	0%	$0.00
FCA 27	2036	0.51	4%	0%	$0.00
FCA 28	2037	0.64	29%	0%	$0.00
FCA 29	2038	0.64	30%	0%	$0.00

Note: Values for other counterfactuals, regions, and resource vintages can be found in the AESC 2024 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

As with 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 MW of reserve. This parameter is the same as is used in the calculation of cleared reliability benefits (see Table 147, above).

Second, we gross up uncleared reliability benefits 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 Section 5.2: *Uncleared capacity calculations*, above, for more information on this effect.

Third, we assume reliability has a phased impact on the load forecast. In contrast to uncleared capacity and uncleared capacity DRIPE, reliability value is realized before the impact of the energy efficiency measure is felt on ISO New England's load forecast 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 capacity auction. 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.[398] Because of the switch to a prompt market in 2028, this means these effects are moved forward three years when counting benefits that accrue in 2028 and later years relative to the phase-out of reliability benefits in the market rules today, and to the same phase-out modeled in AESC 2021.

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. Under the new market structure, we assume that because the load effects start three years early (compared to the effects in the current market structure), decay is also shifted forward by three years relative to the assumption in AESC 2021.

Finally, we calculate the uncleared reliability benefit by calculating the product of (a) the change in MWh of reliability benefits per MW of reserve, (b) one plus the reserve margin, (c) the load forecast effect, (d) the decay effect, and (e) the VoLL.[399] Table 150 describes the overall benefit for a measure installed in 2024. 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—uncleared resources are invisible to the capacity market.

[398] In this regard, the reliability benefit of unclear capacity operates more like avoided energy or cleared capacity than like uncleared capacity or capacity DRIPE.

[399] Note that the *AESC 2024 User Interface* allows users to specify their own VoLL, if they so choose.

Schedule MM-R1

Table 150. Estimated uncleared reliability benefits for Counterfactual #1 in Rest-of-Pool region for measures installed in 2024, assuming a VoLL of $61 per kWh

		Δ MWh LOEE per MW *MWh / MW*	Reserve Margin *%*	Load Forecast Effect *%*	Decay Schedule *%*	Uncleared reliability benefits *2024 $/kW-year*
FCA 15	2024	0.17	14%	100%	100%	$11.85
FCA 16	2025	0.26	13%	100%	100%	$18.04
FCA 17	2026	0.27	11%	100%	100%	$18.03
FCA 18	2027	0.22	13%	100%	100%	$15.37
FCA 19	2028	0.13	5%	100%	100%	$2.24
FCA 20	2029	0.13	5%	70%	100%	$0.63
FCA 21	2030	0.13	4%	50%	95%	$0.00
FCA 22	2031	0.13	3%	30%	87%	$0.00
FCA 23	2032	0.39	1%	10%	75%	$0.00
FCA 24	2033	0.39	1%	0%	60%	$0.00
FCA 25	2034	0.51	0%	0%	43%	$0.00
FCA 26	2035	0.64	-2%	0%	27%	$0.00
FCA 27	2036	0.51	-1%	0%	0%	$0.00
FCA 28	2037	0.64	-3%	0%	0%	$0.00
FCA 29	2038	0.64	-3%	0%	0%	$0.00

Note: Values for other counterfactuals, regions, and resource vintages can be found in the AESC 2024 User Interface. The "decay schedule" series is identical for measures installed in later years, except shifted by the relevant number of years.

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 the measures reduces. 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) in high-risk hours throughout the year, under the RCA framework. 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. 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.

Schedule MM-R1

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 FCA 13), as shown in Table 151. All months other than the summer had zero risk in this analysis.

Table 151 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.[400] That may change as electrification increases winter loads and renewable and storage deployment shifts the hours at greatest risk of energy shortage.

Table 151. 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

As in 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

400 See https://www.synapse-energy.com/sites/default/files/AESC_Supplemental_Study_Part_I_Winter_Peak.pdf for more discussion on this topic.

Schedule MM-R1

- Reducing wear on lines and transformers from the cumulative effects of many hours with high loads.[401]

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 the following:

1. 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.
2. Long periods (such as many hours or days) of lower but still high loads, which heat up the insulation.
3. 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.

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.[402]

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.[403]

Example calculation

AESC 2024 repurposes the review conducted in AESC 2021. The text in the following section has not been updated since the AESC 2021 report.

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[401] Other causes (tree, weather, animal contact, etc.) of outages are not load-related and are thus outside the scope of this analysis.

[402] 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.

[403] Logically, similar considerations would apply to the reliability of natural gas supply by LDCs, but that subject is beyond the scope of AESC 2021.

Schedule MM-R1

In the AESC 2021 analysis, 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 they 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 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 $61 per kWh VoLL yields a total annual cost of the potentially load-related outages of about $17 million annually. Dividing by total distribution sales of about 19.8 TWh, this resulting per-MWh cost is $0.87 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.[404]

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.

[404] 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 2024, we evaluate avoided costs under two proposed sensitivities. These sensitivities include:

1. A natural gas price sensitivity with higher gas prices than were used in Counterfactual #1 ("High Gas Price Sensitivity")
2. A sensitivity which models a future with many DERs and increased levels of non-emitting electricity ("Increased Clean Electricity Sensitivity")

The selection and design of these sensitivities were identified through consensus discussion among members of the Study Group.

In the High Gas Price Sensitivity, energy prices are 21 percent higher than in Counterfactual #1. This is due to higher gas prices, which is the fuel that powers the marginal resource in most hours. Capacity prices are similar due to overall similarities in terms of peak demand requirements. RPS compliance costs are 3 to 10 percent lower (depending on the state), since renewables participating in the RPS policies are able to cover more of their costs through energy market revenues. As a result, they require less in the way of additional costs from the sale of RECs, which lowers the cost of RPS compliance.

In the Increased Clean Electricity Sensitivity, energy prices are 11 percent lower and capacity prices are 32 percent lower than in Counterfactual #5. The lower energy prices are due to the additional zero-marginal-cost renewable resources. The higher levels of exogenous renewable energy resources also drive down the capacity market prices by providing more exogenous firm capacity. Costs of REC compliance are similar between scenarios due to overall similarities in renewable builds in the near term, and market dynamics that prevent costs of RPS compliance from getting much higher than modeled in Counterfactual #5 in the longer term.

All of the summary costs described above are framed in terms of annual average costs (described on a 15-year levelized basis) for Massachusetts.

12.1. When and how to use these sensitivities

This section discusses caveats and considerations relating to the modeled sensitivities. In general, we perform sensitivity analysis to (a) explore the impact on results of choosing different input parameters, particularly when those input parameters are major drivers of the results and (b) explore the impact on results of hypothetical policies that could be enacted. In our sensitivity analysis, we perform the High Gas Price Sensitivity with the first reason in mind, while the Increased Clean Electricity Sensitivity relates to the second reason.

Schedule MM-R1

High Gas Price Sensitivity

The High Gas Price Sensitivity explores the impacts on avoided costs in a future where natural gas prices (as they are modeled in the electric sector) are higher. Synapse performs this sensitivity because natural gas prices are one of the inputs to which electric-sector modeling is most sensitive: all else being equal, modeled scenarios with higher natural gas prices will have higher energy prices, and lower capacity and REC prices (because more of these costs are paid for through the energy market). 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.

Increased Clean Electricity Sensitivity

The Increased Clean Electricity Sensitivity models a future with ambitious levels of energy efficiency, building electrification, and transportation electrification, as well as a policy which achieves 90 percent of electricity generation from sources other than fossil fuels in 2035 and all subsequent years. This sensitivity includes impacts from all DERs. It can be interpreted as a projection of expected energy prices, capacity prices, and other price series in a future with even more ambitious clean electricity policies than those posited in Counterfactual #5, or it could be interpreted as a projection of avoided costs for DERs beyond those modeled in this scenario.

This sensitivity is comparable to the "All-in Climate Policy Sensitivity" analyzed as part of AESC 2021.

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. Figure 59 illustrates the difference between the Henry Hub price we use in the main AESC 2024 counterfactuals and the gas price we use in this sensitivity (other series are shown for comparative purposes). Between 2026 and 2050, the high gas price is 65 percent higher than the main case, on average.

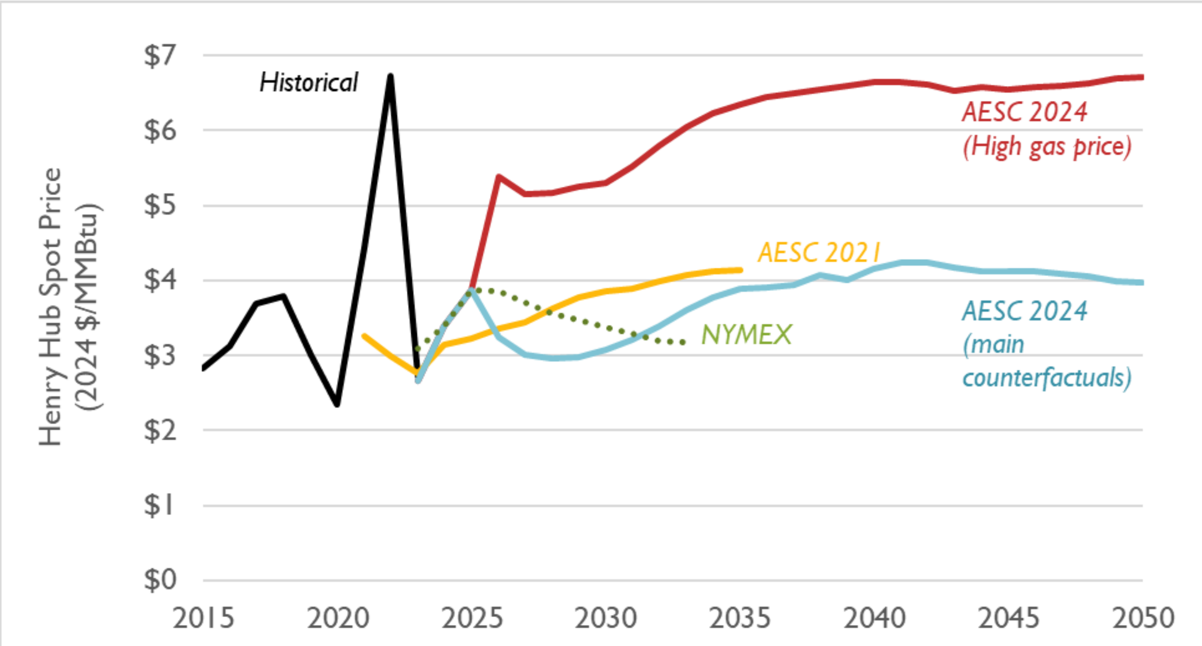
We create the high gas price trajectory depicted in Figure 59 by swapping out the AEO 2023 Reference case series used to create mid- and long-term Henry Hub gas prices in the main AESC counterfactuals for the AEO 2023 "Low oil and gas supply" case.[405] This series depicts a future with higher gas prices 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 2030 falls by 18 percent (relative to 2022 levels, and remains at that new level throughout the rest of

[405] For more information on these cases, see "Annual Energy Outlook 2023 Case Descriptions." U.S. Energy Information Administration. March 2023. Available at https://www.eia.gov/outlooks/aeo/assumptions/case_descriptions.php.

Schedule MM-R1

the study period). For comparison, the AEO 2023 Reference case we use as a data source for the gas price in the main AESC counterfactuals increases by 2 percent in 2030 and 15 percent in 2050, relative to 2020 levels).

Figure 59. Henry Hub price forecast in main AESC 2024 case and High Gas Price Sensitivity



We make 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 follows the methodology described for the main counterfactuals, as described above.

We note that this high gas price forecast is best used for examining likely avoided costs in a future where the long-term fundamentals behind natural gas prices are different than in the main counterfactuals, and where the grid is allowed to respond and build different resources accordingly. We can compare this high gas price sensitivities that test avoided costs under a gas price "shock" (i.e., a short-duration gas price), where the model is not allowed to change its build trajectory, or a change to near-term gas prices reflecting a sudden, unexpected change to the gas market (such as a pandemic or war) that is not necessarily linked to longer-term fundamentals.

Schedule MM-R1

Increased Clean Electricity Sensitivity

Generally speaking, this sensitivity envisions an alternate version of Counterfactual #5 where there are increased requirements to purchase non-emitting clean electricity in New England. [406] This sensitivity does not include any other modifications to inputs.[407] The policy that drives this incremental quantity of non-emitting electricity is called the Incremental Regional Clean Electricity Policy, or IRCEP.

Developing an Incremental Regional Clean Electricity Policy

The AESC 2024 Study Group identified percentage goals for clean electricity that would be useful for sensitivity testing. We use these percentage goals to estimate the quantity of incremental non-emitting supply modeled from 2024 through 2050.

Developing a clean electricity target

In AESC 2021, we relied on parameters from the "All Options" case in MA EEA's *Decarbonization Roadmap*.[408] 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. This trajectory began at 55 percent in 2020, reached 70 percent in 2025, 85 percent in 2030, and finally 90 percent in 2035.

Another key input was the trajectory being discussed nationally and in states around the country. For example, a goal of 100 percent non-emitting electricity by 2035 aligns with President Biden's goal of setting a path to net-zero emissions by 2035 and is similar to the 100 percent electricity requirement (by 2033) assumed for Rhode Island in all other counterfactuals.[409] Other states such as New York and Minnesota, have goals of 100 percent non-emitting electricity by 2040.[410] In New England, several states have renewable procurements that approach 80 or 90 percent electricity in the 2030 to 2040 time horizon (see Table 152).

[406] For the purposes of this sensitivity, resources that are defined as "emitting" include resources where electricity is generated from burning coal, natural gas, or oil. All other resources are non-emitting, and include wind, solar, hydro, nuclear, biomass, imports, municipal solid waste, and other miscellaneous resource types.

[407] During the course of sensitivity brainstorming, the AESC 2024 Study Group discussed other possible modifications to Counterfactual #5, including increasing levels of energy efficiency and/or electrification beyond those modeled in Counterfactual #5, or expanding this sensitivity to include new and different sources of electrification and DERs. These other modifications were ultimately not included in order to facilitate easier comparisons between this sensitivity and Counterfactual #5.

[408] Detailed annual and state-specific data was provided to Synapse Team by MA EEA via email in January through March 2021.

[409] See https://www.whitehouse.gov/briefing-room/statements-releases/2023/04/20/fact-sheet-president-biden-to-catalyze-global-climate-action-through-the-major-economies-forum-on-energy-and-climate/.

[410] See https://www.cesa.org/projects/100-clean-energy-collaborative/guide/table-of-100-clean-energy-states/.

Schedule MM-R1

Table 152. Renewable and clean energy procurement obligations modeled in Counterfactuals #1 through #6

	2024	2030	2035	2040	2045	2050
CT	32%	47%	66%	93%	93%	93%
ME	55%	80%	80%	80%	80%	80%
MA	62%	90%	91%	93%	96%	100%
NH	22%	23%	23%	23%	23%	23%
RI	28%	72%	100%	100%	100%	100%
VT	63%	71%	75%	75%	75%	75%

Note: Values in this table are derived from the analysis of renewable policies described in Chapter 7: Avoided Cost of Compliance with Renewable Portfolio Standards and Related Clean Energy Policies.

As a result of this review and Study Group discussion, the Study Group recommended a clean electricity target of 90 percent by 2035.

Implementation parameters for the Incremental Regional Clean Electricity Policy

To derive a quantity of incremental clean electricity required for the Incremental Regional Clean Electricity Policy (IRCEP), we first multiply the clean electricity goal (e.g., 90 percent regionwide by 2035) by the annual demand requirements for Counterfactual #5 to estimate how much total non-emitting supply needs to be provided each year. Second, we estimate the share of non-fossil generation already present in Counterfactual #5 and subtract this quantity from the shares calculated in the first step. Third, we multiply the resulting percentages by the annual load requirements (inclusive of both consumer electricity load and load requirements for storage) to determine TWh quantities of incremental clean electricity in each year. Finally, we perform series of steps to iterate on this TWh requirement:

- First, we model the policy as beginning in 2030. 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.[411] In this year, we set a starting goal of 80 percent clean electricity for 2030.
- 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 early 2030s. In this step, we interpolate between the starting goal (80 percent clean in 2030) and the final goal (90 percent clean in 2035), creating individual annual goals for each year in 2029 through 2034. The 90 percent goal is then maintained in all years from 2035 through 2050.

[411] This decision mirrors the assumption used in AESC 2021, which assumed the IRCEP would begin ramping up in 2025 (i.e., four years after the initial year of analysis).

Schedule MM-R1

- Third, we perform an interactive check to evaluate whether the clean electricity goals are achieved in modeling.[412]

As a result of these parameters, we develop a percentage trajectory described in Table 153, and a TWh trajectory described in Table 154.

Table 153. Clean electricity shares observed in Counterfactual #5 compared with clean electricity goals set for the Increased Clean Electricity Sensitivity

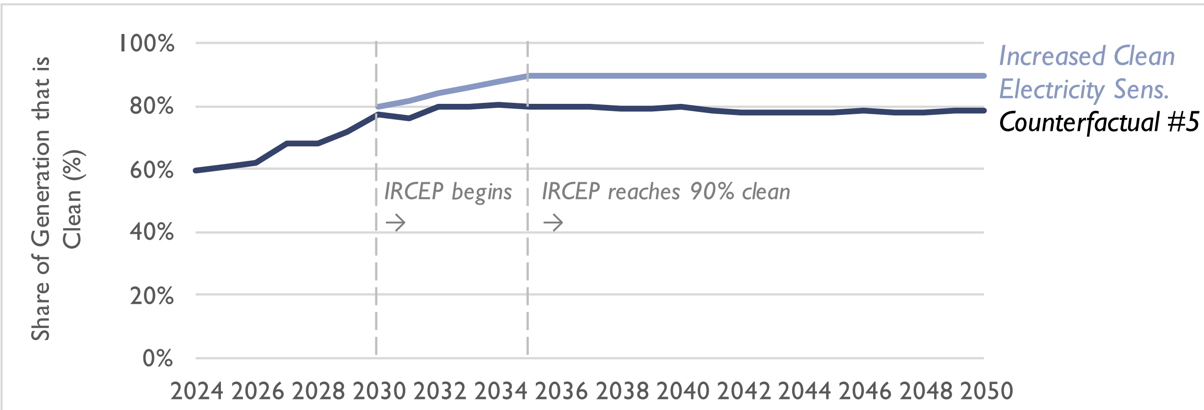
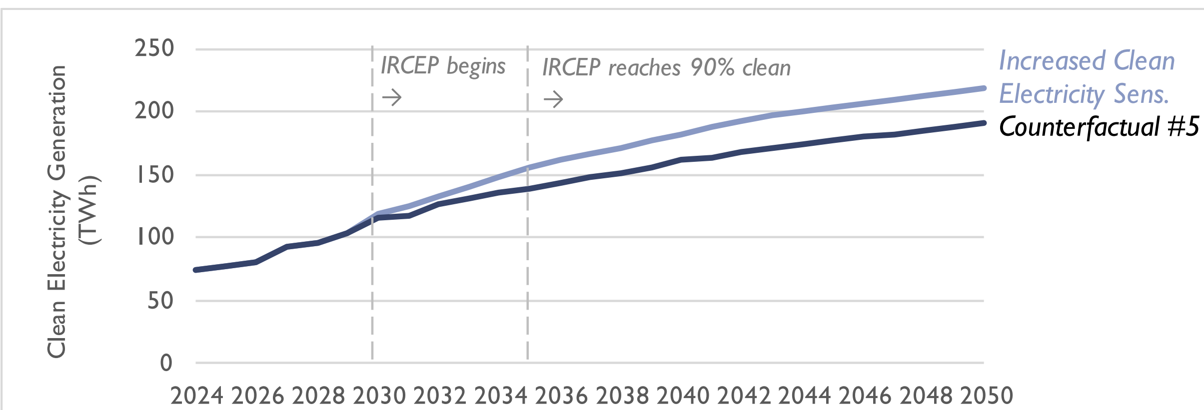


Table 154. Clean electricity generation observed in Counterfactual #5 compared with clean electricity generation goals set for the Increased Clean Electricity Sensitivity



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:

1. 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

[412] These goals may not necessarily be achieved in all modeled years as a result of curtailments and storage charging and dispatch.

Schedule MM-R1

cost-effective for each sensitivity. Depending on the year, resources added include onshore wind, utility-scale solar, and offshore wind.[413]

2. 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.

3. 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.

4. Ordinarily, an RPS policy identifies entities who must legally comply with the policy. For example, in practice, Massachusetts LSEs (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.

5. We do not model any additional renewable procurement policies beyond what is already modeled in the main AESC sensitivities.

Other resource builds

This sensitivity is allowed to build the same resources described in Section 4.5: *Anticipated non-renewable resource additions and retirements*. Reasons for economic builds of gas or battery storage resources 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).

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 tables in Section 7.1: *Assumptions and methodology* and Table 152 in

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[413] 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.

Schedule MM-R1

this section). In some states and years, this value is as low as 23 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 68 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 68 percent means that for every 1 MWh of energy efficiency installed, 0.68 MWh of IRCEP-derived clean energy would be avoided).
3. Third, we multiply the values calculated in Step 2 by each state's load.
4. Fourth, for each year, we divide the state-specific values calculated in Step 3 by the sum of all of the values in Step 3. This creates a set of weights.
5. Finally, we multiply the weights from Step 4 by the calculated cost of new entry for Class 1 renewables each year, for each state. This cost varies depending on which resources are marginal.

The resulting values are the cost of compliance under IRCEP for each state.[414]

Caveats to this sensitivity

The Increased Clean Electricity Sensitivity models 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. Accordingly, this sensitivity is 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 its own.

Importantly, because the IRCEP envisions a shift to 100 percent non-emitting electricity via an expansion of RPS-like programs, it implies that as time goes on, more of the avoided costs that are associated with non-embedded GHGs in Counterfactual #1 will be shifted towards the costs associated with the IRCEP and RPS programs. In other words, under this sensitivity, grid emissions will fall, leading to lower and lower avoided costs for non-embedded GHGs. Meanwhile, avoided costs for IRCEP and other RPS-like programs will rise, as these programs effectively become the mechanism for achieving GHG emission reductions. Under a 100-percent non-emitting future, there would be no avoidable GHG costs, but likely substantial IRCEP and REC costs.

[414] Note that this methodology differs slightly from the one used to allocate the IRCEP in AESC 2021. From a practical standpoint, for AESC 2024, this updated methodology does not produce markedly different results, and shifts the cost of compliance among some states by up to about +/- $0.50 per MWh.

Schedule MM-R1

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 155.

Schedule MM-R1

Table 155. Illustrative avoided costs for hypothetical energy efficiency measure installed in Massachusetts, Counterfactual #1 versus High Gas Price Sensitivity

		CF#1	High Gas Price	Differ-ence	% Differ-ence	Notes
Energy	*2024 $/MWh*	$50	$61	$10	20%	*4*
RPS compliance	*2024 $/MWh*	$23	$22	-$1	-5%	*4, 5*
Electric energy and cross-DRIPE	*2024 $/MWh*	$19	$21	$2	13%	*6*
GHG non-embedded	*2024 $/MWh*	$83-143	$83-143	$0	0%	*4,7,8*
Energy subtotal	***2024 $/MWh***	**$175-235**	**$187-246**	**$12**	**5-7%**	
Capacity	*2024 $/kW-year*	$53	$56	$3	6%	*9*
Capacity DRIPE	*2024 $/kW-year*	$24	$23	-$1	-5%	*9,10*
Regional T&D (PTF)	*2024 $/kW-year*	$69	$69	$0	0%	*11*
Value of reliability	*2024 $/kW-year*	<$1	<$1	$0	0%	*9*
Capacity subtotal	***2024 $/kW-year***	**$146**	**$149**	**$2**	**1%**	-
Capacity subtotal	***2024 $/MWh***	**$30**	**$30**	**$0**	**1%**	*12*
Total	***2024 $/MWh***	**$205-265**	**$217-277**	**$12**	**5-6%**	-

Notes:
[1] All costs are shown levelized over 15 years. All costs are shown for Massachusetts and are tabulated using the historical method in Massachusetts. Costs have not been adjusted for risk premiums or T&D loss factors.
[2] Results from CF#1 are reproduced from Table 3.
[3] AESC 2024 data is from the AESC 2024 User Interface. AESC 2024 values are levelized over 2024-2038, using a real discount rate of 1.74%.
[4] Energy, energy DRIPE, and GHG non-embedded costs are based on annual average numbers.
[5] Costs of RPS compliance are the sum of the per-MWh cost for all RPS programs active in this state.
[6] Electric energy and cross-DRIPE includes intrazonal energy DRIPE, E-G DRIPE, and E-G-E DRIPE. Interzonal effects are not included.
[7] For AESC 2024, GHG non-embedded costs for Connecticut, Maine, New Hampshire, and Rhode Island are based on a marginal abatement cost derived from the electric sector; GHG non-embedded costs for Massachusetts and Vermont are shown based on a range of a range of social cost of GHGs representing 1.5% and 2% discount rates. AESC 2024 social cost of GHG costs include impacts from CO2, CH4, and N2O pollution and exclude impacts from upstream emissions. The AESC 2024 report recommends the use of the EPA-derived SC-GHG, which includes costs for 1.5% and 2% discount rates.
[8] GHG non-embedded costs subtract embedded costs (RGGI, state-specific costs in Massachusetts) from the social cost of GHGs.
[9] Capacity, capacity DRIPE, and reliability values are shown for cleared values only. Uncleared values are not included.
[10] Capacity DRIPE values include intrazonal effects only. Interzonal effects are not included.
[11] "Regional Transmission (PTF)" values only include regional transmission costs. This cost does not include more localized transmission costs and does not include any distribution costs. These other avoided costs may be specifically calculated in each jurisdiction.
[12] Capacity values are converted to energy values using a load factor of 56%.

Energy prices

Table 156 compares the wholesale energy price results for this sensitivity with Counterfactual #1. These illustrative 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.[415] As in Counterfactual #1, natural gas generators are the marginal resource in most hours of this sensitivity and typically set the price.

Table 156. Comparison of energy prices for Massachusetts (2024 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Counterfactual 1	$50.36	$61.22	$57.34	$57.34	$33.55
High Gas Price Sensitivity	$60.58	$72.35	$65.80	$65.80	$43.61
% Change	20%	18%	15%	15%	30%

Notes: Levelization period is 2024–2038 and real discount rate is 1.74 percent.

Capacity prices

Compared to Counterfactual #1, the 15-year levelized capacity price in the High Gas Price Sensitivity are similar (see Table 157). Capacity prices are similar until the early 2030s, at which point this sensitivity features an increase in capacity prices. These higher capacity prices are then offset by lower capacity prices in the early and late 2040s. Overall, these cases feature similar capacity prices due to the fact that they use the same assumptions for peak demand; year-on-year differences, and even the 15- and 28-year average differences, are likely due to noise in the modeling results.

415 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 this sensitivity.

Table 157. Comparison of capacity prices in Rest-of-Pool (2024 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2024 Counterfactual #1	AESC 2024 High Gas Price Sensitivity
2024/2025	15	$2.66	$2.66
2025/2026	16	$2.53	$2.53
2026/2027	17	$2.48	$2.48
2027/2028	18	$2.48	$2.48
2028/2029	19	$2.57	$1.42
2029/2030	20	$2.83	$2.83
2030/2031	21	$4.25	$4.25
2031/2032	22	$4.25	$4.25
2032/2033	23	$5.66	$7.08
2033/2034	24	$5.66	$7.08
2034/2035	25	$7.08	$7.08
2035/2036	26	$5.66	$7.08
2036/2037	27	$4.25	$5.66
2037/2038	28	$7.08	$7.08
2038/2039	29	$7.08	$7.08
2039/2040	30	$5.66	$5.66
2040/2041	31	$10.53	$7.08
2041/2042	32	$7.08	$7.08
2042/2043	33	$5.66	$7.08
2043/2044	34	$7.08	$7.08
2044/2045	35	$7.08	$8.49
2045/2046	36	$9.51	$9.51
2046/2047	37	$9.51	$7.08
2047/2048	38	$11.94	$7.08
2048/2049	39	$8.49	$7.08
2049/2050	40	$8.49	$9.91
2050/2051	41	$7.08	$7.08
15-year levelized cost		**$4.73**	**$5.01**
Percent difference		**-**	**6%**

Notes: Levelization period is 2024/2025 to 2038/2039 and real discount rate is 1.74 percent. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2024 User Interface.

Cost of RPS compliance

Table 158 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 3 to 10 percent lower than those estimated for Counterfactual #1Generally, 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 158. Avoided cost of RPS compliance (2024 $ per MWh)

	CT	ME	MA	NH	RI	VT
Counterfactual #1	$17	$16	$25	$12	$23	$8
High Gas Price Sensitivity	$16	$15	$23	$12	$21	$8
Percent Change	-8%	-7%	-5%	-3%	-10%	-3%

Notes: Values are shown on a 15-year levelized basis, inclusive of energy losses.

Other avoided costs

Other avoided costs are unchanged or similar. Electricity DRIPE values are higher than in Counterfactual #1 because these values tend to follow energy prices (e.g., as energy prices increase so do energy DRIPE values). Capacity DRIPE values are lower due to minor differences in reserve margins in the mid-2030s, which have ripple effects in terms of what resources are online during this period, and which resources contribute to the supply curve.

Increased Clean Electricity Sensitivity

This sensitivity is a modification of Counterfactual #5 with additional clean electricity resources. As a result, all comparisons examined in this section compare this sensitivity with Counterfactual #5. A summary of the changes in avoided costs is shown in Table 159. 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.

Schedule MM-R1

Table 159. Illustrative avoided costs for hypothetical energy efficiency measure installed in Massachusetts, Counterfactual #5 versus Increased Clean Electricity Sensitivity

		CF#5	Incr. Clean Elec.	Differ-ence	% Differ-ence	Notes
Energy	*2024 $/MWh*	$50	$45	-$5	-11%	*4*
RPS compliance	*2024 $/MWh*	$23	$23	$0	0%	*4, 5*
IRCEP compliance	*2024 $/MWh*	$0	$0	$0	0%	*13*
Electric energy and cross-DRIPE	*2024 $/MWh*	$19	$18	$0	-2%	*6*
GHG non-embedded	*2024 $/MWh*	$83-143	$83-143	$0	0%	*4,7,8*
Energy subtotal	*2024 $/MWh*	**$175-235**	**$169-229**	**-$6**	**-2- -3%**	
Capacity	*2024 $/kW-year*	$49	$34	-$16	-32%	*9*
Capacity DRIPE	*2024 $/kW-year*	$31	$31	$0	-1%	*9,10*
Regional Transmission (PTF)	*2024 $/kW-year*	$69	$69	$0	0%	*11*
Value of reliability	*2024 $/kW-year*	<$1	<$1	<$0	-2%	*9*
Capacity subtotal	***2024 $/kW-year***	**$149**	**$133**	**-$16**	**-11%**	*-*
Capacity subtotal	***2024 $/MWh***	**$30**	**$27**	**-$3**	**-11%**	*12*
Total	***2024 $/MWh***	**$205-265**	**$196-256**	**-$9**	**-3- -4%**	**-**

Notes:
[1] All costs are shown levelized over 15 years. All costs are shown for Massachusetts and are tabulated using the historical method in Massachusetts. Costs have not been adjusted for risk premiums or T&D loss factors.
[2] Results from CF#5 are reproduced from Table 3.
[3] AESC 2024 data is from the AESC 2024 User Interface. AESC 2024 values are levelized over 2024–2038, using a real discount rate of 1.74%.
[4] Energy, energy DRIPE, and GHG non-embedded costs are based on annual average numbers.
[5] Costs of RPS compliance are the sum of the per-MWh cost for all RPS programs active in this state.
[6] Electric energy and cross-DRIPE includes intrazonal energy DRIPE, E-G DRIPE, and E-G-E DRIPE. Interzonal effects are not included.
[7] For AESC 2024, GHG non-embedded costs for Connecticut, Maine, New Hampshire, and Rhode Island are based on a marginal abatement cost derived from the electric sector; GHG non-embedded costs for Massachusetts and Vermont are shown based on a range of a range of social cost of GHGs representing 1.5% and 2% discount rates. AESC 2024 social cost of GHG costs include impacts from CO2, CH4, and N2O pollution and exclude impacts from upstream emissions. The AESC 2024 report recommends the use of the EPA-derived SC-GHG, which includes costs for 1.5% and 2% discount rates.
[8] GHG non-embedded costs subtract embedded costs (RGGI, state-specific costs in Massachusetts) from the social cost of GHGs.
[9] Capacity, capacity DRIPE, and reliability values are shown for cleared values only. Uncleared values are not included.
[10] Capacity DRIPE values include intrazonal effects only. Interzonal effects are not included.
[11] "Regional Transmission (PTF)" values only include regional transmission costs. This cost does not include more localized transmission costs and does not include any distribution costs. These other avoided costs may be specifically calculated in each jurisdiction.
[12] Capacity values are converted to energy values using a load factor of 56%.
[13] In this illustrative example, the IRCEP value is shown for Massachusetts. Depending on the state and year, the IRCEP value varies from $0 per MWh to $4 per MWh.

Schedule MM-R1

Energy prices

Table 160 compares the wholesale energy price results for this sensitivity with Counterfactual #5. These illustrative comparisons use 15-year levelized costs for the Massachusetts reporting region. We find that in the near-term, prices are similar. The Increased Clean Electricity Sensitivity energy prices diverge from those in Counterfactual #5 in the early 2030s when additional renewable resources come online, producing lower energy costs. The increase in renewable resources reduces energy prices because they have zero-marginal operating costs. After the near-term 15-year levelization period, as electricity demand increases, energy prices in the Increase Clean Electricity Sensitivity increase. In general, this causes this scenario to have energy prices in the 2040s that approach those modeled in Counterfactual #5.

Table 160. Comparison of energy prices for Massachusetts (2024 $ per MWh, 15-year levelized)

	Annual All hours	Winter Peak	Winter Off-Peak	Summer Peak	Summer Off-Peak
Counterfactual 5	$50.38	$61.64	$58.06	$58.06	$31.12
Inc. Clean Elec. Sensitivity	$45.06	$55.53	$51.66	$51.66	$27.36
% Change	-11%	-10%	-11%	-11%	-12%

Notes: Levelization period is 2024–2038 and real discount rate is 1.74 percent.

Capacity prices

Compared to Counterfactual #5, the 15-year levelized capacity price in the Increased Clean Electricity Sensitivity is lower (see Table 161). Capacity prices in the Clean Electricity Sensitivity are identical or similar to prices in Counterfactual #5 from FCA 15 through FCA 22. Beginning in FCA 23, the Increased Clean Electricity Sensitivity features a decrease in capacity prices due to higher levels of renewable energy being deployed by the IRCEP program. The additional renewable energy provides extra firm capacity (relative to Counterfactual #5), which leads to larger reserve margins and shifts in the capacity market supply curve to the right. As a result, the capacity market clears at a lower price. These trends persist throughout the study period as new MW of clean energy is continually added to satisfy the additional IRCEP requirements, keeping reserve margins high and capacity prices low.

Schedule MM-R1

Table 161. Comparison of capacity prices in Rest-of-Pool (2024 $ per kW-month)

Commitment Period (June to May)	FCA	AESC 2024 Counterfactual #5	AESC 2024 Increased Clean Electricity Sensitivity
2024/2025	15	$2.61	$2.61
2025/2026	16	$2.53	$2.53
2026/2027	17	$2.48	$2.48
2027/2028	18	$2.48	$2.48
2028/2029	19	$1.42	$1.42
2029/2030	20	$2.83	$2.83
2030/2031	21	$2.83	$2.83
2031/2032	22	$1.42	$1.42
2032/2033	23	$4.25	$2.83
2033/2034	24	$2.83	$1.42
2034/2035	25	$7.08	$4.25
2035/2036	26	$8.49	$5.66
2036/2037	27	$7.08	$1.42
2037/2038	28	$7.08	$4.25
2038/2039	29	$7.08	$2.83
2039/2040	30	$7.08	$2.83
2040/2041	31	$9.51	$1.42
2041/2042	32	$8.49	$2.83
2042/2043	33	$9.51	$2.83
2043/2044	34	$9.51	$2.83
2044/2045	35	$9.51	$1.42
2045/2046	36	$8.49	$2.83
2046/2047	37	$7.08	$2.83
2047/2048	38	$5.66	$1.42
2048/2049	39	$7.08	$2.83
2049/2050	40	$9.51	$2.83
2050/2051	41	$7.08	$1.42
15-year levelized cost		**$4.51**	**$2.93**
Percent difference			**-35%**

Notes: Levelization period is 2024/2025 to 2038/2039 and real discount rate is 1.74 percent. Data on clearing prices for other counterfactuals and regions can be found in the AESC 2024 User Interface.

Cost of RPS compliance

Table 162 shows how the cost of RPS compliance changes in the Increased Clean Electricity Sensitivity, relative to Counterfactual #5. Across all the states, we observe minimal changes in the cost of RPS compliance, on the order of less than 1 percent. This result could be viewed as counter-intuitive—after all, Increased Clean Electricity Sensitivity features greater demand for renewables, which (all else being equal) ought to drive an increase in RECs and RPS compliance costs.

However, the IRCEP policy does not begin until 2030. Starting in that year, it causes small, incremental renewable builds (relative to Counterfactual #5) as the overall share of non-emitting generation increases from about 80 percent in Counterfactual #5 to about 90 percent in the Increased Clean Electricity Sensitivity. In other words, these two scenarios feature identical renewable builds for the first six years, and then similar renewable builds for the remaining nine years of the 15-year levelization. In addition, at the start of the IRCEP period, the regional pool is still experiencing an excess of RECs which were banked in the late 2020s as a result of renewable procurements exceeding RPS demand. This further depresses RPS prices. Finally, several states experience situations in the mid- to late-2030s

Schedule MM-R1

where the Alternative Compliance Payment level is reached, which places an upward ceiling on REC price and the possibilities for increases in the RPS compliance cost. In general, in most states, these trends persist throughout the study period, causing little differences between RPS compliance costs in the Increased Clean Electricity Sensitivity and Counterfactual #5.

Table 162. Avoided cost of RPS compliance (2024 $ per MWh)

	CT	ME	MA	NH	RI	VT
Counterfactual #5	$17	$16	$25	$12	$23	$8
Inc. Clean Electricity Sensitivity	$17	$16	$25	$12	$23	$8
Percent Change	<1%	<1%	<1%	<1%	<1%	<1%

Notes: Values are shown on a 15-year levelized basis, inclusive of energy losses. Does not include IRCEP costs of compliance.

Other avoided costs

We note that the IRCEP value shown in Table 159 for Massachusetts is $0 per MWh. This is because Massachusetts' other assumed RPS programs currently exceed the non-emitting generation requirements of the IRCEP. Other states with similarly ambitious clean energy requirements (such as Rhode Island, Maine, or Vermont) also see very low or zero IRCEP compliance costs. Meanwhile, other states where the assumed non-IRCEP clean energy requirements are lower than 80-90 percent see higher compliance costs as these states shoulder a greater share of the IRCEP program.

Values in other avoided cost categories are similar or unchanged, as a result of the overall similarity between the Increased Clean Electricity Sensitivity and Counterfactual #5 in the near- and mid-term.

Other considerations

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.

Schedule MM-R1

APPENDIX A: USAGE INSTRUCTIONS

This appendix describes how AESC 2024 users can extrapolate values post-2050, 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-2050

For AESC 2024, the Synapse Team recommends using the same extrapolation approached used in AESC 2021. In developing our recommendation, the Synapse Team notes the following:

- The Study Group expressed a desire for a single extrapolation methodology for use across all avoided cost categories for ease of use.
- The Study Group expressed a desire for an extrapolation technique to be both (a) based on data from years close to the extrapolation period and (b) 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.

Specifically, the Synapse Team recommends an approach that estimates a compound annual growth rate (CAGR) of the linearly regressed trend of the last six years of each avoided cost series. Figure 60 displays an illustrative version of this approach; a CAGR is estimated over the red series. This regression step is effectively a smoothing step, as it reduces the impact from individual "noisy" datapoints.[416]

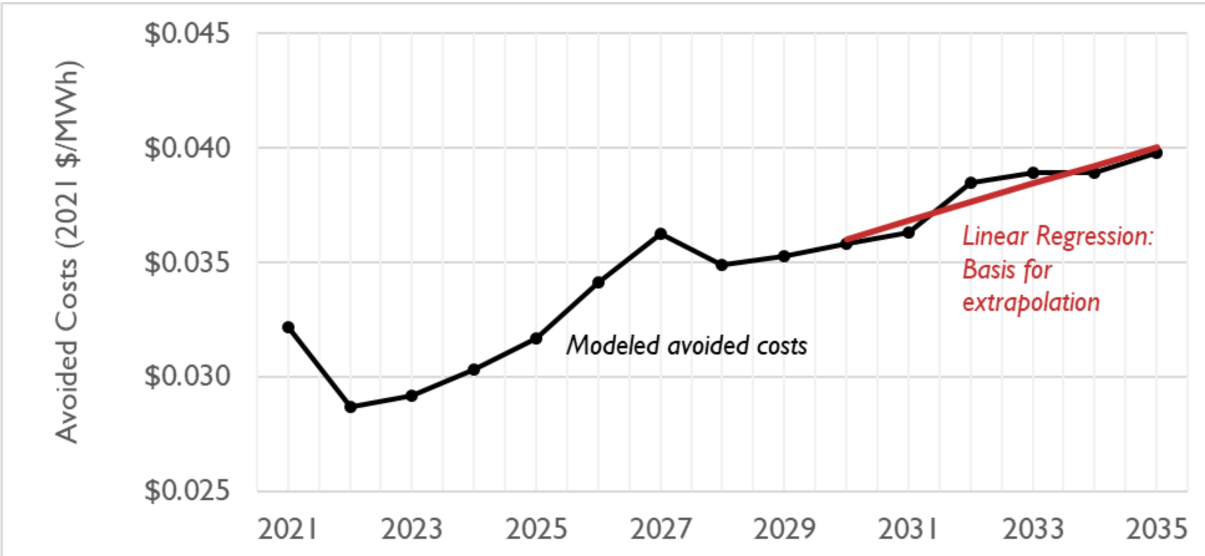
Note that through the use of the *AESC 2021 User Interface* and other appendices, readers of AESC 2024 can calculate their own extrapolated values if their policy context requires some alternate methodology

[416] There are three exceptions to this recommendation. First, we estimate capacity price shifts in 2051–2068 (used to calculate capacity DRIPE benefits in these years) by examining the median price shift from 2028 through 2050. 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). We chose this period because it is the period modeled under the future seasonal capacity market. The second exception is for reserve margins, which use a median of the 2028–2050 for the 2051–2068 time period for the same reasons as price shifts. The third 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 2068.

Schedule MM-R1

to the one recommended above. See Appendix A of AESC 2021 for more discussion on previous extrapolation techniques used in AESC studies.[417]

Figure 60. Example of linear regression over a short period



Note: Reproduced from Figure 61 in AESC 2021.

Levelization calculations

The AESC Study generally presents levelized costs throughout on a 15-year basis, although the study's appendices also provide levelized costs over two other periods. The three levelization periods are as follows:

- 10-year: 2024 to 2033
- 15-year: 2024 to 2038
- 30-year: 2024 to 2053

All levelized costs are calculated in AESC using a real discount rate of 1.74 percent.

To calculate levelized costs beyond the three periods documented above, readers of AESC will require (a) a real discount rate (1.74 percent or otherwise specified), (b) the number of years and timeframe over which costs are to be levelized (e.g., 10 years—2024 through 2033 inclusive), and (c) the specific

[417] Synapse Energy Economics. *Avoided Energy Supply Components in New England: 2021 Report (AESC 2021)*. May 15, 2021. Available at https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.

avoided cost values for the relevant reporting region. Equation 12 describes the formula used to estimate a levelized cost within Excel.

Equation 12. Excel formula used for calculating levelized costs

$$Levelized\ cost = -PMT(DiscountRate, NumberOfYears, NPV(DiscountRate, StreamOfCostsWithinPeriod))$$

Converting constant 2024 dollars to nominal dollars

Unless specifically noted, this report presents all dollar values in 2024 constant dollars. To convert constant 2024 dollars into nominal (current) dollars, apply the formula described in Equation 13. Inflator and deflator conversion factors for AESC 2024 are presented in *Appendix E: Common Financial Parameters*.

Equation 13. Nominal-constant dollar conversion

$$Nominal\ Value = \frac{Constant\ Value\ (in\ 2024\ \$)}{Annual\ Conversion\ Factor\ to\ 2024\ \$}$$

Comparisons to previous AESC studies

A reader of the AESC 2024 Study may prepare comparisons of the AESC 2024 Study's 15-year levelized avoided costs with the 2021 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 2024 and AESC 2021 (for the relevant reporting region and costing period)
- Convert the AESC 2021 values from 2021 dollars to 2024 dollars
- Calculate the 15-year levelized cost in 2024 dollars using the AESC 202 real discount rate (1.74 percent)

Schedule MM-R1

APPENDIX B: DETAILED ELECTRIC OUTPUTS

AESC 2024 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 2024 User Interface* (see *Appendix F: User Interface* for more information).

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. Energy DRIPE for intrastate and rest-of-pool for 2024 installations
5. Electric Cross-DRIPE
6. Avoided unit cost of electric capacity by demand reduction bidding strategy
7. Capacity DRIPE for intrastate and rest-of-pool for 2024 installations
8. Avoided reliability costs
9. 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).

There are two important considerations to applying Appendix B in state benefit-cost (BC) models.

- First, some of the values in the $-per-kWh categories, such as energy DRIPE, change depending on the measure vintage selected in the *AESC 2024 User Interface*.
- Second, some of the values in the $-per-kW categories, such as uncleared capacity DRIPE, change depending on both the measure vintage and the measure lifetime selected in the *AESC 2024 User Interface*. The entire set of avoided costs shown for all measure lives is contained in the “Appendix J” tabs in the *AESC 2024 User Interface*.

To address this first consideration, users should modify the measure vintage to reflect each of the years being analyzed in their benefit-cost analyses (e.g., 2025, 2026, and 2027), and generate a separate Appendix B for each vintage. This will produce separate, more specific series of avoided costs for all $-

Schedule MM-R1

per-kWh values and for the avoided cost of pooled transmission facilities (PTF) (note that not all of these values will vary by vintage, but generating separate Appendix B tables for each vintage will make it easier to implement these tables in most states' BC models. In addition, users should also generate a separate set of Appendix J tables for each measure vintage. These tables should be used to inform avoided costs related to cleared and uncleared capacity, capacity DRIPE, and value of reliability. In other words, users should not simply use the columns for capacity, capacity DRIPE, and value of reliability as they are shown in Appendix B, as these show avoided costs for only the measure life selection specified on the "UserInterface" page.

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. For the weather year 2002 used in AESC 2024, these costing periods are defined as follows:[418]

- 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 (1,344 Hours, 15.3 percent of 8,760)[419]
- 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 (1,582 Hours, 18.1 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 (2,736 Hours, 31.2 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 (3,096 Hours, 35.3 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 14).

Equation 14. Calculation of annual avoided electricity cost

$$\begin{aligned}
&Annual\ avoided\ electricity\ cost \\
&\qquad = (15.3\% \times Summer\ OnPeak) + (18.1\% \times Summer\ OffPeak) \\
&\qquad + (31.2\% \times Winter\ OnPeak) + (35.4\% \times Winter\ OffPeak)
\end{aligned}$$

The specific wholesale avoided energy costs included in Appendix B are explained below.

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[418] ISO New England. Last accessed September 25, 2023. "Glossary and Acronyms." *Iso-ne.com.* Available at https://www.iso-ne.com/participate/support/glossary-acronyms/.

[419] ISO New England holidays are New Year's Day, Memorial Day, July 4th, Labor Day, Thanksgiving Day, and Christmas.

- *Wholesale avoided costs of electricity energy*. Annual wholesale electric energy prices are outputted from the EnCompass simulation runs.[420]

- *Wholesale REC costs to load*. Annual avoided REC costs are specific to each state.

- *Wholesale non-embedded GHG costs.* Annual estimates of non-embedded CO_2 values are provided for each of the four energy costing periods.

- *Wholesale energy DRIPE*. Separate projections are provided for wholesale intrastate and rest-of-pool energy DRIPE.[421] 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. All of these values except the Avoided cost for PTF should be referenced on the "Appendix J" tabs in the *AESC 2024 User Interface*. These values ,as they are shown on the Appendix B tab, show only the avoided costs for a single selected measure lifetime.

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.

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 under the current market, 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 five years after the current year.

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[420] 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 and energy components*.

[421] DRIPE vintage years are available for 2024 through 2028 within the *AESC 2024 User Interface*.

Schedule MM-R1

Wholesale capacity DRIPE projections are provided for intrastate and Rest-of-Pool energy DRIPE for installation year 2024. Users should apply capacity DRIPE values in accordance with relevant state regulations governing treatment of capacity DRIPE.

Wholesale reliability projections are provided for installation year 2024. Both cleared and uncleared values are provided.

Three separate sets of values are provided for capacity, capacity DRIPE, and reliability for each of the three capacity costing frameworks: the current capacity market, which extends through 2027, the future summer capacity costing period, which applies to measures with summer peaking values that provide savings in 2028 and later years, and the future winter capacity costing period, which applies to measures with winter peaking values that provide savings in 2028 and later years. Future summer and winter values are provided only in situations where we have modeled a clearing price (or need for seasonal capacity) in those years.

Finally, in the *AESC 2024 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 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. This percentage, as it appears in the *AESC 2024 User Interface,* is not intended to be a primary input for producing usable avoided costs. Instead, its purpose is to provide demonstrative values within the "Appendix J" tabs of the *AESC 2024 User Interface.* Users should plan to develop their own values for x and apply these in their BC models.

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 2024 User Interface* 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 15.

Equation 15. Converting from wholesale to retail avoided costs

$$Avoided\ retail\ cost = (avoided\ wholesale\ cost) \times (1 + losses) \times (1 + wholesale\ risk\ premium)$$

Schedule MM-R1

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. We note that Study Group members in Vermont utilize values of 4 percent for summer months and 0 percent for winter months; the *AESC 2024 User Interface* allows users to enter a separate wholesale risk premium value for each season, or set these values to be the same.[422]

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.[423] Short-term procurements (for six months or a

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[422] In general, these seasonal wholesale risk premium values are applied to the relevant season. For example, the summer wholesale risk premium is applied to summer on-peak energy values, while the winter wholesale risk premium is applied to winter on-peak energy values. There are two exceptions to this. First, the two seasonal wholesale risk premium values are averaged and applied to cross-DRIPE values, since these avoided costs represent avoided costs that span the entire year. Second, summer wholesale risk premium values are applied to capacity market values that get a wholesale risk premium (e.g., uncleared capacity, uncleared capacity DRIPE, and uncleared reliability) for the near-term years when the current capacity market structure applies. In future years, where we model a season capacity market, each season receives the associated seasonal wholesale risk premium value.

[423] Note that these bids are confidential and cannot be made public.

Schedule MM-R1

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.[424]

AESC 2024 applies the same wholesale risk premium to avoided wholesale energy prices and to avoided wholesale capacity prices.[425]

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 2024 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.

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.[426]

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.

[424] 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.

[425] 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.

[426] The forecast of capacity costs from the FCM do not reflect these losses; therefore, forecasted capacity costs should be adjusted to account for them.

Schedule MM-R1

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 163 displays the recommended loss factors, along with the average factors from which they are derived. We note that previous editions of AESC (such as AESC 2018) have typically recommended a loss factor of 8 percent be applied to all avoided cost categories.[427] However, this loss factor is average (rather than marginal) and focused on-peak hours (rather than all hours). As a result, AESC 2024 utilizes the same loss factors as AESC 2021. See Section 4.3 *New England system demand and energy components* for more discussion on deriving marginal loss factors.

Table 163. Loss factors recommended for use in AESC 2024

	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 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.

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.[428] On average, system PTF losses between 2010 and 2020 are 1.6 percent. This is the same number described in AESC 2021 and AESC 2018.

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427 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.

428 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.

Schedule MM-R1

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, AESC 2024 re-uses the same approach for average losses used in 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 164 summarizes which retail factors are applied when converting wholesale avoided cost to retail avoided costs. Losses apply to all avoided costs.[429] 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.

Table 164. 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	✓	

[429] 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.

Schedule MM-R1

Guide to applying the avoided costs

AESC 2024 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 shown in the "Appendix B" tab of the *AESC 2024 User Interface* are calculated using the following default values:

1. Wholesale risk premium: 8 percent
2. Losses: 9 percent for dollar-per-kWh values and 16 percent for dollar-per-kW values[430]
3. Real discount rate: 0.81 percent

[430] Each program administrator should obtain or calculate the losses applicable to its specific system as described in Chapter 10 on avoided T&D costs.

Schedule MM-R1

Appendix C: Detailed Natural Gas Outputs

The following appendix provides descriptions of the avoided natural gas costs in the AESC Study by year and by end use. It also includes descriptions of natural gas supply DRIPE and natural gas cross-DRIPE values by year, and by end use. All values are provided in the standalone Excel workbook titled "Appendix C."

Avoided natural gas costs by end use

The Excel workbook titled "Appendix C" includes forecasts of avoided natural gas costs by year and end use for three New England sub-regions: southern New England or SNE (Connecticut, Rhode Island, Massachusetts), northern New England or NNE (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). Program administrators must determine if their LDC has avoidable LDC margins and should pick the appropriate value stream accordingly. The relevant tabs for this topic include the following:

- No-Margin-SNE: Avoided gas costs for SNE without a retail margin
- Some-Margin-SNE: Avoided gas costs for SNE with a retail margin
- No-Margin-NNE: Avoided gas costs for NNE without a retail margin
- Some-Margin-NNE: Avoided gas costs for NNE with a retail margin
- No-Margin-VT: Avoided gas costs for VT without a retail margin

The tables show avoided costs for the following end uses: Residential non-heating, water heating, heating, and all; C&I 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.

Avoided natural gas costs by costing period

The Excel workbook titled "Appendix C" also includes avoided natural gas costs for each of the six costing periods, as well as the design day (with and without retail margins). The values for each costing

Schedule MM-R1

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 these tables. These are found on the tabs titled "Avoided-Gas-Costs-SNE" (for avoided costs by costing period for Southern New England) and "Avoided-Gas-Costs-NNE" (for avoided costs by costing period for Northern New England).

The values in these tables can be used to calculate the avoided natural gas costs for programs that reduce gas use during specific periods during the year. For example, the Baseload avoided cost would be applied to a reduction in gas use (in MMBtu) that is spread equally over all days of the year. The Highest 10 Days avoided cost would be applied to a reduction in gas use that occurs only during the 10 days of highest gas use. The Winter values would be used to calculate the avoided natural gas costs for a program that reduces gas use over the November through March winter season (i.e., more than 90 days, and up to 151 days each year).

Note that because the load shape for residential non-heating is 100 percent baseload, the avoided costs for Residential Non-heating in these tables will match the Baseload values shown in the avoided costs by end-use tables.

Natural gas supply and cross-fuel DRIPE

The standalone Excel workbook titled "Appendix C" includes 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. These are found in the tabs titled in the format "DRIPE_CT," where each state has its own tab for natural gas supply and cross-fuel DRIPE. The standalone "Appendix C" workbook only includes results for Counterfactual #1; results for other counterfactuals can be found in each of the accompanying AESC 2024 User Interface Excel workbooks on the tab titled "Appendix C".[431]

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 165.[432] An analogous set of values are shown for zone-on-Rest-of-Pool DRIPE in Columns 11 through 18.

[431] We observe that in practice, these values tend to not differ substantially across counterfactuals.

[432] 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.)

Schedule MM-R1

Table 165. 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%	40%
Residential	Hot water	27%	
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.

"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.

Schedule MM-R1

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 levelization periods used elsewhere in AESC: 10 years, 15 years, and 30 years. Note that these costs and emission values are assumed to be the same for all states and reporting regions in New England.

The Excel workbook titled "Appendix D" includes a tab titled "AvoidedPetCosts," which lists 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).

Four tabs are also included for DRIPE, for four different specific petroleum products. These tabs modify the values shown in Table 126 by multiplying those by the adjustment factors in Table 127. DRIPE values are provided for home heating oil (DFO), residual fuel oil (RFO), motor gasoline, and diesel used for motor vehicle purposes (DFO_MV).

All values are provided in the standalone Excel workbook titled "Appendix D."

Schedule MM-R1

APPENDIX E: COMMON FINANCIAL PARAMETERS

This chapter presents values for converting nominal dollars to constant 2024 dollars (2024 $) as well as a real discount rate for calculating illustrative levelized avoided costs. These values are used throughout the AESC 2024 Study, including in calculations that convert constant to nominal dollars and in levelization calculations. Note also that the *AESC 2024 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, this is higher than used in the previous study but similar to that used in prior years. Those values are below:

- The value for converting between future nominal dollars and constant 2024 $ is a long-term inflation rate of 2.25 percent (higher than the 2.0 percent used in the past).
- The real discount rate is 1.74 percent (versus 0.81 percent in AESC 2021, but similar to that used in prior studies).

Conversion of nominal dollars to constant 2024 dollars

Unless otherwise stated, all dollar values in AESC 2024 are in 2024 dollars. Therefore, a set of inflators is needed to convert prior year nominal dollars into 2024 dollars, and a set of deflators to convert future year nominal dollars into 2024 dollars. Those values are presented in Table 166. The future deflators are calculated by using the T-Bill rates for inflation-adjusted bonds. This is a change from the past when we have used other inflation sources such as the Congressional Budget Office (CBO). The new method is fully consistent with the data and methodology used to calculate the nominal deflator. The historical inflators are calculated from GDP chain-type price index published by the U.S. Federal Reserve.[433] The inflation rate during 2023 has been higher than typical in the range of 3.2 percent.[434] However, expectations are that this will decline in the future. For future inflation we have used the differential between the nominal and the real T-Bill rates. That 30-year inflation rate is calculated to be 2.25 percent. This is also consistent with using the Federal Reserve for the historical price index. As a result, we recommend an inflation rate of 3.2 percent for 2023 and 2.25 percent for the future.

Table 166. GDP price index and inflation rate

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2024 $
2000	78.02		1.720
2001	79.81	2.30%	1.681
2002	81.01	1.50%	1.657

[433] U.S. Federal Reserve Bank of St, Louis, Gross Domestic Product Chain-type Price Index. Accessed August 8, 2023.

[434] Economic projections of the Federal Reserve Board members, June 2023, median PCE inflation for 2023. Accessed August 8, 2023.

Schedule MM-R1

Year	GDP Chain-Type Price Index	Annual Inflation	Conversion from nominal $ to 2024 $
2003	82.64	2.00%	1.624
2004	84.84	2.67%	1.582
2005	87.49	3.12%	1.534
2006	90.21	3.11%	1.488
2007	92.65	2.71%	1.448
2008	94.40	1.88%	1.422
2009	95.02	0.66%	1.412
2010	96.16	1.21%	1.396
2011	98.16	2.07%	1.367
2012	100.00	1.88%	1.342
2013	101.77	1.77%	1.319
2014	103.66	1.86%	1.295
2015	104.66	0.96%	1.282
2016	105.70	1.00%	1.270
2017	107.74	1.93%	1.246
2018	110.34	2.41%	1.216
2019	112.30	1.78%	1.195
2020	113.81	1.35%	1.179
2021	118.92	4.49%	1.128
2022	127.23	6.98%	1.055
2023	131.30	3.20%	1.022
2024	134.25	2.25%	1.000
2025	137.28	2.25%	0.978
2026	140.37	2.25%	0.956
2027	143.53	2.25%	0.935
2028	146.76	2.25%	0.915
2029	150.07	2.25%	0.895
2030	153.45	2.25%	0.875
2031	156.90	2.25%	0.856
2032	160.44	2.25%	0.837
2033	164.05	2.25%	0.818
2034	167.74	2.25%	0.800
2035	171.52	2.25%	0.783
2036	175.38	2.25%	0.765
2037	179.33	2.25%	0.749
2038	183.37	2.25%	0.732
2039	187.50	2.25%	0.716
2040	191.72	2.25%	0.700
2041	196.04	2.25%	0.685
2042	200.46	2.25%	0.670
2043	204.97	2.25%	0.655
2044	209.59	2.25%	0.641
2045	214.31	2.25%	0.626
2046	219.13	2.25%	0.613
2047	224.07	2.25%	0.599
2048	229.12	2.25%	0.586
2049	234.28	2.25%	0.573
2050	239.55	2.25%	0.560

Schedule MM-R1

For the future years in our analysis, we use a long-term inflation rate of 2.25 percent based on 30-year T-Bills. This is higher than the 2 percent rate used previously. The 2.25 percent inflation rate is also consistent with the 20-year annual average inflation rate from 2003 to 2022 of 2.26 percent, derived from the GDP chain-type price index. We also examined projections of long-term inflation made by the CBO in January 2023. The CBO GDP price index was 2.5 percent for 2024, 2.1 percent for 2025 and 2.0 percent for future years.[435] Note also that the annual inflation rates used in the 2023 AEO vary between 2.1 and 2.2 percent.[436]

Real discount rate and inflation rate

The real discount rate is based on the rate for the inflation-adjusted 30-year T-Bills for the same period as used for the nominal rate. For this report the real discount rate is 1.74 percent, compared to the nominal rate of 4.03 percent.

These two values together determine an inflation rate. To determine the inflation rate we use the formula in Equation 16. This is a change from the previous methodology where the inflation rate was used to determine the real discount rate.

Equation 16. Calculating the inflation rate

$$Inflation\ rate = \frac{1 + nominal\ discount\ rate}{1 + real\ discount\ rate} - 1$$

For the nominal discount rate, past AESC studies have generally used 30-year long-term Treasury bills. AESC 2024 makes the same assumption. Rates on Treasury bills have declined considerably in 2021 and 2022 but have been fairly stable in 2023 although increasing in recent months. The rates for 30-year T-bills have ranged from 3.54 to 4.32 percent in 2023 (see Figure 61).

Since AESC 2024 requires a long-term value, we use the average of the 30-year T-Bill rates for the most recent 30 days for the nominal discount rate of 4.03 percent.[437] This is slightly higher the 3.37 percent used In AESC 2018, and less than the 4.36 percent rate used in AESC 2015. This results in a nominal discount rate of 4.03 percent. The resultant future nominal price indices are shown in shown in Table 167.

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[435] CBO, The Budget and Economic Outlook: Fiscal Years 2023 to 2033, Table 2-1, page 35, January 2023.

[436] U.S. EIA. "Annual Energy Outlook 2023." *Eia.gov.* Available at https://www.eia.gov/outlooks/aeo/tables_ref.php.

[437] U.S. Department of the Treasury, Daily Treasury Par Yield Curve Rates. https://home.treasury.gov/resource-center/data-chart-center/interest-rates/. (7/10/23 through 8/9/23).

Schedule MM-R1

Figure 61. Recent treasury bill rates at the time of AESC 2024's input assumption development

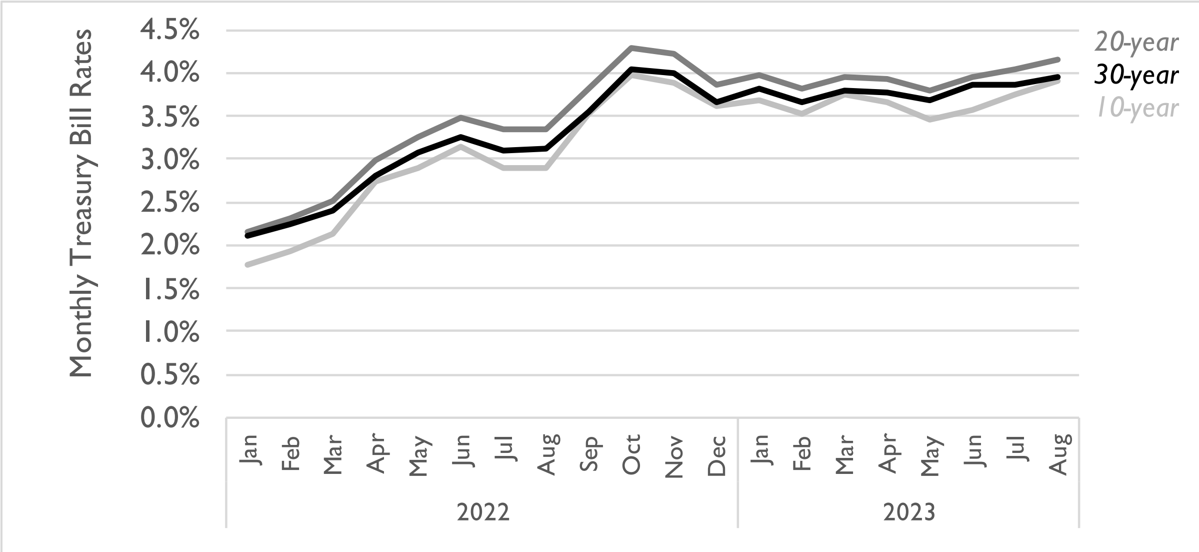

Table 167. Composite nominal rate calculation

Year	Rate	Index	Year	Rate	Index
2024	4.03%	1.000	2040	4.03%	1.883
2025	4.03%	1.040	2041	4.03%	1.958
2026	4.03%	1.082	2042	4.03%	2.037
2027	4.03%	1.126	2043	4.03%	2.120
2028	4.03%	1.171	2044	4.03%	2.205
2029	4.03%	1.219	2045	4.03%	2.294
2030	4.03%	1.268	2046	4.03%	2.387
2031	4.03%	1.319	2047	4.03%	2.483
2032	4.03%	1.372	2048	4.03%	2.583
2033	4.03%	1.427	2049	4.03%	2.687
2034	4.03%	1.485	2050	4.03%	2.795
2035	4.03%	1.545			
2036	4.03%	1.607			
2037	4.03%	1.672			
2038	4.03%	1.739			
2039	4.03%	1.810			

Notes: A nominal rate of 4.03 percent used throughout the period.

AESC 2024 requires the calculation of illustrative levelized avoided costs expressed in 2024 $ for various intervals using the identified real discount rate. Note that the *AESC 2024 User Interface* workbook allows readers of AESC 2024 to input their preferred discount rate to calculate levelized avoided costs.

Schedule MM-R1

It has been suggested that for some purposes it might be more appropriate to use a social discount rate. Exploration of that issue is beyond the scope of this project, but users are encouraged to use whatever discount rate they find most appropriate. See for example the *National Standard Practice Manual*.[438]

The nominal and real discount rates from the 30-year T-Bills are 4.03 percent and 1.74 percent respectively. The resulting 30-year inflation rate is 2.25 percent. The real discount rate is 1.74 percent, which appears reasonable for calculations of levelized costs through periods as long as 30 years. This is higher than the AESC 2021 rate of 0.81 percent and the AESC 2018 rate of 1.34 percent and lower than the AESC 2015 rate of 2.43 percent. We thus rely on a real discount rate of 1.74 percent. Table 168 presents a summary of our findings.

Table 168. Comparison of discount rate projections

	AESC 2015	AESC 2018	AESC 2021	CBO 2023	AESC 2024
Long-term nominal rate	4.36%	3.37%	2.82%	3.80%	4.03%
Source	Composite CBO thru 2024, AEI 2014 thru 2030	Composite of 10- and 30-year Treasury rates.	30 Year T-Bills Jan 2018-Jan 2020	Forecast: 10-year Treasury notes 2024–2033	30 Year T-Bills July–August 2023
Inflation Rate	1.88%	2.00%	2.00%	2.11%	2.25%
Source	Composite CBO thru 2024, AEO 2014 thru 2030	Same as 2018 CBO forecast.	Same as 2020 CBO forecast.	Core PCE Price Index 2024–2033 (January 2023)	Derived from 30 Year T-Bill rates
Resulting long-term real discount rate	2.43%	1.34%	0.81%	1.66%	1.74%

Sources: January 2023 CBO inflation rate is from "The Budget and Economic Outlook: Fiscal Years 2023 to 2033," Congressional Budget Office, January 2023, Table 2-1. Other data sources are as indicated.

438 For more on this topic, see the *National Standard Practice Manual* at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/.

Schedule MM-R1

APPENDIX F: USER INTERFACE

The *AESC 2024 User Interface* is a set of Excel-based documents that allows readers of AESC 2024 to develop avoided costs specific to their counterfactual, region, and year of interest. In addition, this workbook allows users to examine hour-by-hour energy prices and DRIPE values for each reporting region for 2024 through 2050. 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 2060, using the extrapolation methodology described in Appendix A: *Usage Instructions*.

The main purpose of this workbook is to generate avoided costs that are specific to their counterfactual, region, and year of interest. First, users choose the version of the *AESC 2024 User Interface* that is specific to the counterfactual that they would like to use. Separate *AESC 2024 User Interface* files are available for all eight modeled scenarios from AESC 2024. Once selected, users open the *AESC 2024 User Interface* file of their choosing, and proceed to select their region of interest. Selectable regions include all six New England states, as well as five subregions within Connecticut and Massachusetts. Next, users specify the year their program is set to be deployed. Finally, users have the option to modify many other parameters related to costs of carbon, discount rates, transmission and distribution losses, and other variables. For more detail on how to use the *AESC 2024 User Interface*, see the .MP4 recording available on the Synapse website at https://www.synapse-energy.com/aesc-2024-materials.

A secondary 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 2024 User Interface*, users can develop customized costs using the following selectable options:

- **Time period:** The interface provides energy and DRIPE values modeled from 2024 through 2050 and extrapolated through 2060.
- **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.
- **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")

Schedule MM-R1

APPENDIX G: MARGINAL EMISSION RATES AND NON-EMBEDDED ENVIRONMENTAL COST DETAIL

This appendix presents the modeled emission rates for GHGs in the non-electric and electric sectors.

Non-electric emission rates

Table 169 provides GHG emission rates for the various fuels analyzed in this chapter. GHG emissions include CO_2, CH_4, and N_2O. This table defines two separate values for all fuel types that involve some degree of biomass or wood blending. The first value is inclusive of emissions from these sources. The second number (after "or") describes the value assuming that emissions from the biomass portion of the fuel are not counted. This second value is useful in jurisdictions that dictate a zero emissions rate for biomass fuels for accounting purposes.[439,440] Likewise, point-of-combustion emission rates for renewable natural gas and green hydrogen are assumed to be zero. New to AESC 2024, we also include data on upstream emissions rates for each of the fuels (see Table 170). Additional information on emissions rates can be found in a forthcoming appendix. Discussion of emission rates for renewable natural gas and hydrogen can be found in Section 2.3: *New England natural gas market*. Upstream emissions for municipal solid waste (MSW) were estimated using emissions estimates from a 2020 EPA study, which documented GHG emissions in a waste reduction model.[441] MSW upstream emissions were estimated using emissions from waste transportation to a combustion facility. These upstream emissions, primarily based on emissions associated with transportation, were provided in terms of GHG emissions per short ton combusted for a variety of materials found in MSW. We weighted each emission rate by the share of material found in MSW in order to produce a single weighted average value.[442]

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[439] Sterman, J, Siegel, L, and Varga-Rooney, J. 2018. "Does replacing coal with wood lower CO2 emissions? Dynamic lifecycle analysis of wood bioenergy." Environ. Res. Lett. 13 015007. Available at: https://doi.org/10.1088/1748-9326/aaa512.

[440] Rolls, W and Forster, P. 2020. "Quantifying forest growth uncertainty on carbon payback times in a simple biomass carbon model." Environ. Res. Commun. 2 045001. Available at: https://doi.org/10.1088/2515-7620/ab7ff3.

[441] *Documentation for Greenhouse Gas Emission and Energy Factors Used in the Waste Reduction Model (WARM)*. U.S. EPA. November 2020. Available at https://www.epa.gov/sites/default/files/2020-12/documents/warm_background_v15_10-29-2020.pdf.

[442] Guide to the Facts and Figures Report about Materials, Waste and Recycling. U.S. EPA. Accessed December 2023. Available at https://www.epa.gov/facts-and-figures-about-materials-waste-and-recycling/guide-facts-and-figures-report-about#:~:text=Organic%20materials%20such%20as%20paper%20and%20paperboard%2C%20yard,8.8%20percent%3B%20and%20wood%20made%20up%206.2%20percent.

Schedule MM-R1

Table 169. Combustion GHG emission rates for non-electric fuels (lb per MMBtu)

Fuel	CO_2	CH_4	N_2O
Distillate fuel oil	163	0.00661	0.00132
B5 Biofuel	165 or 155	0.00708 or 0.00628	0.00165 or 0.00126
B20 Biofuel	172 or 131	0.00847 or 0.00529	0.00265 or 0.00106
B50 Biofuel	185 or 82	0.01124 or 0.00331	0.00463 or 0.00066
Biodiesel	207 or 0	0.01587 or 0	0.00794 or 0
Kerosene	166	0.00661	0.00132
LPG	136	0.00661	0.00132
RFO	163	0.00661	0.00132
Transportation Diesel	163	0.00661	0.00132
Gasoline	155	0.00661	0.00132
Wood	207 or 0	0.01587 or 0	0.00794 or 0
Wood & Waste	207 or 0	0.01587 or 0	0.00794 or 0
Municipal Solid Waste	200	0.07055	0.00926
Coal	206	0.02425	0.00353
Natural Gas	117	0.00220	0.00022
Renewable Natural Gas	0	0	0
Green Hydrogen	0	0	0

Note: Biofuel rates are based on the fossil fuel fraction.
Sources: EPA GHG Emission Factors Hub, available at https://www.epa.gov/system/files/documents/2023-03/ghg_emission_factors_hub.pdf.

Table 170. Upstream GHG emission rates for non-electric fuels (lb per MMBtu)

Fuel	CO_2	CH_4	N_2O
Distillate fuel oil	32	0.26235	0.00055
B5 Biofuel	31 or 31	0.24950 or 0.24923	0.00079 or 0.00052
B20 Biofuel	27 or 26	0.21096 or 0.20988	0.00153 or 0.00044
B50 Biofuel	19 or 16	0.13389 or 0.13117	0.00299 or 0.00028
Biodiesel	5 or 0	0.00542 or 0	0.00542 or 0
Kerosene	21	0.23369	0.00035
LPG	37	0.26235	0.00057
RFO	25	0.24030	0.00042
Transportation Diesel	32	0.26235	0.00055
Gasoline	42	0.27558	0.00071
Wood	5 or 0	0.00542 or 0	0.00542 or 0
Wood & Waste	5 or 0	0.00542 or 0	0.00542 or 0
Municipal Solid Waste	0.1	0	0.27592
Coal	7	0.88405	0.00022
Natural Gas	27	0.77162	0.00031
Renewable Natural Gas	31	0	0
Green Hydrogen	0	0	0

Note: Biofuel rates are based on the fossil fuel fraction. The RNG emission rate is inclusive of all pollutants and is effectively a CO_2-eq rate. The value shown is an average of the emission rates described in Table 20.
Sources: NYS Statewide GHG Emissions Report Appendix A, available at https://www.dec.ny.gov/docs/administration_pdf/ghgappxclcpaemissfctrs22.pdf; Cambium 2022 Documentation, available at https://www.nrel.gov/docs/fy23osti/84916.pdf.

Electric emission rates

The following tables repeat several of the tables from Section 8.2: *Applying non-embedded costs*. These tables are repeated here for easy reference and comparison with the non-electric emission rates.

Schedule MM-R1

Table 171. Modeled marginal electric sector CO_2 emissions rates (lb per MWh), point of combustion

	Annual Average	Winter		Summer	
		On Peak	*Off Peak*	*On Peak*	*Off Peak*
2024	732	917	758	643	436
2025	732	917	758	643	436
2026	732	917	758	643	436
2027	775	852	813	709	622
2028	775	852	813	709	622
2029	775	852	813	709	622
2030	760	781	722	763	797
2031	760	781	722	763	797
2032	760	781	722	763	797
2033	730	737	650	804	812
2034	730	737	650	804	812
2035	730	737	650	804	812
2036	595	615	537	637	637
2037	595	615	537	637	637
2038	595	615	537	637	637
2039	495	508	449	547	519
2040	495	508	449	547	519
2041	495	508	449	547	519
2042	441	463	399	488	444
2043	441	463	399	488	444
2044	441	463	399	488	444
2045	387	390	374	409	390
2046	387	390	374	409	390
2047	387	390	374	409	390
2048	357	383	343	352	343
2049	357	383	343	352	343
2050	357	383	343	352	343

Notes: We assume all counterfactuals utilize the same marginal emission rates.

Schedule MM-R1

Table 172. Modeled marginal electric sector greenhouse gas emissions rates (lb per MWh)

	Combustion			Upstream		
	CO2	*CH4*	*N2O*	*CO2*	*CH4*	*N2O*
2024	732	0.014	0.001	165	4.742	0.002
2025	732	0.014	0.001	165	4.742	0.002
2026	732	0.014	0.001	165	4.742	0.002
2027	775	0.014	0.001	175	5.021	0.002
2028	775	0.014	0.001	175	5.021	0.002
2029	775	0.014	0.001	175	5.021	0.002
2030	760	0.014	0.001	172	4.928	0.002
2031	760	0.014	0.001	172	4.928	0.002
2032	760	0.014	0.001	172	4.928	0.002
2033	730	0.014	0.001	165	4.731	0.002
2034	730	0.014	0.001	165	4.731	0.002
2035	730	0.014	0.001	165	4.731	0.002
2036	595	0.011	0.001	135	3.857	0.002
2037	595	0.011	0.001	135	3.857	0.002
2038	595	0.011	0.001	135	3.857	0.002
2039	495	0.009	0.001	112	3.214	0.001
2040	495	0.009	0.001	112	3.214	0.001
2041	495	0.009	0.001	112	3.214	0.001
2042	441	0.008	0.001	100	2.865	0.001
2043	441	0.008	0.001	100	2.865	0.001
2044	441	0.008	0.001	100	2.865	0.001
2045	387	0.007	0.001	88	2.536	0.001
2046	387	0.007	0.001	88	2.536	0.001
2047	387	0.007	0.001	88	2.536	0.001
2048	357	0.007	0.001	82	2.338	0.001
2049	357	0.007	0.001	82	2.338	0.001
2050	357	0.007	0.001	82	2.338	0.001

Notes: We assume all counterfactuals utilize the same marginal emission rates. Values are shown for All Hours only; values for all time periods are available in the AESC 2024 User Interface.

Schedule MM-R1

Table 173. Modeled average electric sector CO_2 emissions rates (lb per MWh), point of combustion, Counterfactual #1

	Annual Average
2024	342
2025	342
2026	342
2027	255
2028	255
2029	255
2030	176
2031	176
2032	176
2033	155
2034	155
2035	155
2036	156
2037	156
2038	156
2039	158
2040	158
2041	158
2042	163
2043	163
2044	163
2045	162
2046	162
2047	162
2048	159
2049	159
2050	159

Schedule MM-R1

Table 174. Modeled marginal electric sector heat rates (MMBtu per MWh)

	Annual Marginal
2024	6.14
2025	6.14
2026	6.14
2027	6.51
2028	6.51
2029	6.51
2030	6.39
2031	6.39
2032	6.39
2033	6.13
2034	6.13
2035	6.13
2036	5.00
2037	5.00
2038	5.00
2039	4.16
2040	4.16
2041	4.16
2042	3.71
2043	3.71
2044	3.71
2045	3.27
2046	3.27
2047	3.27
2048	3.01
2049	3.01
2050	3.01

Applied non-embedded costs

Users of AESC 2024 must determine which non-embedded costs are most applicable to their own policy context. For illustrative purposes, Table 175 depicts the electric non-embedded costs assuming the New England marginal abatement cost derived from electric sector technologies, under Counterfactual #1 for Massachusetts (as an example state). Table 176 and Table 177 depict non-electric non-embedded GHG costs, also for marginal abatement costs derived from electric sector technologies in Counterfactual #1. Users of AESC 2024 may utilize the AESC 2024 User Interface to generate analogous tables for each of the non-embedded 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 the following tables are already included in Appendix B. These should not be added, and they are shown here for informational purposes only.

Table 175. Electric sector non-embedded costs in Counterfactual #1, Massachusetts (2024 $ per kWh)

	Wholesale Incremental Non-Embedded GHG Cost of Compliance ($/kWh)			
Year	*Winter Peak*	*Winter Off-Peak*	*Summer Peak*	*Summer Off-Peak*
2024	0.0935	0.0767	0.0645	0.0425
2025	0.0974	0.0800	0.0674	0.0446
2026	0.0979	0.0802	0.0674	0.0444
2027	0.0943	0.0899	0.0782	0.0684
2028	0.0961	0.0916	0.0797	0.0697
2029	0.0973	0.0928	0.0807	0.0706
2030	0.0898	0.0828	0.0877	0.0917
2031	0.0911	0.0840	0.0889	0.0930
2032	0.0923	0.0851	0.0901	0.0942
2033	0.0884	0.0777	0.0967	0.0977
2034	0.0898	0.0790	0.0983	0.0993
2035	0.0908	0.0799	0.0994	0.1004
2036	0.0764	0.0664	0.0793	0.0793
2037	0.0774	0.0673	0.0803	0.0803
2038	0.0781	0.0679	0.0810	0.0810
2039	0.0649	0.0571	0.0702	0.0664
2040	0.0659	0.0579	0.0712	0.0673
2041	0.0668	0.0587	0.0722	0.0682
2042	0.0615	0.0526	0.0649	0.0589
2043	0.0623	0.0533	0.0658	0.0596
2044	0.0632	0.0541	0.0667	0.0605
2045	0.0535	0.0512	0.0562	0.0534
2046	0.0544	0.0520	0.0571	0.0543
2047	0.0553	0.0529	0.0581	0.0552
2048	0.0549	0.0490	0.0504	0.0490
2049	0.0557	0.0497	0.0511	0.0497
2050	0.0564	0.0504	0.0518	0.0504
15-year levelized cost	**0.0905**	**0.0804**	**0.0821**	**0.0760**

Notes: Values are for Counterfactual #1 only. The illustrative values shown here assume a social cost of greenhouse gases using a 2 percent discount rate, and are inclusive of multiple greenhouse gases (CO_2, CH_4, and N_2O) but are not inclusive of upstream emissions. Prices in Massachusetts diverge from other states due to the presence of unique Massachusetts-specific GHG regulations. Other GHG prices, including values for other states or other non-embedded greenhouse gas approaches, can be calculated using the AESC 2024 User Interface. Values shown do not have losses applied.

Schedule MM-R1

Table 176. Non-electric non-embedded GHG costs in Counterfactual #1 (2021$ per MMBtu), for natural gas and fuel oils

	Natural Gas			Fuel oils						
				Resi.	Commercial			Industrial		
	Residential	Commercial	Industrial	*Distillate Fuel Oil*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*	*Distillate Fuel Oil*	*Residual Fuel Oil*	*Weighted Average*
2024	$13.03	$13.03	$13.03	$18.23	$18.23	$18.21	$18.22	$18.23	$18.21	$18.22
2025	$13.28	$13.28	$13.28	$18.58	$18.58	$18.56	$18.58	$18.58	$18.56	$18.57
2026	$13.47	$13.47	$13.47	$18.84	$18.84	$18.82	$18.84	$18.84	$18.82	$18.84
2027	$13.72	$13.72	$13.72	$19.19	$19.19	$19.17	$19.19	$19.19	$19.17	$19.19
2028	$13.97	$13.97	$13.97	$19.54	$19.54	$19.52	$19.54	$19.54	$19.52	$19.54
2029	$14.16	$14.16	$14.16	$19.80	$19.80	$19.79	$19.80	$19.80	$19.79	$19.80
2030	$14.41	$14.41	$14.41	$20.15	$20.15	$20.14	$20.15	$20.15	$20.14	$20.15
2031	$14.66	$14.66	$14.66	$20.51	$20.51	$20.49	$20.50	$20.51	$20.49	$20.50
2032	$14.84	$14.84	$14.84	$20.77	$20.77	$20.75	$20.77	$20.77	$20.75	$20.77
2033	$15.10	$15.10	$15.10	$21.12	$21.12	$21.10	$21.12	$21.12	$21.10	$21.12
2034	$15.35	$15.35	$15.35	$21.47	$21.47	$21.45	$21.47	$21.47	$21.45	$21.47
2035	$15.53	$15.53	$15.53	$21.73	$21.73	$21.71	$21.73	$21.73	$21.71	$21.73
2036	$15.78	$15.78	$15.78	$22.08	$22.08	$22.06	$22.08	$22.08	$22.06	$22.08
2037	$16.04	$16.04	$16.04	$22.44	$22.44	$22.41	$22.43	$22.44	$22.41	$22.43
2038	$16.22	$16.22	$16.22	$22.70	$22.70	$22.68	$22.70	$22.70	$22.68	$22.70
2039	$16.47	$16.47	$16.47	$23.05	$23.05	$23.03	$23.05	$23.05	$23.03	$23.05
2040	$16.72	$16.72	$16.72	$23.40	$23.40	$23.38	$23.40	$23.40	$23.38	$23.40
2041	$16.97	$16.97	$16.97	$23.75	$23.75	$23.73	$23.75	$23.75	$23.73	$23.75
2042	$17.23	$17.23	$17.23	$24.10	$24.10	$24.08	$24.10	$24.10	$24.08	$24.10
2043	$17.48	$17.48	$17.48	$24.45	$24.45	$24.43	$24.45	$24.45	$24.43	$24.45
2044	$17.73	$17.73	$17.73	$24.80	$24.80	$24.78	$24.80	$24.80	$24.78	$24.80
2045	$17.98	$17.98	$17.98	$25.15	$25.15	$25.13	$25.15	$25.15	$25.13	$25.15
2046	$18.23	$18.23	$18.23	$25.51	$25.51	$25.48	$25.50	$25.51	$25.48	$25.50
2047	$18.54	$18.54	$18.54	$25.94	$25.94	$25.92	$25.94	$25.94	$25.92	$25.94
2048	$18.79	$18.79	$18.79	$26.29	$26.29	$26.27	$26.29	$26.29	$26.27	$26.29
2049	$19.04	$19.04	$19.04	$26.65	$26.65	$26.62	$26.64	$26.65	$26.62	$26.64
2050	$19.29	$19.29	$19.29	$27.00	$27.00	$26.97	$27.00	$27.00	$26.97	$26.99
Levelized										
2024-2038	$14.56	$14.56	$14.56	$20.37	$20.37	$20.35	$20.37	$20.37	$20.35	$20.37

Notes: The illustrative values shown here assume a social cost of greenhouse gases using a 2 percent discount rate, and are inclusive of multiple greenhouse gases (CO_2, CH_4, and N_2O) but are not inclusive of upstream emissions. Other GHG prices, including values for other states or other non-embedded greenhouse gas approaches, can be calculated using the AESC 2024 User Interface.

Schedule MM-R1

Table 177. Non-electric non-embedded GHG costs in Counterfactual #1 (2021$ per MMBtu), for fuels other than natural gas and fuel oils

	Other Fuels									
	Residential							Industrial	Transportation	
	Cord Wood	*Pellet*	*Kerosene*	*Propane*	*Biofuel (B5)*	*Biofuel (B20)*	*Biofuel (B50)*	*Kerosene*	*Motor Gasoline*	*Motor Diesel*
2024	$0.00	$0.00	$18.50	$15.19	$17.31	$14.58	$9.11	$18.50	$17.28	$18.20
2025	$0.00	$0.00	$18.86	$15.48	$17.65	$14.86	$9.29	$18.86	$17.61	$18.55
2026	$0.00	$0.00	$19.12	$15.70	$17.90	$15.07	$9.42	$19.12	$17.86	$18.81
2027	$0.00	$0.00	$19.48	$15.99	$18.23	$15.35	$9.59	$19.48	$18.19	$19.16
2028	$0.00	$0.00	$19.83	$16.29	$18.56	$15.63	$9.77	$19.83	$18.52	$19.51
2029	$0.00	$0.00	$20.10	$16.51	$18.81	$15.84	$9.90	$20.10	$18.77	$19.77
2030	$0.00	$0.00	$20.46	$16.80	$19.15	$16.12	$10.08	$20.46	$19.11	$20.12
2031	$0.00	$0.00	$20.81	$17.09	$19.48	$16.40	$10.25	$20.81	$19.44	$20.47
2032	$0.00	$0.00	$21.08	$17.31	$19.73	$16.61	$10.38	$21.08	$19.69	$20.73
2033	$0.00	$0.00	$21.44	$17.60	$20.06	$16.90	$10.56	$21.44	$20.02	$21.08
2034	$0.00	$0.00	$21.79	$17.89	$20.40	$17.18	$10.74	$21.79	$20.35	$21.43
2035	$0.00	$0.00	$22.06	$18.11	$20.65	$17.39	$10.87	$22.06	$20.60	$21.70
2036	$0.00	$0.00	$22.42	$18.41	$20.98	$17.67	$11.04	$22.42	$20.94	$22.05
2037	$0.00	$0.00	$22.77	$18.70	$21.31	$17.95	$11.22	$22.77	$21.27	$22.40
2038	$0.00	$0.00	$23.04	$18.92	$21.56	$18.16	$11.35	$23.04	$21.52	$22.66
2039	$0.00	$0.00	$23.40	$19.21	$21.90	$18.44	$11.52	$23.40	$21.85	$23.01
2040	$0.00	$0.00	$23.75	$19.50	$22.23	$18.72	$11.70	$23.75	$22.18	$23.36
2041	$0.00	$0.00	$24.11	$19.80	$22.56	$19.00	$11.88	$24.11	$22.52	$23.71
2042	$0.00	$0.00	$24.46	$20.09	$22.90	$19.28	$12.05	$24.46	$22.85	$24.06
2043	$0.00	$0.00	$24.82	$20.38	$23.23	$19.56	$12.23	$24.82	$23.18	$24.41
2044	$0.00	$0.00	$25.18	$20.67	$23.56	$19.84	$12.40	$25.18	$23.51	$24.76
2045	$0.00	$0.00	$25.53	$20.97	$23.90	$20.12	$12.58	$25.53	$23.85	$25.11
2046	$0.00	$0.00	$25.89	$21.26	$24.23	$20.40	$12.75	$25.89	$24.18	$25.46
2047	$0.00	$0.00	$26.33	$21.62	$24.65	$20.75	$12.97	$26.33	$24.59	$25.90
2048	$0.00	$0.00	$26.69	$21.92	$24.98	$21.04	$13.15	$26.69	$24.93	$26.25
2049	$0.00	$0.00	$27.05	$22.21	$25.31	$21.32	$13.32	$27.05	$25.26	$26.60
2050	$0.00	$0.00	$27.40	$22.50	$25.65	$21.60	$13.50	$27.40	$25.59	$26.95
Levelized										
2024-2038	$0.00	$0.00	$20.68	$16.98	$19.35	$16.30	$10.19	$20.68	$19.31	$20.34

Notes: The illustrative values shown here assume a social cost of greenhouse gases using a 2 percent discount rate, and are inclusive of multiple greenhouse gases (CO_2, CH_4, and N_2O) but are not inclusive of upstream emissions. Other GHG prices, including values for other states or other non-embedded greenhouse gas approaches, can be calculated using the AESC 2024 User Interface. Values assume an emissions rate of 0 lb greenhouse gases per MMBtu for all components of fuels derived from biomass.

Schedule MM-R1

APPENDIX H: DRIPE DERIVATION

This appendix describes the derivation of 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:

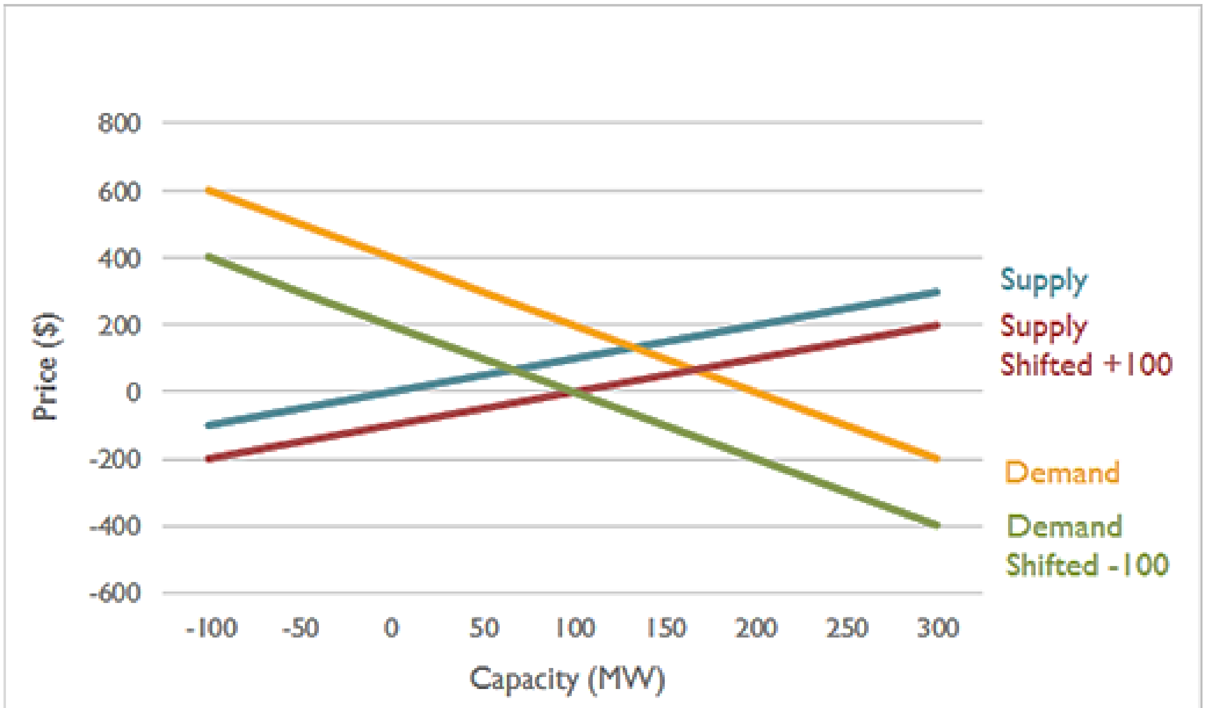
$$b_{demand\ shifted} = b_D - m_D \alpha$$

The shifted Demand function equals:

$$D_{shifted} = b_D - m_D(\alpha + x)$$

Figure 62 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 62. 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 $Price^*$.

Schedule MM-R1

APPENDIX I: MATRIX OF RELIABILITY SOURCES

This appendix documents the studies in Chapter 11: *Value of Reliability*.

Table 178. Matrix of reliability sources

Year	Author	Title	Journal or Source	Document Focus
2022	Midcontinent Independent System Operator, Inc.	Value of Lost Load (VOLL)	Prepared by the Regional Expansion Criteria and Benefits Working Group. Available at https://cdn.misoenergy.org/20200910%20MSC%20Item%2005b%20RAN%20Value%20of%20Lost%20Load%20(IR071)472095.pdf	Reliability Value Assessment – VoLL Methods
2022	Electric Reliability Council of Texas, Inc.	2022 Biennial ERCOT Report on the Operating Reserve Demand Curve	Available at https://www.ercot.com/files/docs/2022/10/31/2022%20Biennial%20ERCOT%20Report%20on%20the%20ORDC%20-%20Final_corr.pdf	Review of operating reserve requirements
2023	Macmillan, M., Wilson, K., Baik, S., Carvallo, J. P., Dubey, A., & Holland, C. A.	Shedding light on the economic costs of long-duration power outages	Report funded by U.S. Department of Energy under Contract NO. DE-AC36-08GO28308. Available at https://eta-publications.lbl.gov/sites/default/files/erss_manuscript_preprint_0.pdf	Reliability Value Assessment (Literature Review)
2018		ICE Calculator	The ICE Calculator was funded by U.S. Department of Energy under Contract NO. DE-AC02-05CH11231. Available at https://icecalculator.com/home	Reliability Value Calculator – VoLL by Sector and Region
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

Schedule MM-R1

Year	Author	Title	Journal or Source	Document Focus
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
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

Year	Author	Title	Journal or Source	Document Focus
2015	Schroder, T., & Kuckshinrichs, W.	*Value of Lost Load: An Efficient Economic Indicator for Power Supply Security? A Literature Review*	Institute of Energy and Climate Research – Systems Analysis and Technology Evaluation (IEK-STE), Forschungszentrum Julich BMbH, Julich, Germany. Available at https://juser.fz-juelich.de/record/279293/files/fenrg-03-00055.pdf	Reliability Value Assessment – VoLL Methods
2015	Sullivan, M.J., Schellenber, J., Blundell, M.	*Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*	LBNL report funded by Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231., LBNL-6941E, January 2015. Available at https://emp.lbl.gov/sites/default/files/lbnl-6941e.pdf	Reliability Value Assessment – VoLL by Sector, Region and Duration
2014	Khujadze, S., Delphia, J.	*A Study of the Value of Lost Load (VOLL) for Georgia*	Report prepared for USAID Hydro Power and Energy Planning Project, Contract Number AID-OAA-I-13-00018/AID-114-TO-13-00006 Deloitte Consulting LLP. Available at https://dec.usaid.gov/dec/content/Detail.aspx?ctID=ODVhZjk4NWQtM2YyMi00YjRmLTkxNjktZTcxMjM2NDBmY2Uy&rID=MzQ5MTg3	Reliability Value Assessment- VoLL Country Studies
2013	Pfeifenberger, J.P., Spees, K.	*Resource Adequacy Requirements: Reliability and Economic Implications*	Report prepared by Brattle for FERC. Available at https://www.ferc.gov/legal/staff-reports/2014/02-07-14-consultant-report.pdf	Reliability Value Assessment - Planning Reserve Margins
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

Year	Author	Title	Journal or Source	Document Focus
2010	Centolella	*Estimates of the Value of Uninterrupted Service for the Mid-West Independent System Operator*	Available at https://sites.hks.harvard.edu/hepg/Papers/2010/VOLL%20Final%20Report%20to%20MISO%20042806.pdf	Reliability Value Assessment – VoLL Midwest Study
2008	Ventyx	*Analysis of "Loss of Load Probability" (LOLP) at Various Planning Reserve Margins*	Available at https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Attachment-2.10-1-LOLP-Study.pdf	Reliability Metrics - LOLP and Planning Reserve
2006	LaCommare, K.H., Eto, J.H.	*Cost of Power Interruptions to Electricity Consumers in the United States*	LBNL-58164, Report funded by U.S. Department of Energy under Contract NO. DE-AC02-05CH11231. Available at https://emp.lbl.gov/sites/all/files/report-lbnl-58164.pdf	Reliability Value VoLL- Annual Total Costs by Sector and Region
2004	LaCammara, K.H., Eto, J.H.	*Understanding the Cost of Power Interruptions to U.S. Electricity Consumers.*	Ernest Orlando LBNL Environmental Energy Technologies Division. LBNL-55718. Report prepared by U.S. Department of Energy under Contract No. DE-AC03-76F00098. Available at https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/Understanding_Cost_of_Power_Interruptions.pdf	Reliability Value Assessment – VoLL by Sector and Duration
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. 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" tabs of the *AESC 2024 User Interface*, which provide 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
- Appendix J tabs are provided for three costing periods: "O" representing original capacity market conditions, which extend through 2027; "S", representing summer capacity market valuations from 2028 through the remainder of the study period; and "W", representing winter capacity market valuations from 2028 through the remainder of the study period.

This appendix is not intended to substitute the more in-depth explanations 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.[443]
- 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).
- These examples ignore price separation. For more information on the actions performed with auctions that feature price separation, see Section 9.3: *Electric capacity DRIPE.*

[443] Massachusetts is chosen as an example because it constitutes roughly half of New England's electricity demand.

Schedule MM-R1

- 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.

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 $960,000 in benefits if the savings persisted for four years.[444]

This calculation works the same in both the original capacity market period, and the new capacity market projected in 2028 and later years. The sole difference is that in the original period, monthly capacity prices are multiplied by 12 months; in the new capacity market periods, monthly capacity market prices are multiplied by however many months exist in the summer and winter seasons (four months and eight months, respectively). If the 10-MW measure in the above example persisted for eight years (four under the old market structure, and four under the new market structure), and the capacity prices were the same throughout ($2 per kW-month in the old structure, and $2 per kW-month for both summer and winter in the new structure), the total benefits would be $1.9 million.

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 is the case with building electrification measures).[445] 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

[444] This is a simplified example. In practice, program administrators typically discount future benefits and apply T&D losses to convert wholesale avoided costs to retail costs. Capacity values also typically differ year-to-year. Similar caveats apply to the subsequent sections.

[445] We note that building electrification measures (such as heat pumps) typically lead to increased capacity costs, rather than savings. For the sake of readability, this appendix refers to savings only. We expect that impacts for measures that cause capacity demand increases (rather than produce capacity demand savings) can be calculated in exactly the same manner.

Schedule MM-R1

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). For years covered in the original capacity market, these benefits begin phasing in five years after a measure is installed. This delay is tied to a lag in between (a) when a measure is installed, (b) when a load regression is made, and (c) when the auction occurs—in the original market, three years after the load forecast is assembled. Because we assume that the future capacity market utilizes a prompt auction, we shift the phase-in of this effect forward three years.

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. For measures with savings that cross the boundary between markets (e.g., a measure installed in 2024 that persist through 2030), we assume that these effects persist in both market types, as both markets are expected to utilize the same load regression in the same way.

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.[446] 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. However, because the switch to the new market structure occurs before the uncleared capacity benefits begin phasing-in, this measure receives benefits

[446] 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. Note that in future capacity market periods, the reserve margin can sometimes be negative (reflecting the design of seasonal ELCCs rather than conventional reserve margins), which can cause this "gross-up" to actually be a de-rating.

associated with future summer capacity prices and winter capacity prices, rather than benefits associated with prices under the current capacity market structure. Finally, because the LFE varies over time, this value changes in each year. As a result, total undiscounted lifetime benefits are $1.7 million.[447]

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 may also be 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 (<u>intra</u>zonal effects) and benefits to consumers outside of the state where the measure is installed (<u>inter</u>zonal 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 each line segment between each auction round.[448] 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.[449]

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

[447] We note that because the phase-in is shifted three years early under the new market structure, measures installed before 2028 may miss out on those benefits that occur in the earliest phase-in years.

[448] 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.

[449] Price shifts may change year-to-year as the corresponding year's capacity price changes position on the supply curve.

Schedule MM-R1

price shift. However, we assume that only a subset of these resources is 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, only the "unhedged" portion of the capacity requirement (i.e., the share that is bought via the capacity market) would be impacted by DRIPE effects.[450]

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 eight years, we find that it produces undiscounted intrazonal DRIPE benefits of $4.2 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 $4.2 million, without discounting. Total cleared capacity DRIPE benefits are the sum of these two values, or $8.4 million. We assume that these effects extend across the market transition year; under the new market, benefits are simply estimated using the new markets' price shifts rather than the old market's price shifts.

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 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.

[450] 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.

Schedule MM-R1

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. As with uncleared capacity, we assume this LFE schedule is shifted forward three years in the new market structure, as we assume a prompt market comes into effect.
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, because there is a phase-in of uncleared capacity DRIPE benefits, no benefits accrue during the years when the current capacity market is active. Instead, they accrue under the load regressions used in the future markets, producing undiscounted intrazonal and internzonal uncleared capacity DRIPE benefits of $3.7 million each. Total uncleared capacity DRIPE benefits are $7.4 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 2024, we estimate this value at $61 per kWh.
- Second, we estimate the change in MWh of reliability benefits per MW 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

Schedule MM-R1

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 an eight-year lifetime), we would expect cleared reliability benefits of about $0.1 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 2024 is $61 per kWh.

- Second, just as with cleared reliability, we estimate the change in MWh of reliability benefits per MW 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. As with uncleared capacity and uncleared capacity DRIPE, we assume this schedule is shifted forward three years in the new market structure, as we assume a prompt market comes into effect.

- 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. This effect is also assumed to shift forward three years under the new market structure.

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:

Schedule MM-R1

- 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 an eight-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 $960,000 in undiscounted cleared capacity benefits and $855,600 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. Because we expect ISO New England's use of the load regressions used for each individual year to be unchanged under the new market structure, we determine that the scaling effects described in Appendix K can be applied to benefits accruing under both the current market structure and the assumed new market structure that is effective in 2028.

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.[451] 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.[452]

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 2024 text
- Cross-references to parts of the main AESC 2024 text
- Several modifications and corrections to the DR calculator

Analytical updates to this document were not scoped within AESC 2021 or AESC 2024; 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. Furthermore, because we do not assume these load forecasting techniques will change under the new market structure (assumed in AESC 2024 to be effective in 2028), we assume that these same values and effects are also applicable to benefits that accrue in the summer season in years in which the new market structure is active. However, we note that this methodology uses the impact of changes in loads on the peak load forecast, assuming that the peak load forecast is a proxy for the amount of capacity that ISO will procure for the region. That has historically been a reasonable proxy, but over time this may become a less accurate assumption as the high-risk hours that determine the ISO's demand for capacity diverge from the peak hours. As a result, the scaling factors described in this section are likely most accurate for measures active in the next one to five years.

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[451] 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.

[452] See original version at https://www.synapse-energy.com/sites/default/files/DR_Coefficient_Calculator%20%282%29.pdf.

Schedule MM-R1

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 under current market rules, though that will change with the implementation of ISO's RCA proposal). 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 uncleared capacity or uncleared capacity DRIPE avoided cost (calculated using the *AESC 2024 User Interface*) and the measure's capacity savings and seasonal coincidence factor to provide the final benefit value.[453]

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

[453] 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.

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 2024 User Interface*.

Background

This issue is specific only to uncleared resources.[454] 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 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.[455] 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.[456] As a result, our analysis reconstructs a proxy ISO New England load forecast. We then use this to quantify the impact of different load reductions over different time periods and under different conditions.

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[454] 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.

[455] 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.

[456] 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.

Schedule MM-R1

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.[457] 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 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).[458, 459] 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

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[457] FCA 12 was conducted in February 2018 and was the most recent FCA conducted at the time of this analysis.

[458] Actual daily peak demand is available from the ISO New England website.

[459] 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

Schedule MM-R1

New England's 2017 Forecast Data spreadsheet for the year. [460, 461] 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.[462]

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 eight weather stations around the region.[463] 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).[464]

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.[465] 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 179.

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[460] 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.

[461] 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.

[462] CELT 2017 Forecast Data File, Tab 1, History, Gross ISO-NE Coincident Summer Peak.

[463] 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/.

[464] 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.

[465] Statmodels. Last accessed March, 10, 2021. *Statsmodels.org*. Available at https://www.statsmodels.org/devel/generated/statsmodels.tsa.statespace.sarimax.SARIMAX.html.

Schedule MM-R1

Table 179. 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.[466]

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 463). 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.[467]

These variables were defined for each July and August day in 2002 through 2016.

466 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.

467 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 unclear why the years 2005 and 2012 featured Boolean flags.

Schedule MM-R1

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.[468] 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.[469]

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°.

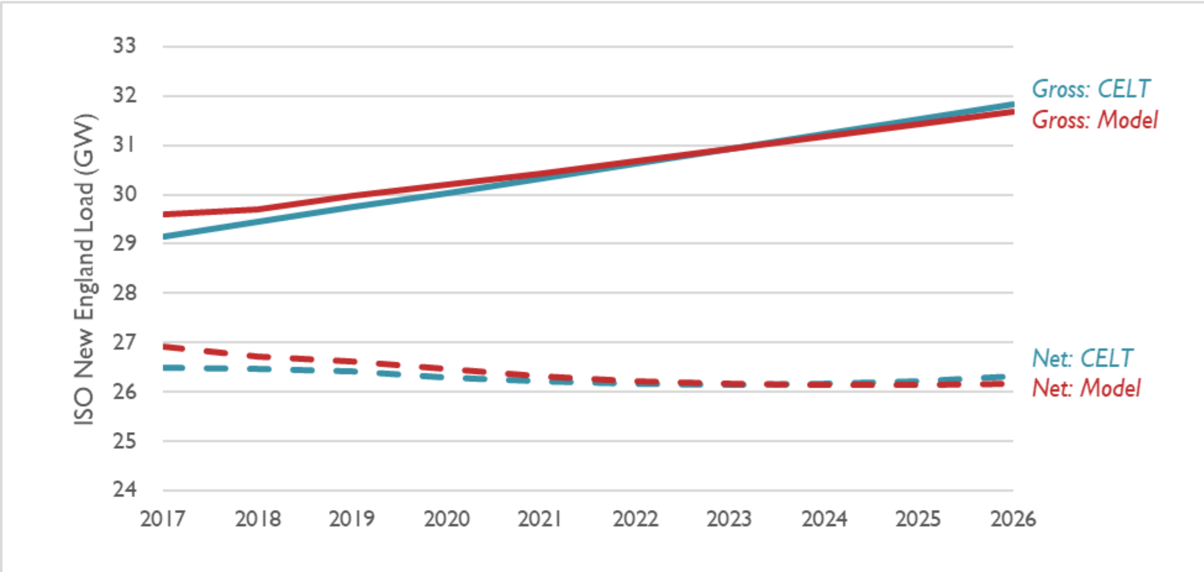
Base forecast benchmarking

Figure 63 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.

[468] 2017 Forecast Data File, Tab 6, Monthly NEL.

[469] Forecast Modeling Procedure for the 2018 CELT, May 1, 2018, p. 6.

Figure 63. 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.

Schedule MM-R1

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.

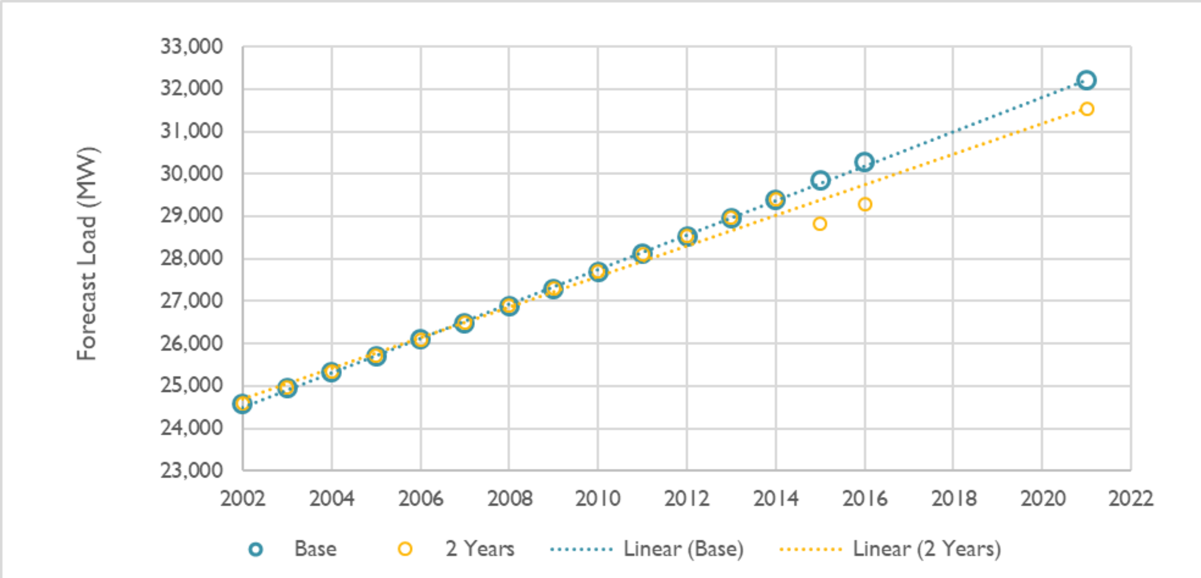
The next four figures show a regression through 15 years of base data. In these examples, we assume a constant 1.5 percent annual growth.[470] In each figure, we show the base historical data, the linear trend line with the base data, the historical data that would have been observed with 1,000 MW reductions 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 64, 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.

[470] 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 2009–2010 Great Recession, it is more difficult to read. We use a simplified example here.

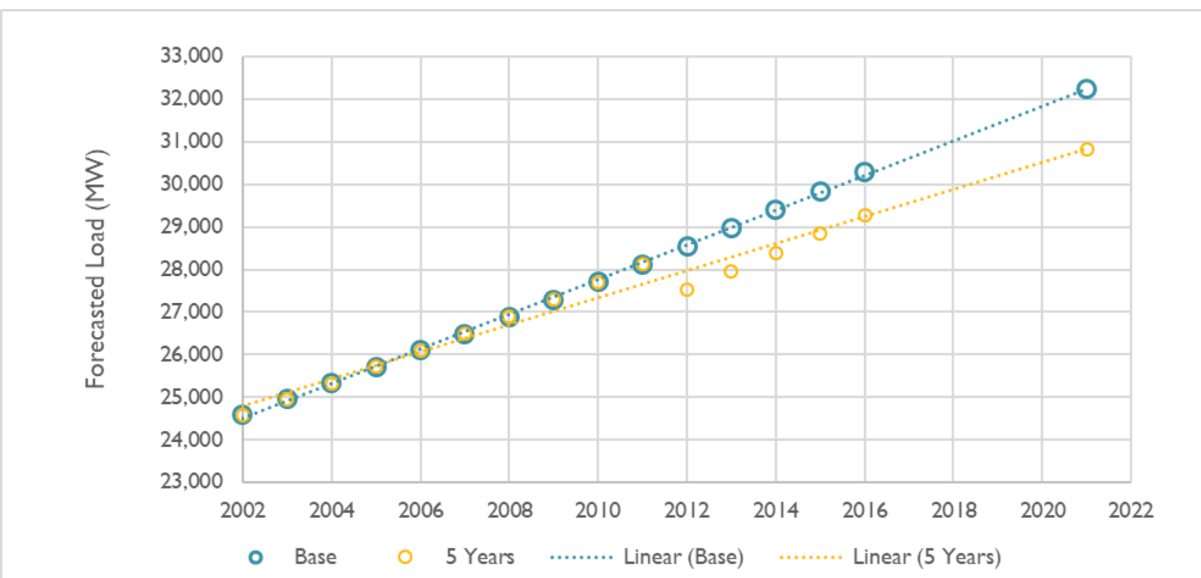
Schedule MM-R1

Figure 64. Effect of two years of demand response on the forecast



Next, Figure 65 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.

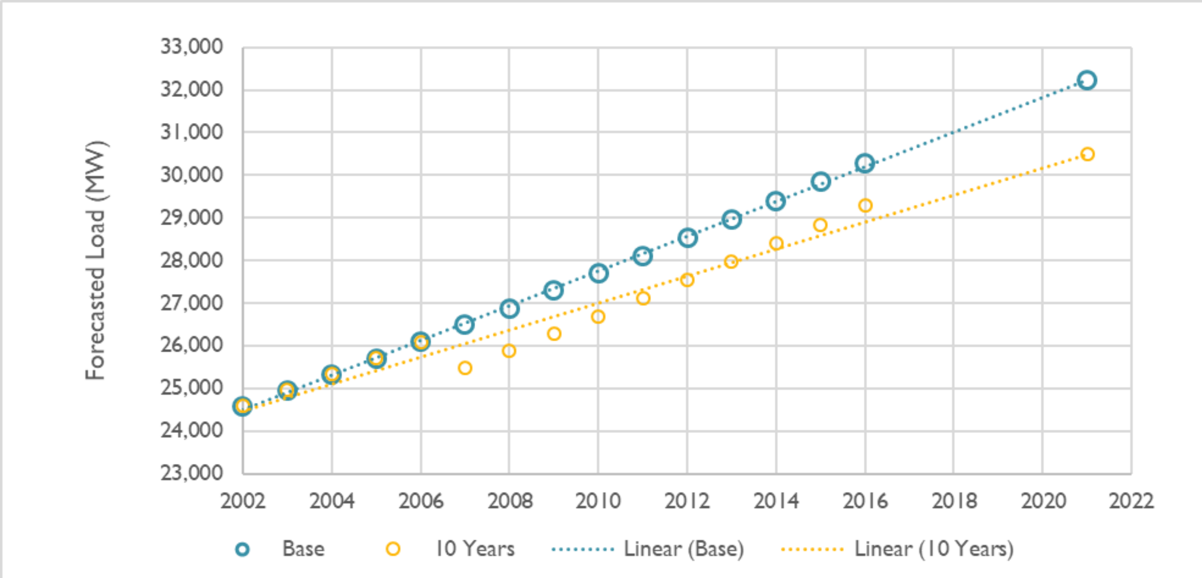
Figure 65. Effect of five years of demand response on the forecast



Third, Figure 66 shows the effects of nine years of demand response, which continues the pattern in Figure 65; the forecast for 2021 would be almost 1,800 MW below the base case.

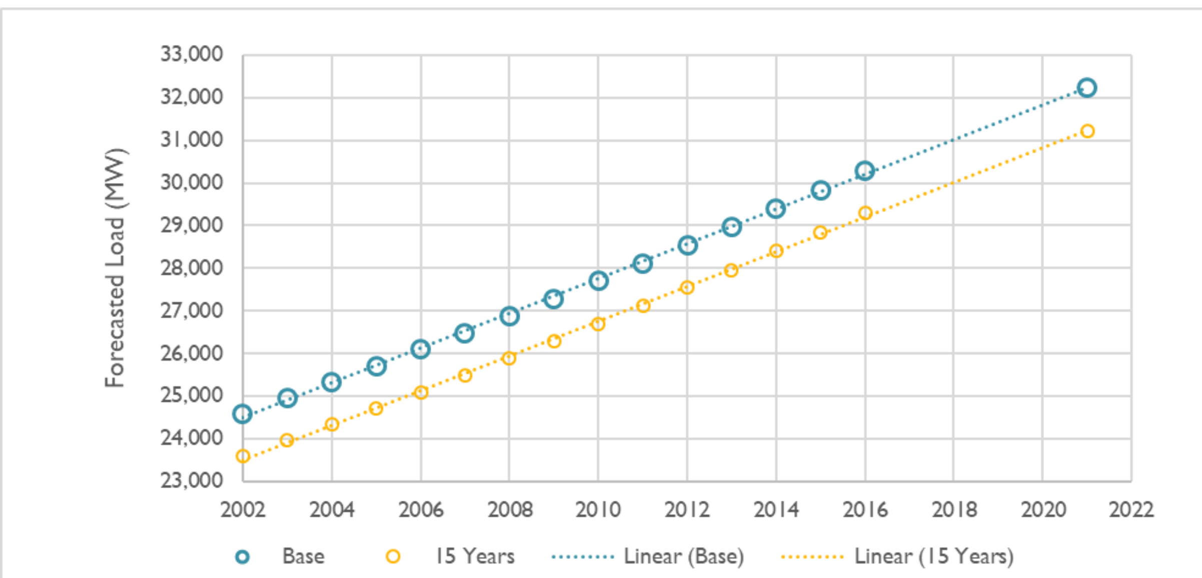
Schedule MM-R1

Figure 66. Effect of nine years of demand response on the forecast



Finally, Figure 67 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 67. 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

Schedule MM-R1

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.

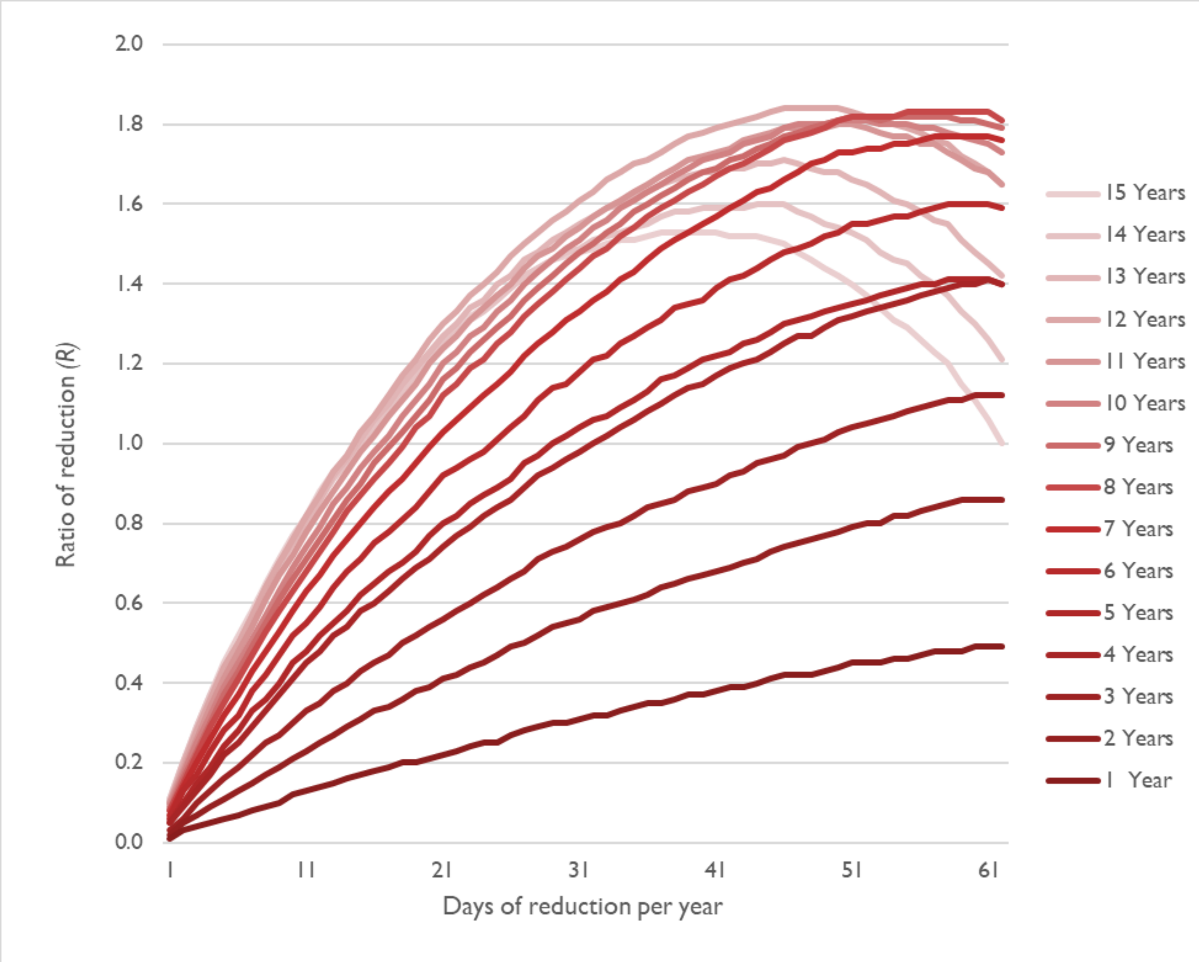
However, the value of *R* did not vary monotonically with respect to either the number of days or the number of years, and *R* could be more than 1.0, as shown in Figure 68.

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.

Schedule MM-R1

Figure 68. Ratio of forecasted load reduction to historical load reduction, various durations

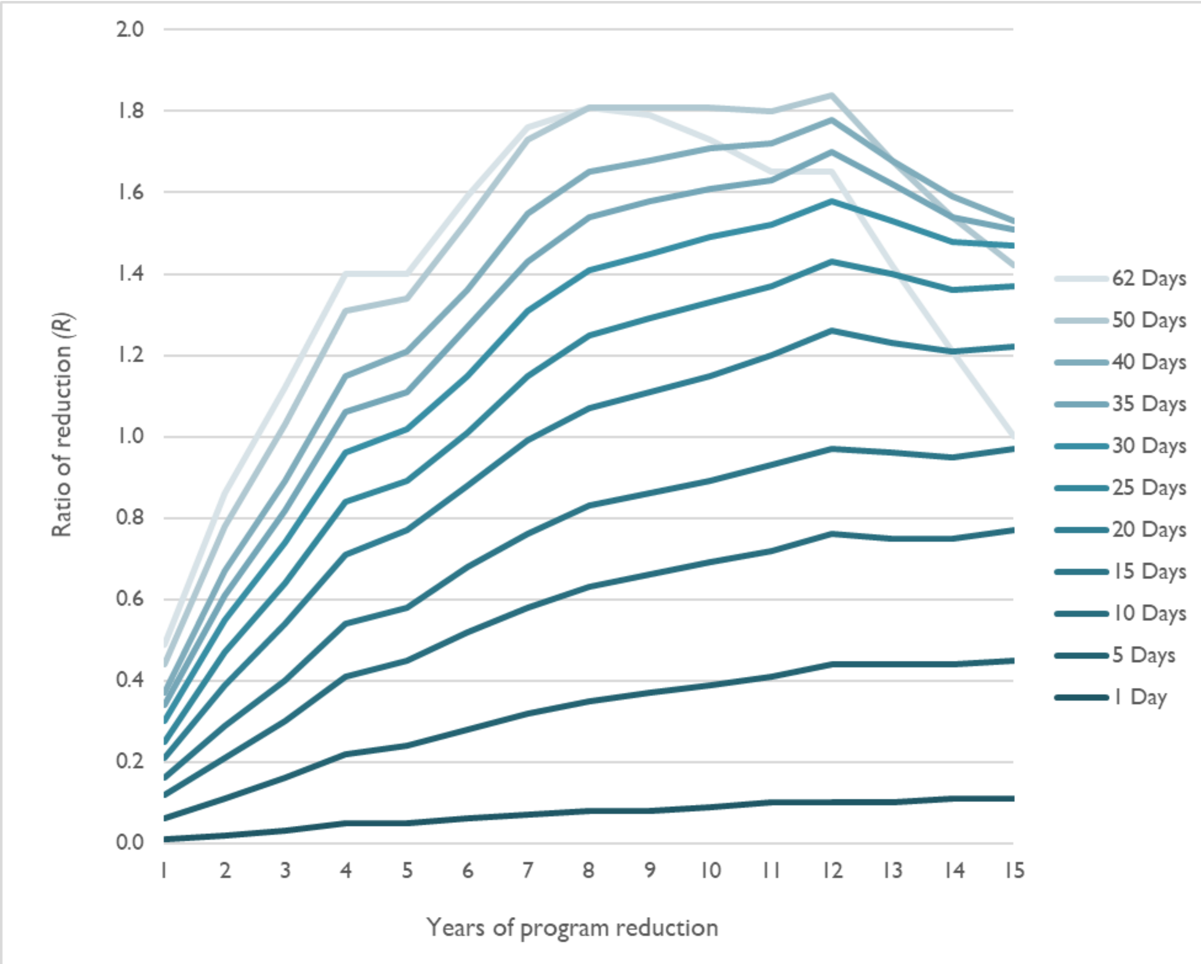


Note: Ratios are shown for 2021 forecasted year.

Figure 69 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 68). For readability, we present only a subset of days, rather than the full 62.

The horizontal axis in Figure 69 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 68 and Figure 69 numerically.

Figure 69. 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 68 and Figure 69 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 10 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.

Schedule MM-R1

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.[471] 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.[472]

Figure 70 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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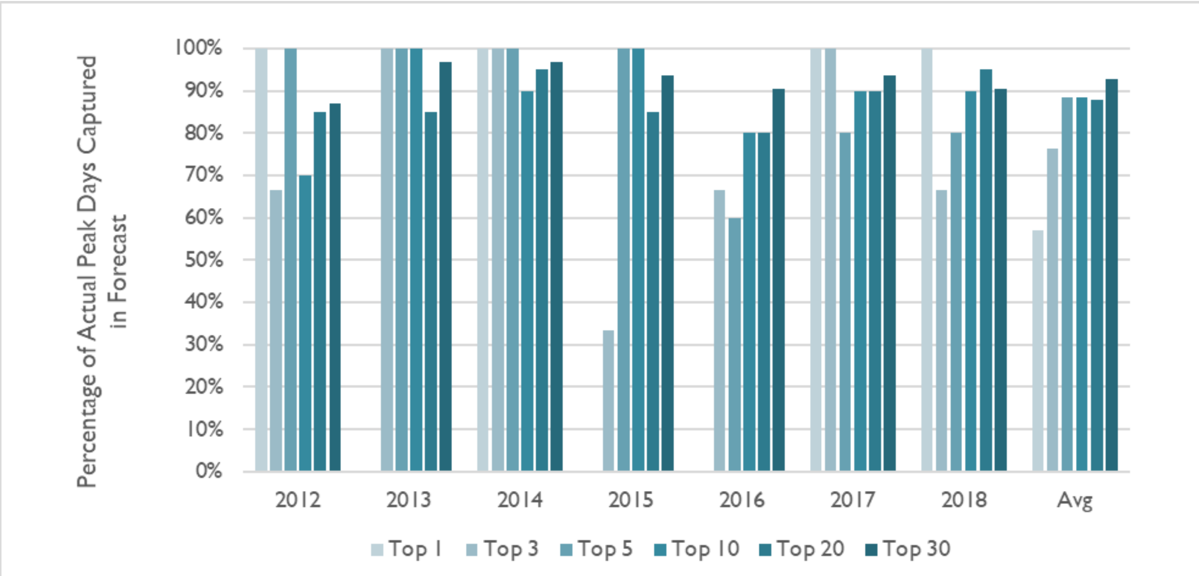
[471] Results are similar, but the curves are less smooth.

[472] 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.

Schedule MM-R1

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 70. Percentage of highest days flagged by day-ahead load forecast, by year



Dispatching demand response, missing some days

Figure 70 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 180 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.

Schedule MM-R1

Table 180. 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 181 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 181. 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 50 event days annually. The detailed pattern of differences between the values shown in Subappendix A and Subappendix 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 15 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 71, Figure 72, and Figure 73, 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.

Schedule MM-R1

Figure 71. Reduction ratio (R) for 1-year program, various numbers of days

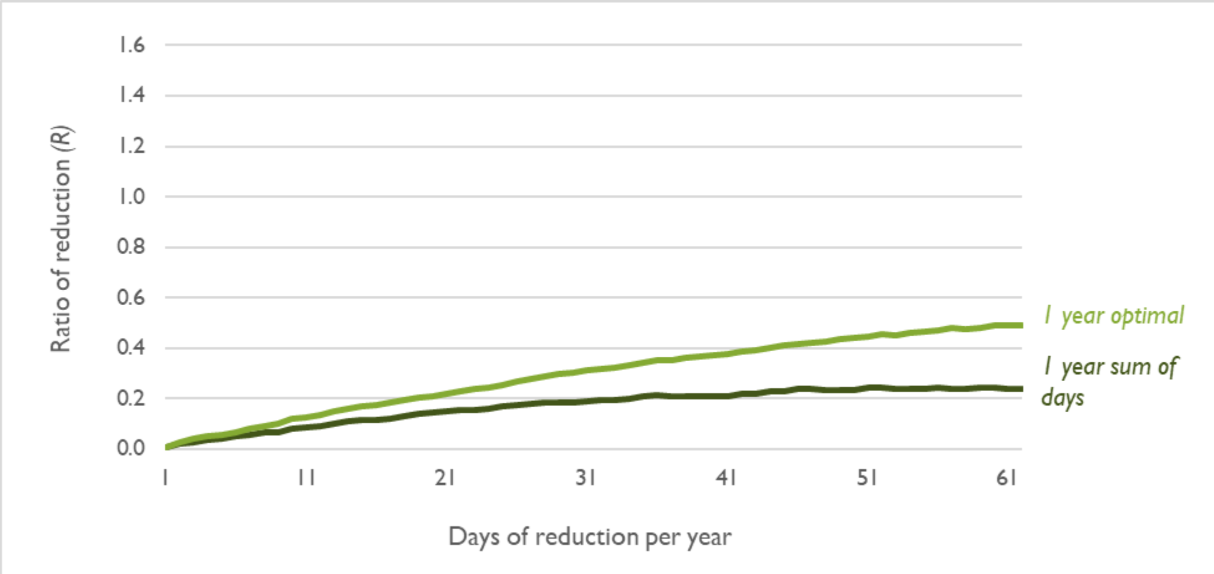


Figure 72. Reduction ratio (R) for 5-year program, various numbers of days

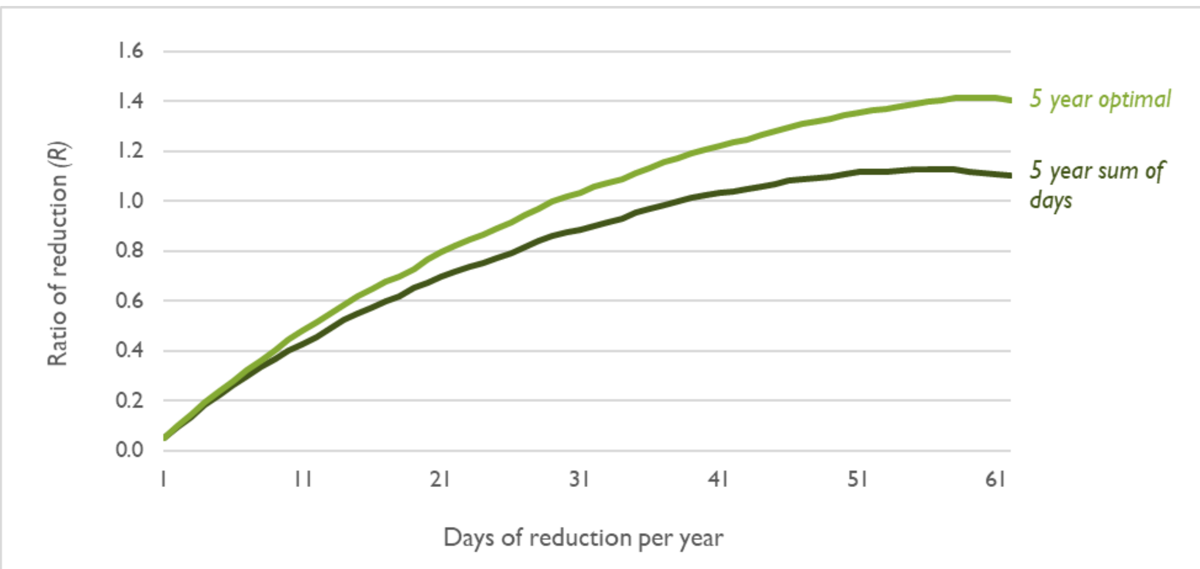
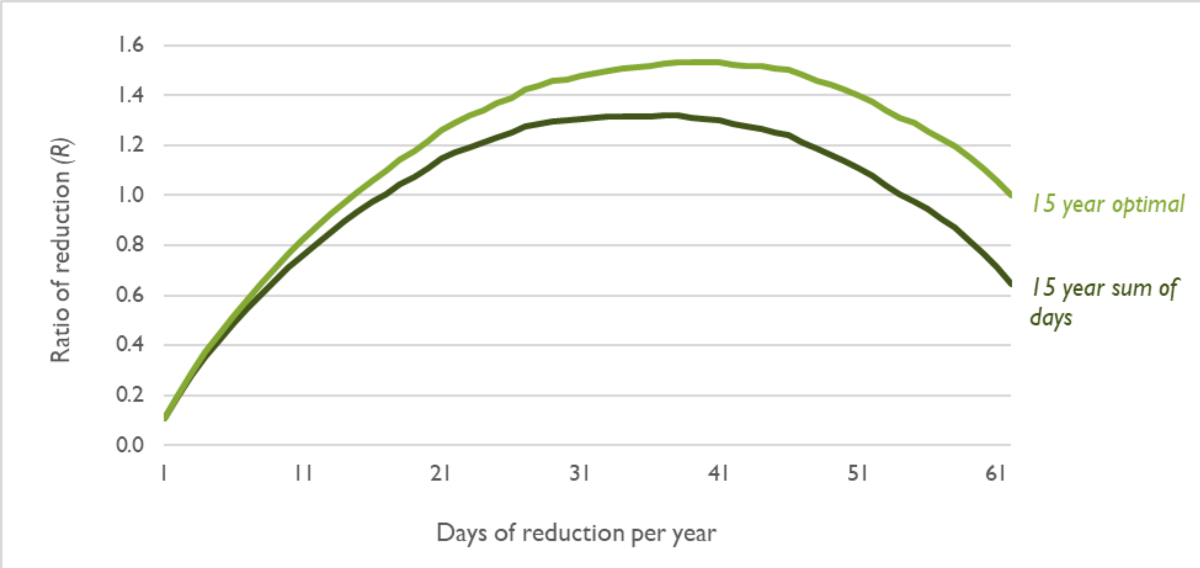


Figure 73. Reduction ratio (R) for 15-year program, various numbers of days



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 184, Subappendix C), and
2. The R value for D days (from Table 182, Subappendix A), minus the sum of the R values for the days less than D that are not in S (from Table 184, 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.

Schedule MM-R1

Subappendix A. Ratio of forecast reduction to load reduction

Table 182 displays the values behind Figure 68 and Figure 69. These values can be applied to uncleared capacity and capacity DRIPE values from AESC 2024 to determine new capacity DRIPE values that are specific to a demand response program.

Table 182. 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

Schedule MM-R1

	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 183 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 183. 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 184 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 184. 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

Schedule MM-R1

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

Schedule MM-R1