July 2020

Distributed Energy Resources

in Connecticut

DRAFT

DRAFT

PREPARED BY:

Connecticut Department of Energy and Environmental Protection

Connecticut Public Utilities Regulatory Authority

TABLE OF CONTENTS

LIST OF ABBREVIATIONS

AC	Alternating current
ACS	U.S. Census Bureau American Community Survey
AEE Institute	Advanced Energy Economy Institute
AEO	U.S. Energy Information Administration Annual Energy Outlook
AESC	Avoided Energy Supply Components study
ANL	Argonne National Laboratory
aMW	Average MW
APEEP	Air Pollution Emission Experiments and Policy analysis models
ASHP	Air source heat pump
BEV	Battery electric vehicle
BRA	PJM Interconnection LLC Base Residual Auction
BTM	Behind-the-Meter
CASPR	Competitive Auctions with Sponsored Policy Resources
CELT	Independent System Operator New England Inc. forecast report of Capacity, Energy, Loads, and Transmission
CGB	Connecticut Green Bank
C&LM	Conservation and Load Management
COBRA	Co-Benefits Risk Assessment
CSO	Capacity Supply Obligation
DC	Direct current
DECD	Department of Economic and Community Development
DEEP	Department of Energy and Environmental Protection
DER	Distributed energy resource
DPDRR	United Illuminating Company Demonstration Project Rate Rider
DRIPE	Demand Reduction Induced Price Effects
EAPSIUR	Estimating Air Pollution Social Impact Using Regression
EDC	Electric distribution company
EE	Energy efficiency
EIA	U.S. Energy Information Administration
EMAAC	PJM Interconnection LLC Eastern Mid-Atlantic Area Council
EPA	U.S. Environmental Protection Agency

ESI	Independent System Operator New England Energy Security Improvements
ESS	Energy storage system
EV	Electric vehicle
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FTM	Front-of-the-Meter
GC3	Governor's Council on Climate Change
GDP	Gross domestic product
Gold Book	New York Independ System Operator Load and Capacity Data report
GWSA	Global Warming Solutions Act
ICE	Interruption Cost Estimate calculator
ICR	Installed Capacity Requirement
IESO	Ontario Independent Electricity System Operator
IPI	Institute of Policy Integrity New York University School of Law
IRP	Integrated Resource Plan
ISO-NE	Independent System Operator New England Inc.
IWG	U.S. federal Interagency Working Group
kWh	Kilowatt hour
LBNL	Lawrence Berkley National Laboratory
LDEV	Light-duty electric vehicle
LDV	Light-duty vehicle
LREC	Low emission renewable energy credit
MW	Megawatt
MWh	Megawatt hour
MAAC	PJM Interconnection LLC Mid-Atlantic Area Council
MADA	Multi-attribute decision analysis
MOPR	Minimum Offer Price Rule
MRI	Marginal Reliability Impact
NARUC	National Association of Regulatory Utility Commissioners
NECEC	New England Clean Energy Connect
NPV	Net present value

NREL	National Renewable Energy Laboratory
NSPM	National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and maintenance
OSW	Offshore wind
PDR	Passive demand response
PfP	Pay for Performance
PG&E	Pacific Gas and Electric
PHEV	Plug-in hybrid electric vehicle
PJM	PJM Interconnection LLC
PURA	Connecticut Public Utilities Regulatory Authority
PV	Photovoltaic
RGGI	Regional Greenhouse Gas Initiative
RPV	Rooftop photovoltaic
RSIP	Residential Solar Investment Program
RSP	Regional System Plan
RTO	Regional transmission organization
RTR	Renewable technology resource
SAM	National Renewable Energy Laboratory System Advisor Model
SCC	Societal Cost of Carbon
SCEF	Shared Clean Energy Facility
Synapse	Synapse Energy Economics, Inc.
TCI	Transportation Climate Initiative
UC	Use Case
UI	The United Illuminating Company
UPV	Utility photovoltaic
VIEC	Vermont Energy Investment Corporation
WIND	National Renewable Energy Laboratory Wind Integration National Dataset toolkit
ZREC	Zero emission renewable energy credit

I. INTRODUCTION

On June 28, 2019, Governor Lamont signed Public Act 19-35, An Act Concerning a Green Economy and Environmental Protection (PA 19-35).[1] Section 6 of PA 19-35 directs the Department of Energy and Environmental Protection (DEEP) and the Public Utilities Regulatory Authority (PURA or Authority; collectively, Agencies) to:

> On or before July 1, 2019…initiate a proceeding to jointly study the value of distributed energy resources. On or before July 1, 2020, [DEEP] and [PURA] shall jointly report the findings of such study, in accordance with the provisions of section 11-4a of the general statutes, to the joint standing committee of the General Assembly having cognizance of matters relating to energy.

Pursuant to Section 6 of Public Act 19-35, the Agencies initiated Docket No. 19-06-29, DEEP and PURA Joint Proceeding on the Value of Distributed Energy Resources, on June 24, 2019, to serve as the administrative record for the Agencies' joint study on the value of Distributed Energy Resources (DERs) in Connecticut (Study). Herein, DEEP and PURA provide the Agencies' joint report on the Study.

The Study provides a high-level analysis of the benefits different DERs provide to Connecticut, as well as a quantification of those value categories. The Study provides valuable information to inform future proceedings at both DEEP and PURA, where further analysis of the costs and benefits of various DERs will result. The analysis does not include a detailed quantification of every value category that DERs may provide;[2] rather, the Study focuses on quantifying those value categories most aligned with state policy, as discussed in subsequent sections. Moreover, as explained more fully below, the Study does not include the ratepayer-funded costs of various DERs, nor the costs or benefits that accrue solely to participants who adopt DERs. While not all DER value categories are quantified in the Study, the Agencies provide a discussion of the value categories not explicitly quantified, including examples of quantification from other studies or jurisdictions, in order to provide a comprehensive report.

Further, the Agencies observe that the Study results are not intended to serve as a cap on either the type of benefit categories, or the monetary value of such benefits, that DERs may ultimately deliver across the state. On the contrary, the Agencies acknowledge throughout the Study the limitations of currently available data and certain methodologies, while also making clear that such additional benefits, while unquantified at this time, do exist. Further investigation of the types and magnitude of benefits that DERs provide, beyond what is quantified herein, is scheduled for consideration in numerous subsequent proceedings before the Agencies, including the proceedings before PURA to establish renewable energy tariffs subject to Section 3

[1] Public Act 19-35, An Act Concerning a Green Economy and Environmental Protection, dated June 28, 2019, p. 17, https://www.cga.ct.gov/2019/ACT/pa/pdf/2019PA-00035-R00HB-05002-PA.pdf.

[2] The DER value categories evaluated for the Study are discussed in subsequent sections. Note that other studies or resources also define such value categories as "value streams" or "value stacks."

of Public Act 19-35,[3] as well as Docket Nos. 17-12-03RE07, 17-12-03RE08, and 17-12-03RE09 as part of the Equitable Modern Grid Framework,[4] and within the Conservation and Load Management (C&LM) Plan process DEEP oversees pursuant to Conn. Gen. Stat. Section 16-245m and the Integrated Resources Plan developed by DEEP pursuant to Conn. Gen. Stat. Section 16a-3a. The Agencies pledge their resources to the continued exploration of the benefits of DERs and how to optimize those benefits in those proceedings and others, during the course of which the Agencies intend to seek out and promote further conversation regarding the potential expansion on the DER benefits baseline articulated by the Study. Simply put, the Agencies are not bound to consider only those benefits categories quantified and described in the Study. The valuation of DERs in the state must be a living resource that evolves over time to recognize additional benefit categories and quantification methodologies as they become available.

Lastly, and most importantly, the Agencies wish to express a firm commitment to the sustained, orderly development of Connecticut's clean energy economy and to meeting the State's decarbonization goals, defined in Section 22a-200a of the Connecticut General Statutes (Conn. Gen. Stat.), as expeditiously and cost-effectively as possible. While this study will aid in that pursuit, it is by no means the only vehicle to achieve that end. Both Agencies have underway expansive bodies of work to ensure the continued and sustained deployment of clean energy in the state, and have plans to expand that work to ensure that Connecticut fully capitalizes on the benefits of renewable energy and DERs, specifically.

VALUING DISTRIBUTED ENERGY RESOURCES

It is the policy of the State to: "(1) conserve energy resources by avoiding unnecessary and wasteful consumption;…(3) develop and utilize renewable energy resources, such as solar and wind energy, to the maximum practicable extent; (4) diversify the state's energy supply mix;…(6) assist citizens and businesses in implementing measures to reduce energy consumption and costs;…and, (9) when available energy alternatives are equivalent, give preference for capacity additions first to conservation and load management."[5]

---

[3] *See*, Docket No. 20-07-01, Notice of Proceeding, dated June 30, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/83acaabcb4ea8310852585970080dfa9?OpenDocument.

[4] *See*, PURA, Connecticut Public Utilities Regulatory Authority Announces Landmark Equitable Modern Grid Framework, dated October 3, 2019, https://portal.ct.gov/PURA/Press-Releases/2019/Connecticut-Public-Utilities-Regulatory-Authority-Announces-Landmark-Equitable-Modern-Grid-Framework. *See also*, Docket No. 17-12-03RE07, Notice of Proceeding, dated June 29, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/5f58a655663f45c285258596005c9791?OpenDocument. *See also*, Docket No. 17-12-03RE08, Notice of Proceeding, dated June 29, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/ef7447ed45877f1c85258596005fde06?OpenDocument. *See also*, Docket No. 17-12-03RE09, Notice of Proceeding, dated June 30, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/8300f6897dad69fe852585970080c190?OpenDocument.

[5] Section 16a-35k of the Connecticut General Statutes (Conn. Gen. Stat.).

Connecticut has consistently valued DERs[6] through the establishment and expansion of policies and incentive structures to support their deployment. Such examples include the initial net metering tariff authorized in Public Act 98-28, An Act Concerning Electric Restructuring,[7] as well as the creation of incentives for DERs through the Residential Solar Investment Program (RSIP) and the low and zero emission renewable energy credit (LREC/ZREC) program established in Public Act 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future.[8] The State continued to support DERs deployed through these program by expanding the corresponding program caps in Public Acts 15-194, 16-196, 17-144, 18-50, and 19-35. In addition, the State maintains a robust C&LM Plan that has encouraged the adoption and deployment of energy efficiency and demand response measures dating back to its establishment in Public Act 98-28, with a goal of reducing energy consumption by 1.6 million MMBtu, or the electric equivalent, each year.[9]

While past legislative action demonstrates that Connecticut values DERs, the Study provides an analytical estimate of benefits DERs provide to the state that may not have been previously quantified, which may inform future policy development, particularly as the State plans its pathway to achieve a 100 percent zero carbon electric sector by 2040, as charged in Governor Lamont's Executive Order No. 3.[10]

Understanding the value of different DER technologies may help establish deployment metrics as one of many policy mechanisms designed to achieve a zero carbon electric sector. However, understanding the value of DERs is separate and distinct from the determination of necessary and appropriate compensation levels needed to incentivize the identified level of deployment. Principles of compensation structuring are fundamentally different from the valuation principles primarily discussed in the Study. This distinction is important in framing the purpose of the Study.[11]

---

[6] *See*, Conn. Gen. Stat. § 16-1 (a)(49): "'Distributed energy resource' means any (A) customer-side distributed resource or grid-side distributed resource that generates electricity from a Class I renewable energy source or Class III source, and (B) customer-side distributed resource that reduces demand for electricity through conservation and load management, energy storage system which is located on the customer-side of the meter or is connected to the distribution system or microgrid."

[7] Public Act 98-28, An Act Concerning Electric Restructuring, dated April 29, 1998, Section 43, https://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm.

[8] Public Act 11-80, An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future, dated July 1, 2011, Section 106-110, https://www.cga.ct.gov/2011/act/pa/pdf/2011PA-00080-R00SB-01243-PA.pdf.

[9] Public Act 98-28, An Act Concerning Electric Restructuring, dated April 29, 1998, Section 33, https://www.cga.ct.gov/ps98/Act/pa/1998PA-00028-R00HB-05005-PA.htm. Public Act 18-50, An Act Concerning Connecticut's Energy Future, dated May 24, 2018, Section 9, https://www.cga.ct.gov/2018/ACT/pa/pdf/2018PA-00050-R00SB-00009-PA.pdf.

[10] Governor Ned Lamont, Executive Order No. 3, dated September 3, 2019, https://portal.ct.gov/-/media/Office-of-the-Governor/Executive-Orders/Lamont-Executive-Orders/Executive-Order-No-3.pdf.

[11] *See*, John Shenot, The Regulatory Assistance Project, Quantifying and Maximizing the Value of Distributed Energy Resources, p. 17, https://www.raponline.org/wp-content/uploads/2020/05/rap_shenot_der_valuation_idp_orpuc_2020_may_08.pdf.

STUDY PRINCIPLES

The Agencies utilized the National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources (NSPM)[12] to guide the development of the Study. Specifically, the NSPM guided the Agencies' development of the initial list of DER value categories included in the Notice of Request for Written Comments dated August 7, 2019,[13] and, along with stakeholder input, helped determine which DER value categories were quantified and which value categories were included, but not quantified, in the Study. The NSPM also provided a framework via the Resource Value Framework Steps for the internal development of the Study. A discussion of the principles contained within the NSPM that generally guided the Study follows.

Policy Goals

The central feature of the Resource Value Framework laid out in the NSPM is the concept that electric system studies should simultaneously reflect the perspective of the utilities, program participants, and society at-large via a "regulatory perspective" based on the jurisdiction's overarching policy aims. This perspective "reflects the objective of providing customers with safe, reliable, low-cost energy services, while meeting a jurisdiction's other applicable policy goals and objectives."[14] This appeal to "other applicable policy goals" reflects the recognition that energy systems do not exist in isolation, but instead have important impacts on broader social and environmental systems.

Symmetry

The NSPM emphasizes that states should take pains to handle concepts symmetrically, to "ensure that the test includes all costs and all benefits associated with each category of impacts. If some costs are excluded, the framework will be inappropriately biased …; if some benefits are excluded, the framework will be inappropriately biased …"[15]

Hard-to-Quantify Impacts

The NSPM emphasizes that "costs and benefits that are relevant to a jurisdiction's applicable policy goals and that can reasonably be assumed to be real and substantial should not be excluded or ignored because they are difficult to quantify and monetize." It notes that "[u]sing 'best available' information to approximate

---

[12] National Efficiency Screening Project, National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, dated 2017, https://nationalefficiencyscreening.org/national-standard-practice-manual/. Also, the National Efficiency Screening Project is developing a manual for DERs, *See*, National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources: Project Overview, dated May 2020, https://nationalefficiencyscreening.org/wp-content/uploads/2019/06/NSPM-for-DERs.pdf.

[13] Notice of Request for Written Comments (Written Comments #1), dated August 7, 2019, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/9b11e97ca52a77e58525844f006f7272/$FILE/Written%20Comments%20%231%20FINAL.docx.

[14] National Efficiency Screening Project, National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, dated 2017, p. ix, https://nationalefficiencyscreening.org/national-standard-practice-manual/.

[15] *Id.*, p. 31.

hard-to-quantify impacts is preferable to assuming that those costs and benefits do not exist or have no value." These approximations can be based on jurisdiction-specific studies, studies from other jurisdictions, or other proxies. This guidance is especially germane for non-energy benefits of DERs, which include health and environmental impacts.[16]

Forward-Looking Analysis and Transparency

The NSPM states that the "[a]nalysis of the impacts of resource investments should be forward looking, capturing the difference between costs and benefits that would occur over the life of the subject resources as compared to the costs and benefits that would occur absent the resource investments." The NSPM also clarifies that a central pillar of any analysis is that it is "completely transparent, and should fully document all relevant inputs, assumptions, methodologies, and results."[17]

State Policy Goals

Step 1 of the Resource Value Framework is to "[i]dentify and articulate the jurisdiction's applicable policy goals." Conn. Gen. Stat. 22a-2d(a) explicitly states the energy policy goals of both DEEP and PURA:

> [DEEP] shall have the following goals: (1) Reducing rates and decreasing costs for Connecticut's ratepayers, (2) ensuring the reliability and safety of our state's energy supply, (3) increasing the use of clean energy and technologies that support clean energy, and (4) developing the state's energy-related economy. For the purpose of environmental protection and regulation, [DEEP] shall have the following goals: (A) Conserving, improving and protecting the natural resources and environment of the state, and (B) preserving the natural environment while fostering sustainable development…[PURA] shall promote policies that will lead to just and reasonable utility rates.

Conn. Gen. Stat. § 22a-200a articulates the State's climate goals, which were first outlined in Public Act 08-98,[18] also known as the Global Warming Solutions Act (GWSA):

> (1) Not later than January 1, 2020, to a level at least ten percent below the level emitted in 1990;
> (2) Not later than January 1, 2030, to a level at least forty-five percent below the level emitted in 2001; and
> (3) Not later than January 1, 2050, to a level at least eighty percent below the level emitted in 2001.

Beyond Conn. Gen. Stat. § 22a-200a, both Governor Ned Lamont and former Governor Dannel Malloy have prioritized for Connecticut the need to address climate change, through the establishment and

---

[16] *Id.*, p. 7-8; 11-12; 33; 59-62.
[17] *Id.*, p. ix.
[18] Public Act 08-98, An Act Concerning Global Warming Solutions, dated June 2, 2008, https://www.cga.ct.gov/2008/ACT/PA/2008PA-00098-R00HB-05600-PA.htm.

expansion of the scope of the Governor's Council on Climate Change (GC3), first in Governor Malloy's Executive Order No. 46[19] and subsequently in Governor Lamont's Executive Order No. 3.[20]

Additionally, elements of Public Acts 11-80, 15-194, and 19-71, among others, clearly demonstrate that in-state economic development (*i.e.* the sustained, orderly development of Connecticut's green economy) is an energy policy objective of the State. Lastly, elements of Public Acts 12-148, 13-239, and 18-82, as well as Governor Malloy's Executive Order No. 50 and Governor Lamont's Executive Order No. 3,[21] among others, demonstrate that resilience – particularly climate resilience – is an energy policy priority of the State.[22]

DER VALUE CATEGORIES

Based on the public policy objectives outlined above, the Agencies identified the following DER value categories for inclusion in the Study: (1) wholesale electric system costs and benefits, including transmission impacts; (2) emissions-related climate benefits; (3) emissions-related local health benefits; (4) macroeconomic costs and benefits; (5) distribution system costs and benefits; (6) resilience benefits; and (7) other health and environmental benefits.

To the extent possible, the Agencies endeavored to quantify the value attributable to DERs located in Connecticut of each category identified above, prioritizing the quantification of value categories in the order listed.[23] Any value category or subcategory not specifically quantified in the Study is discussed and quantified at least in part, where possible, as the NSPM principles dictate and as shown in Table 1.

Table 1 lists the DER value categories and subcategories considered in the Study, identifying which subcategories were quantified and which were qualitatively discussed. For the purposes of Table 1, DER value categories (1), (5), and (6) are included under "Electric System Impacts," while value categories (2), (3), (4), and (7) are included under "Societal Impacts."

---

[19] Governor Dannel Malloy, Executive Order No. 46, dated April 22, 2015, https://portal.ct.gov/-/media/DEEP/climatechange/EO46ClimateChangepdf.pdf.

[20] Governor Ned Lamont, Executive Order No. 3, dated September 3, 2019, https://portal.ct.gov/-/media/Office-of-the-Governor/Executive-Orders/Lamont-Executive-Orders/Executive-Order-No-3.pdf.

[21] Governor Dannel Malloy, Executive Order No. 50, dated October 26, 2015, https://portal.ct.gov//-/media/94273BD61AD24C63B5B07A86638CB68E.pdf. Governor Lamont, Executive Order No. 3, dated September 3, 2019, https://portal.ct.gov/-/media/Office-of-the-Governor/Executive-Orders/Lamont-Executive-Orders/Executive-Order-No-3.pdf.

[22] For additional, relevant public policy, *See*, DEEP, Connecticut Legislation and Executive Orders on Climate, dated September 2019, https://portal.ct.gov/DEEP/Climate-Change/Connecticut-Legislation--Executive-Orders-on-Climate.

[23] The Agencies believe that the order of the DER value categories listed above most accurately represents the State's policy priorities based on the information presented in Section I. of the Study. The Agencies recognize and appreciate that such interpretation is subjective. The order in which these categories are listed was used on a limited basis to direct the Agencies' initial efforts and internal processes for the Study.

Table 1: DER Value Categories Included in Study

Electric System Impacts				
Generation	**Avoided Energy Generation**	**Quantified**	Section II.	Avoided MWhs; avoided energy cost ($/kWh)
	Energy Demand Reduction Induced Price Effects (DRIPE)	**Quantified**	Section II.	Avoided energy DRIPE cost ($/kWh)
	Avoided Generation Capacity	**Quantified**	Section II.	Avoided MWs; avoided capacity cost ($/kWh)
	Capacity DRIPE	**Quantified**	Section II.	Avoided capacity DRIPE cost ($/kWh)
	Avoided Emissions Compliance	**Quantified**	Appendix A.	Implicit in avoided energy costs
	Ancillary Services Avoided + Provided	**Qualitatively Discussed**	Section II.	-
Transmission + Distribution	**Avoided T+D Line Losses**	**Quantified**	Section III. + Appendix B.	Cost impacts included in avoided energy costs; see Appendix B. for Use Case specific details
	Avoided Transmission Capacity	**Quantified**	Section II.	Qualitatively discussed; quantification estimated
	Avoided Distribution Capacity	**Quantified**	Section III.	Qualitatively discussed; quantification estimated
	Avoided Distribution O+M	**Qualitatively Discussed**	Section III.	-
	Avoided Distribution Outages / Reliability	**Qualitatively Discussed**	Section III.	-
	Distribution Voltage + Power Quality	**Qualitatively Discussed**	Section III.	-
	Resilience Benefits	**Qualitatively Discussed**	Section III.	-
Cost	**Integration Costs**	**Qualitatively Discussed**	Section III.	Indicative costs included; tangential to Study scope
	Program + Ratepayer Costs	**Not Included**	N/A	Outside the Study scope, see below
Societal Impacts				
Climate and Local Health Benefits	**Avoided Emissions (CO_2, NOx, SO_2, and $PM_{2.5}$)**	**Quantified**	Section II. + Section III.	Climate and local health benefit ($/kWh); additional discussion in Section III.
Other Societal Impacts	**Macroeconomic Costs + Benefits**	**Quantified**	Section III.	Approaches from other studies included; some costs and benefits calculated
	Other Environmental + Health Benefits	**Qualitatively Discussed**	Section III.	-

STUDY PURPOSE AND SCOPE

The purpose of the Study is to inform ***future*** policies and program designs that incentivize the deployment of DERs.[24] As such, the Study focuses primarily on identifying, quantifying, and discussing the benefits that various DERs can provide to all electric ratepayers and citizens of Connecticut, as a whole. More specifically, the Study evaluates the value that various DERs provide by adding (1) the benefits delivered by DERs through the electric system to all ratepayers, with (2) the societal benefits delivered by DERs to all Connecticut citizens, irrespective of who pays or benefits.[25] The Study does not evaluate the ratepayer cost of deploying DERs,[26] but rather the benefits the deployment of DERs provide to the general class of ratepayers. In keeping with the above scope, the Study also does not evaluate the costs or benefits specific to participant ratepayers.[27] Thus, the results of the Study do not provide all of the information necessary to conduct a cost-benefit analysis. Rather, the results of the Study will be critical in informing future cost-benefit analyses in the context of resource selection and compensation.

STUDY STRUCTURE

The Study is broken into four Sections: I. Introduction; II. Connecticut-Specific DER Value Quantification; III. Discussion of Additional DER Value Categories; and IV. Conclusion.

Section II. quantitatively evaluates six DER technology applications, or Use Cases, using the dispatch modeling approach outlined in Appendices A. and B. Section II. specifically quantifies the value of the following categories provided by DERs to Connecticut: (1) wholesale electric system costs and benefits, including transmission impacts; (2) emissions-related climate benefits; and (3) emissions-related local health benefits.

Section III. includes examples of quantification from other studies or jurisdictions, and provides additional analysis and qualitative discussion on the value of the following categories provided by DERs (continued from above): (4) macroeconomic costs and benefits; (5) distribution system costs and benefits; (6) resilience benefits; and (7) other health and environmental benefits. Section III. broadly evaluates these DER value categories irrespective of technology and jurisdiction, but does provide technology- and jurisdiction-specific

---

[24] See Appendix B. for additional details.

[25] Conversely, the Study does not quantify value categories that exclusively benefit specific customers without the possibility of providing net benefits to the electric system or Connecticut as a whole.

[26] The inclusion of program costs in the Study created a "chicken or egg dilemma." If the Study is meant to inform future DER programs and policies, the details of which will determine program costs, how could any assumption regarding program costs be practically included? Further, if the aim of the Study is to help policymakers and regulators design policies and programs to maximize the benefits of DER deployment, would not the inclusion of any assumption around program costs or how much of the technology costs are borne by ratepayers aid in predetermining such program and policy designs? Additionally, while it is vitally important in any cost-benefit analysis to assign costs and benefits to those who pay or benefit, it is practically impossible to do so precisely without knowledge of the program design.

[27] For example, the value of energy bill savings to participants in energy efficiency programs or net metering are not included in the benefits attributable to energy efficiency in the Study, nor are the ratepayer costs associated with those programs, which vary greatly.

analysis where available. Ultimately, Section III. provides limited quantification of macroeconomic costs and benefits and adjustments to the quantification of avoided emissions benefits provided in Section II.

Section IV. provides important, additional context for the Study and outlines next steps for both Agencies.

SUMMARY RESULTS

The six Use Cases (UCs) evaluated in the Study are:

UC1: Behind-the-Meter (BTM) Solar Photovoltaic (PV)
UC2: Front-of-the-Meter (FTM) Solar PV
UC3: BTM Solar PV Paired with Electric Storage
UC4: FTM Electric Storage
UC5: Fuel Cell
UC6: Energy Efficiency

Quantification of the DER value categories for each Use Case was completed by comparing the dispatch model results of the Reference Case, defined in Appendix A., with the dispatch model results for each Use Case. Below are the summaries of the dispatch model results and other quantification provided in Section II. modified to accommodate the additional quantifications and adjustments provided in Section III.; namely, that a value of $10.6/MWh should be used to approximate the net macroeconomic benefit of increased DER deployment in each Use Case and that a 3x multiplier be applied to the dispatch model valuation of avoided CO_2 emissions to reflect more recent SCC calculations.

The results presented below must be understood in the context of the specific Use Cases defined in Appendix B. as a different set of assumptions or operating parameters for any one Use Case could lead to different results. For example, using different operating parameters for the FTM electric storage Use Case could have resulted in greater emission reductions. However, allowing the FTM electric storage Use Case to operate based on energy arbitrage likely resulted in the highest total value quantification (*i.e.* the sum of the net monetized benefits of all the DER value categories quantified using dispatch modeling) for that Use Case.[28] The Agencies attempted to apply realistic modeling assumptions and parameters, based on publicly available information, that would lead to the highest total value quantification for each Use Case.

Further, the energy efficiency Use Case is not meant to represent a specific, or even a typical efficiency measure. Instead, the energy efficiency Use Case reduces load across all hours in a given year equally to measure the benefits of reduced load in each hour of the year. Such an analysis can be used to further evaluate specific or a typical efficiency measure, but should not be understood as a representation of the value of energy efficiency measures and nor should it be used to compare the relative value of energy efficiency measures with other DERs. This approach was taken to aid in future cost-benefit analysis of energy efficiency measures and programs.

[28] The Agencies provide this as an illustrative example, acknowledging that it is impossible to verify the hypothesis presented without explicitly modeling the alternative FTM electric storage Use Case described.

Summary Charts

The Use Case results are presented below on both a levelized per MWh basis and on an annual unitized basis (*i.e.* per MWh). Levelized and average annual values were computed for each DER value category. The 25-year levelized values utilized a net present value (NPV) calculation that assumed a nominal discount rate of seven percent.[29]

Figure 1: 25-Year Levelized Value of DER Use Cases per MWh of DER (nominal $)

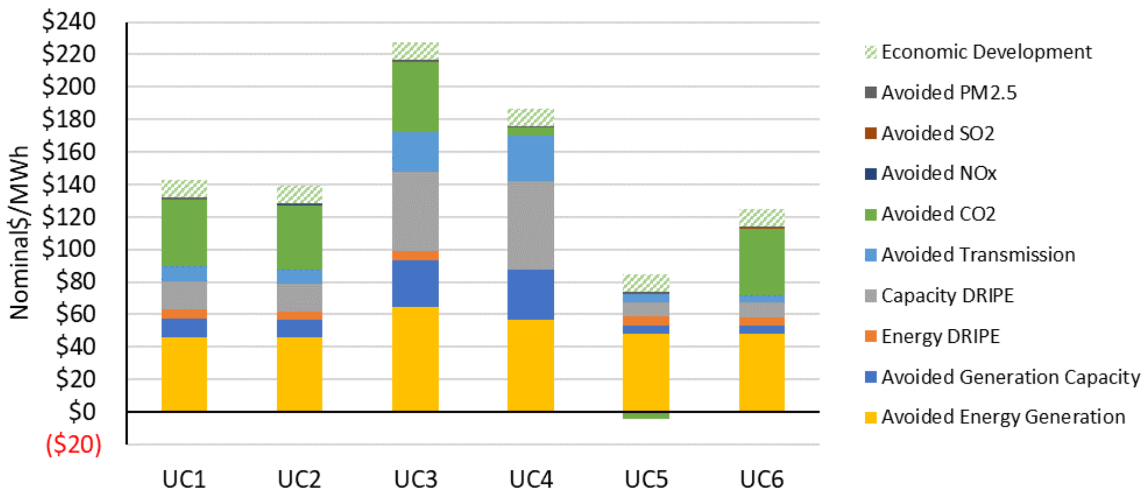
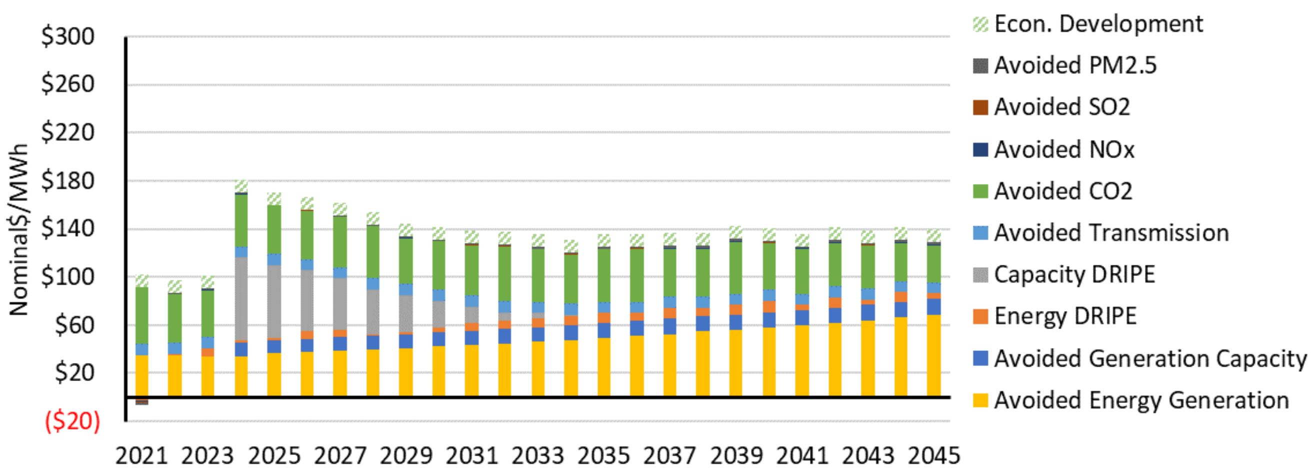


Figure 2: Average Annual Value of DER Use Cases per MWh of DER, UC1: BTM Solar PV (nominal $)



[29] A nominal discount rate of seven percent represents the approximate weighted average cost of capital of Connecticut's electric distribution companies, *See*, Decision, dated April 18, 2018, https://www.eversource.com/content/docs/default-source/investors/2018-ct-final-decision.pdf?sfvrsn=f23fc262_2. *See also*, Decision, dated December 14, 2016, http://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/0585d33b5c3fd0a48525829c006fe19e?OpenDocument.

Figure 3: Average Annual Value of DER Use Cases per MWh of DER, UC2: FTM Solar PV (nominal $)

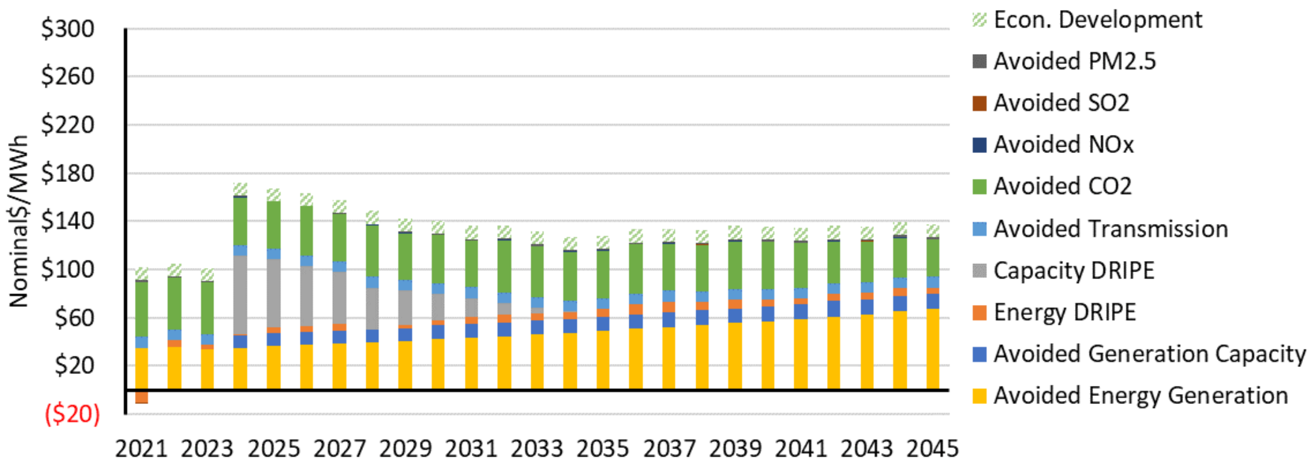


Figure 4: Average Annual Value of DER Use Cases per MWh of DER, UC3: BTM Solar PV Paired with Electric Storage (nominal $)

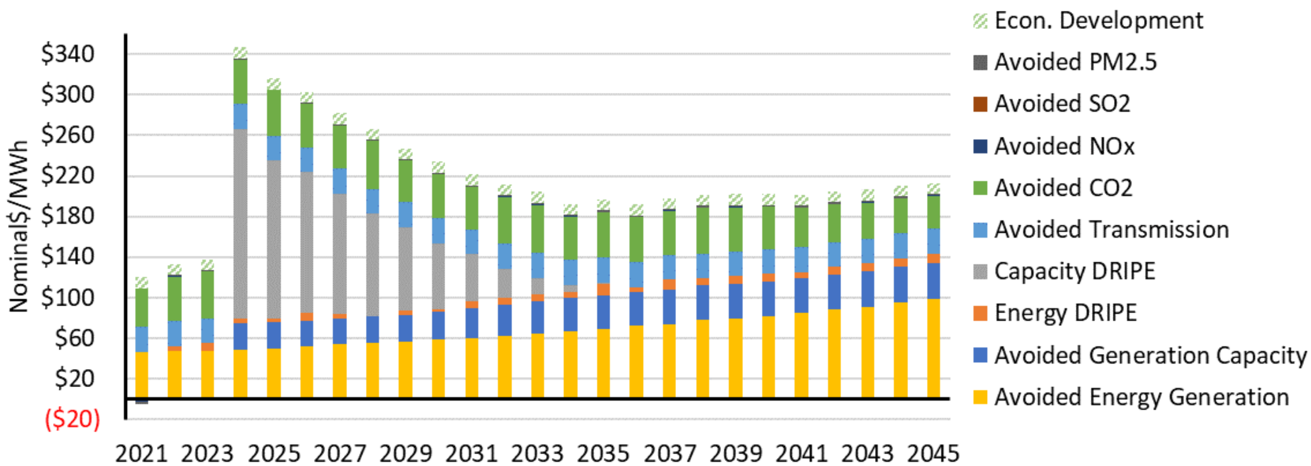


Figure 5: Average Annual Value of DER Use Cases per MWh of DER, UC4: FTM Electric Storage (nominal $)

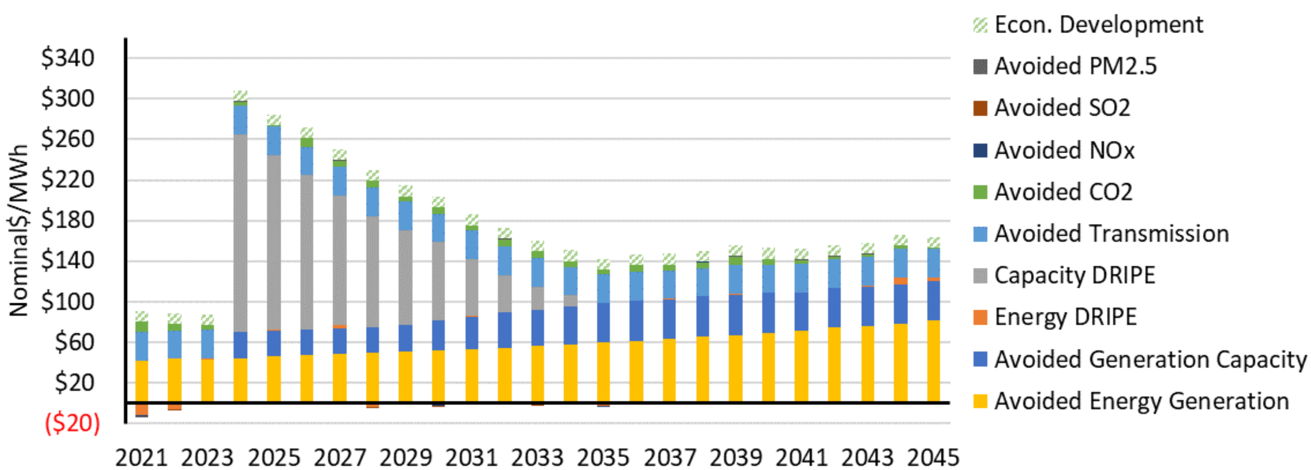


Figure 6: Average Annual Value of DER Use Cases per MWh of DER, UC5: Fuel Cell (nominal $)

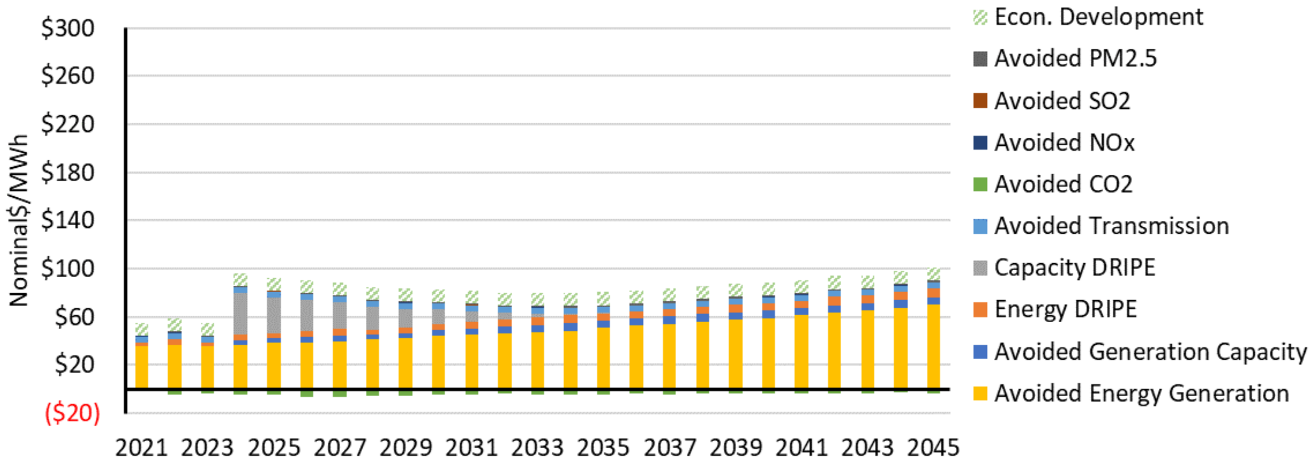
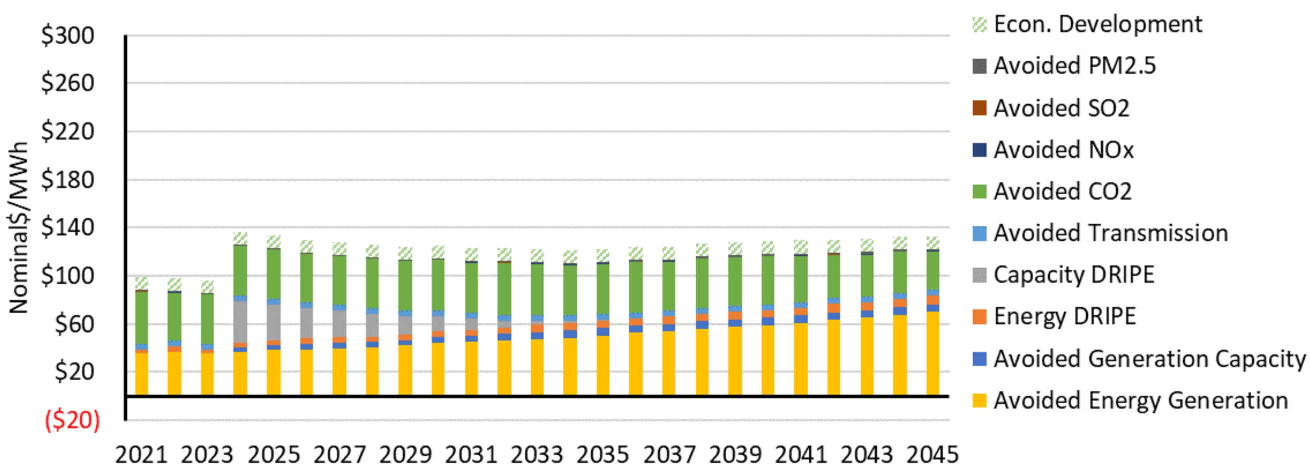


Figure 7: Average Annual Value of DER Use Cases per MWh of DER, UC6: Energy Efficiency (nominal $)



II. Connecticut-Specific DER Value Quantification

ELECTRIC SIMULATION MODELING

The Study utilized an electric system simulation model to quantify certain DER value categories that are oriented around the wholesale electricity market from 2021 through 2045. Specifically, the Study used Aurora, a chronological dispatch simulation model, to forecast power market outcomes to calculate the benefits provided by DERs to Connecticut for the following DER value categories: (1) wholesale electric system costs and benefits, including transmission impacts; (2) emissions-related climate benefits; and (3) emissions-related local health benefits. Table 2 details the DER value categories, and subcategories, that are specifically quantified and qualitatively discussed in this Section.

Table 2: DER Value Categories Included in Section II

Electric System Impacts			
Generation	**Avoided Energy Generation**	**Quantified**	Avoided MWh; avoided energy cost ($/kWh)
	Energy Demand Reduction Induced Price Effects (DRIPE)	**Quantified**	Avoided energy DRIPE cost ($/kWh)
	Avoided Generation Capacity	**Quantified**	Avoided MW; avoided capacity cost ($/kWh)
	Capacity DRIPE	**Quantified**	Avoided capacity DRIPE cost ($/kWh)
	Ancillary Services Avoided + Provided	**Qualitatively Discussed**	-
Transmission + Distribution	**Avoided T+D Line Losses**	**Quantified**	Cost impacts included in avoided energy costs; see Appendix B. for Use Case specific details
	Avoided Transmission Capacity	**Quantified**	Qualitatively discussed; quantification estimated
Societal Impacts			
Climate and Local Health Benefits	**Avoided Emissions (CO_2, NOx, SO_2, and $PM_{2.5}$)**	**Quantified**	Climate and local health benefit ($/kWh)

In order to quantify the value categories and subcategories in Table 2 a Reference Case and six DER technology Use Cases were established in collaboration with stakeholders and the Agencies' consultants.[30] The Reference Case represents a "business-as-usual" wholesale market forecast without the addition of new (*i.e.* incremental) DERs.[31] The DER technology Use Cases represent targeted DER deployment scenarios over the next ten years created to evaluate the most common and highest value DER technologies and technology combinations in Connecticut.[32] The six Use Cases (UCs) evaluated are:

UC1: Behind-the-Meter (BTM) Solar Photovoltaic (PV)
UC2: Front-of-the-Meter (FTM) Solar PV
UC3: BTM Solar PV Paired with Electric Storage
UC4: FTM Electric Storage
UC5: Fuel Cell
UC6: Energy Efficiency

The quantification of DER value categories for each Use Case was calculated by comparing the dispatch model results from the Reference Case with the dispatch model results for each Use Case. A summary of the dispatch model results (*i.e.* the Connecticut-specific DER value quantification) is presented in this Section.[33]

USE CASE RESULTS

The below Use Case results are presented as both total annual differentials relative to the Reference Case results provided in Appendix A. and on an annual unitized basis (*i.e.* per MWh). The annual total differentials do not account for differences in generation among the different types of DERs evaluated in each Use Case. Therefore, the quantified values for energy and emissions were unitized to allow for comparison across all DER Use Cases. Levelized and average annual values were computed for each DER value category. The 25-year levelized values utilized a Net Present Value (NPV) calculation that assumed a nominal discount rate

[30] *See*, Notice of Request for Written Comments, dated August 7, 2019, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/9b11e97ca52a77e58525844f006f7272?OpenDocument. *See also*, written comments filed in response to the August 7, 2019 Notice, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web%20Main%20View%5CAll%20Dockets)?OpenView&Start=476.1.57. *See also*, Notice of Technical Meeting, dated September 3, 3019, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/510c2b31d2d3369b8525846a004a465b?OpenDocument. *See also*, Notice of Request for Written Comments, dated January 30, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/45d27df5913bdef2852584ff004d973d?OpenDocument. *See also*, Notice of Technical Meeting, dated January 30, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/088afb04a5ccc037852584ff00585fea?OpenDocument. *See also*, Draft Technical Meeting Agenda, dated January 30, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/f67c57da83d6cb43852584ff00617a6d?OpenDocument. *See also*, written comments filed in response to the January 30, 2020 Notice, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web%20Main%20View%5CAll%20Dockets)?OpenView&Start=476.1.43.1.

[31] See Appendix A. for detailed assumptions and model inputs for the Reference Case.

[32] See Appendix B. for detailed assumptions and model inputs for the Use Cases.

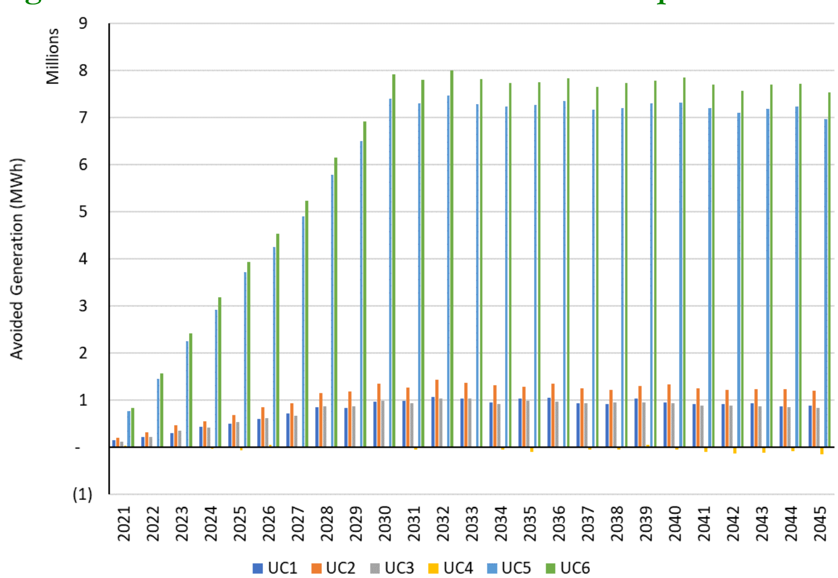
[33] See Appendix B.I. through Appendix B.VI. for detailed dispatch model outputs and results.

of seven percent.[34,35] The economic value of avoided CO_2 emissions was calculated as the Societal Cost of Carbon (SCC) based on a three percent discount rate, less the forecasted price of a Regional Greenhouse Gas Initiative (RGGI) allowance, or the Net SCC.[36] The RGGI allowance cost was deducted from the SCC because RGGI costs are already embedded in the energy price.

AVOIDED ELECTRIC GENERATION

Figure 8 shows the avoided electric generation for each Use Case, which reflects the net change in generation between the Reference Case and the Use Case and nets out the incremental DER generation from the Use Case.[37] The avoided generation across the Independent System Operator New England Inc. (ISO-NE) bulk power system ascribable to each Use Case shown in Figure 8 highlights the different capacity factors of the Use Case DERs and the magnitude of generation offset within Connecticut and throughout ISO-NE. Figure 9 shows the in-state benefits from avoided generation associated with each Use Case. As UC4 represents electric storage-only, it does not induce in-state or pool-wide avoided generation and contributes a total of approximately 862,000 MWh of increased generation in ISO-NE over the study period (2021-2045) due to storage losses.

Figure 8: Annual ISO-NE Avoided Generation per Use Case



---

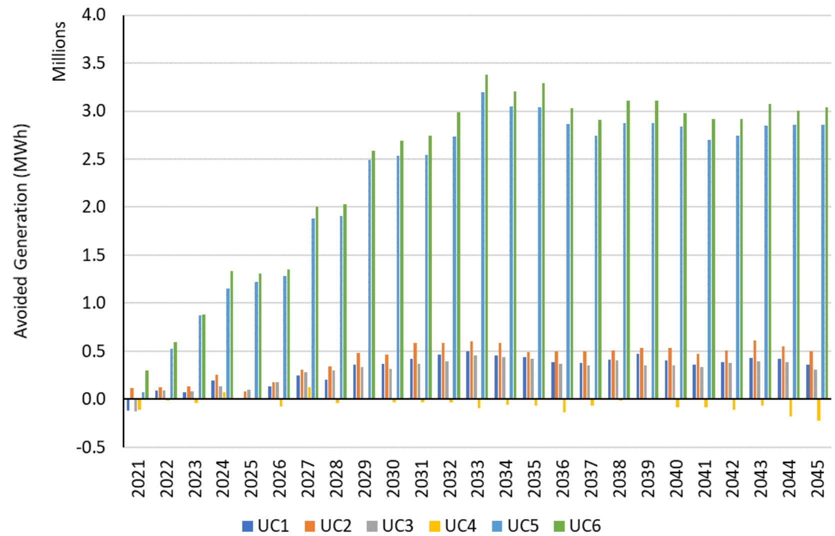
34 A nominal discount rate of seven percent represents the approximate weighted average cost of capital of Connecticut's electric distribution companies, *See*, Decision, dated April 18, 2018, https://www.eversource.com/content/docs/default-source/investors/2018-ct-final-decision.pdf?sfvrsn=f23fc262_2. *See also*, Decision, dated December 14, 2016, http://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/0585d33b5c3fd0a48525829c006fe19e?OpenDocument.

35 Some other calculations and value quantifications required the use of an inflation rate and base year, for which two percent and calendar year 2020 were used, respectively.

36 U.S. Government, Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, dated August 2016, https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf.

37 To a lesser degree, change in the Reference Case resource mix over the forecast period, described in Appendix A.. affects net imports to ISO-NE, and therefore, has a small impact on avoided generation within ISO-NE.

Figure 9: Annual Connecticut Avoided Generation per Use Case



ENERGY MARKET IMPACTS

Impact on Energy Prices

The addition of incremental DER generation in each Use Case impacts the load costs, commonly referred to as "cost-to-load", borne by Connecticut ratepayers relative to the Reference Case load costs. The value of reductions in wholesale energy prices as a result of adding DERs is commonly referred to as Energy Demand Reduction Induced Price Effects (DRIPE). The unitized value of energy DRIPE represents the forecasted annual Connecticut net cost-to-load divided by the annual DER generation for each Use Case.[38]

Further, the addition of incremental DER generation in each Use Case avoids electricity generation that would have otherwise been produced by another generation source, defined below as "Avoided Energy Generation." Avoided Energy Generation represents the annual energy revenues attained by the incremental DER resource for each Use Case. The unitized value of Avoided Energy Generation is the annual revenues divided by the annual incremental DER generation for each Use Case.

To compute a 25-year levelized value per MWh of DER for each Use Case, as shown in Figure 10 the total annual values of the Avoided Energy Generation and energy DRIPE were discounted at seven percent. Average annual values for each Use Case are illustrated in Figure 11 through Figure 16.. These figures show the sum of the Avoided Energy Generation and energy DRIPE in nominal values for each year. Annual values were unitized based on the DER energy delivered to the grid. For UC4, annual values were unitized based only on the discharge from storage into the grid.

---

[38] While in general the addition of DERs reduces cost-to-load, there are time periods when cost-to-load increases due, in part, to the need to commit and dispatch more flexible resources.

Figure 10: 25-Year Levelized Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (All Use Cases; nominal $)

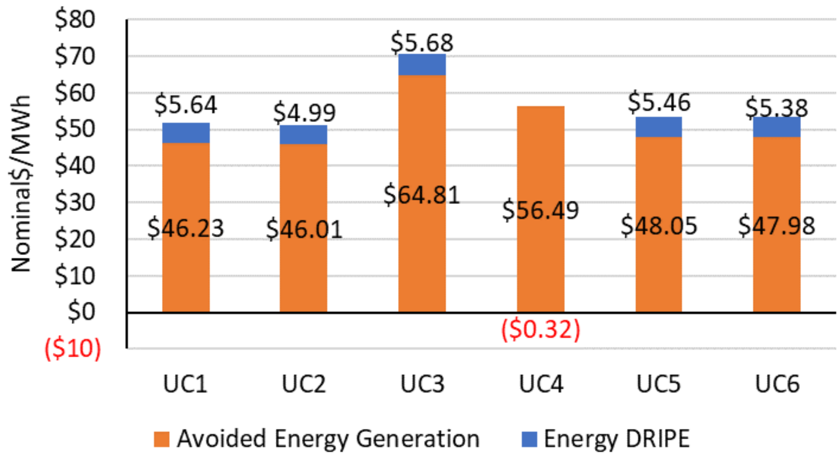


Figure 11: Average Annual Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (UC1; nominal $)

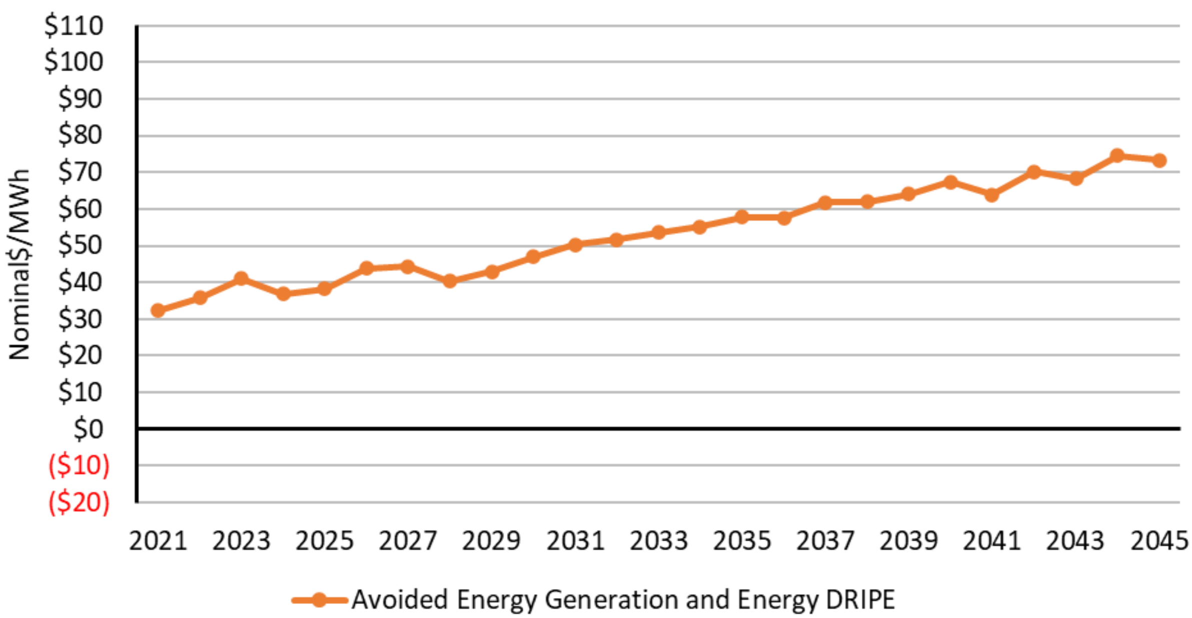


Figure 12: Average Annual Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (UC2; nominal $)

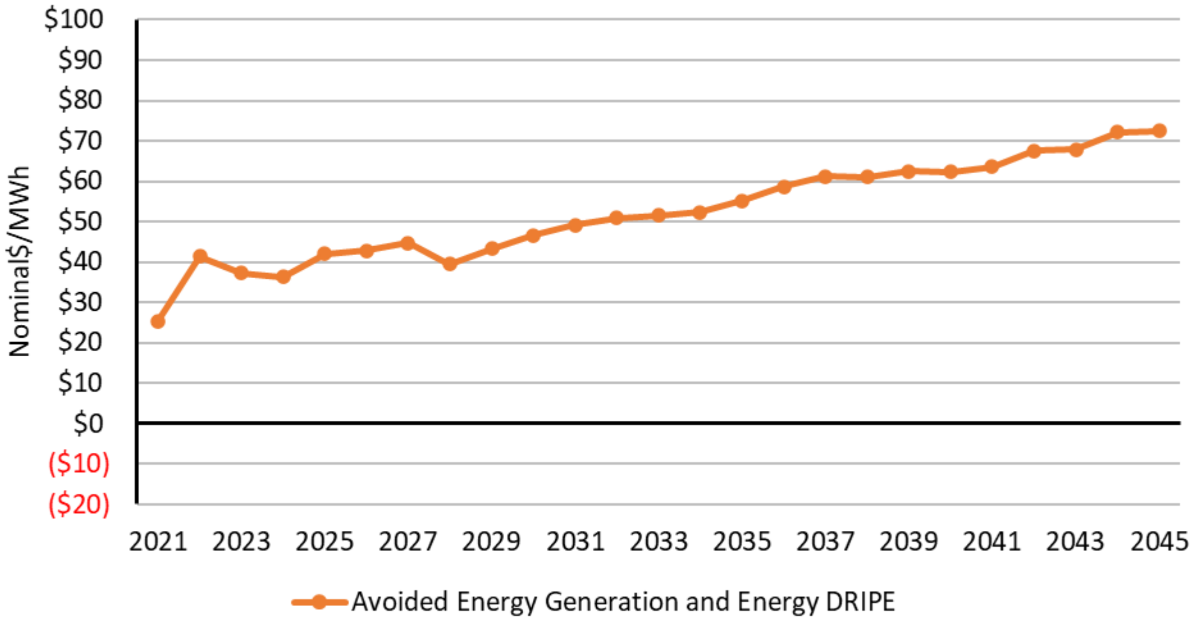


Figure 13: Average Annual Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (UC3; nominal $)

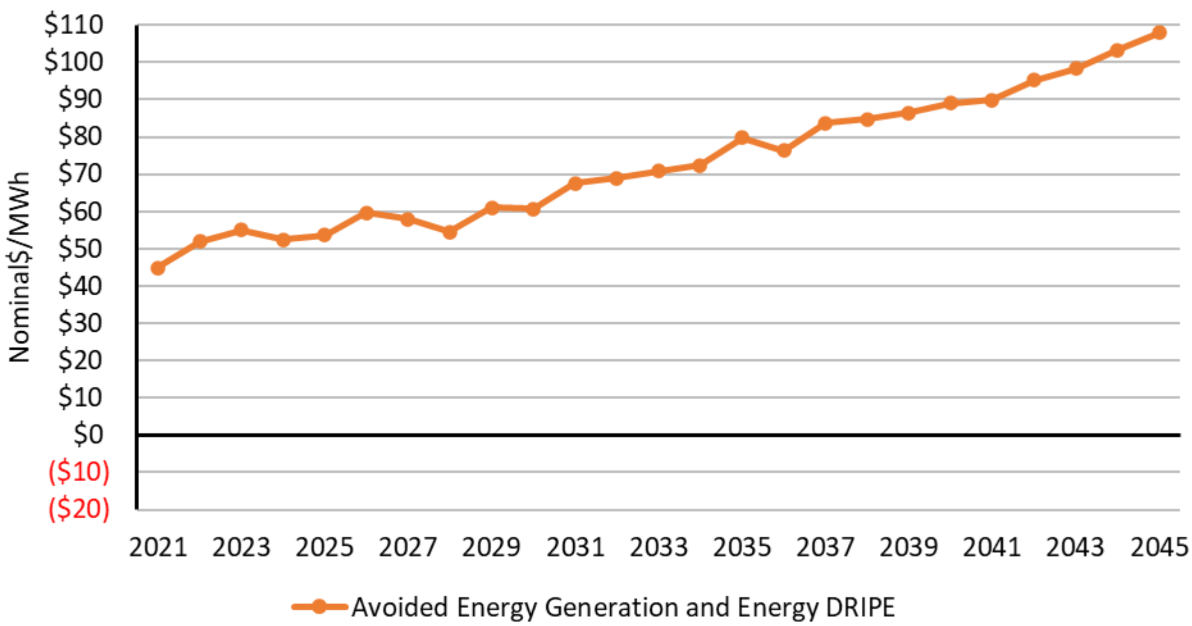


Figure 14: Average Annual Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (UC4; nominal $)

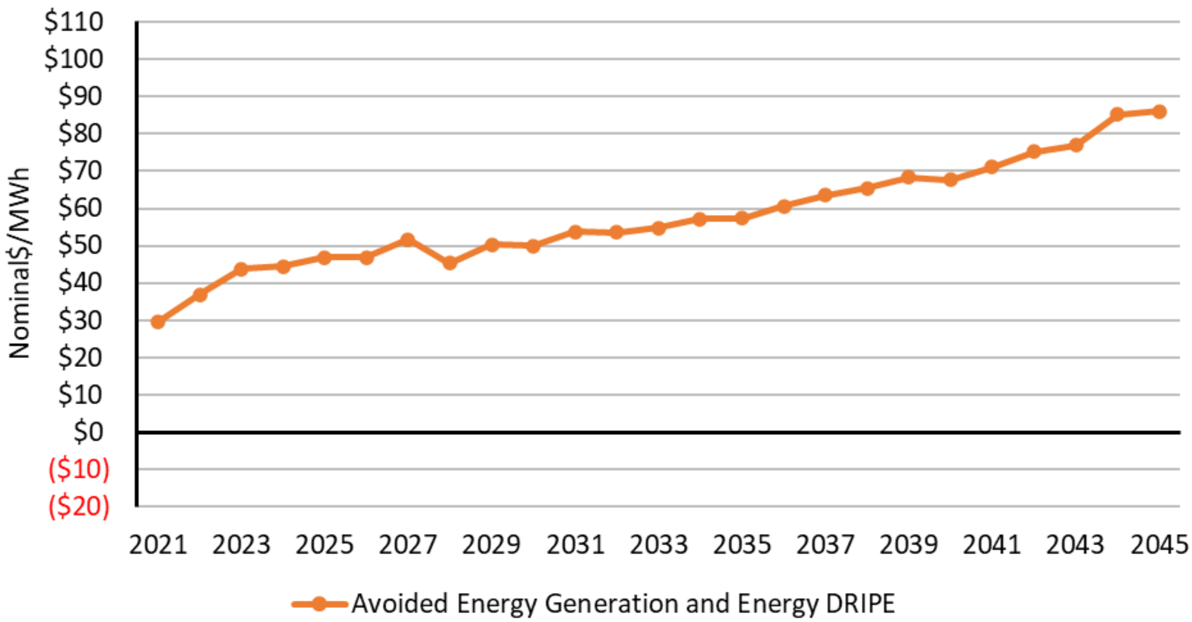


Figure 15: Average Annual Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (UC5; nominal $)

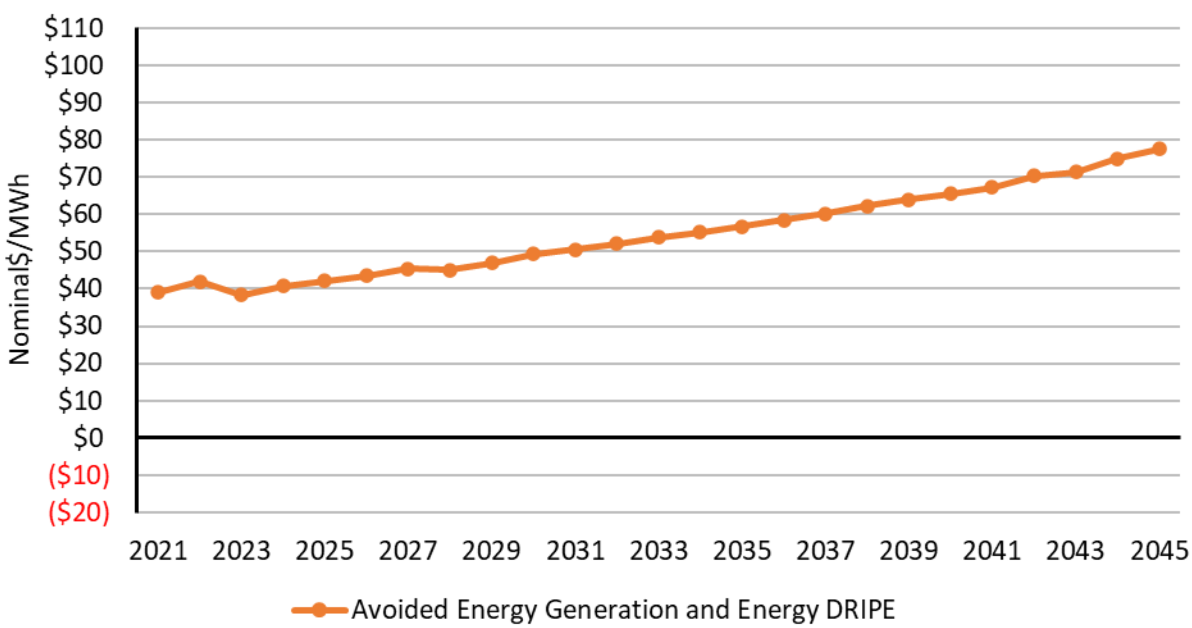
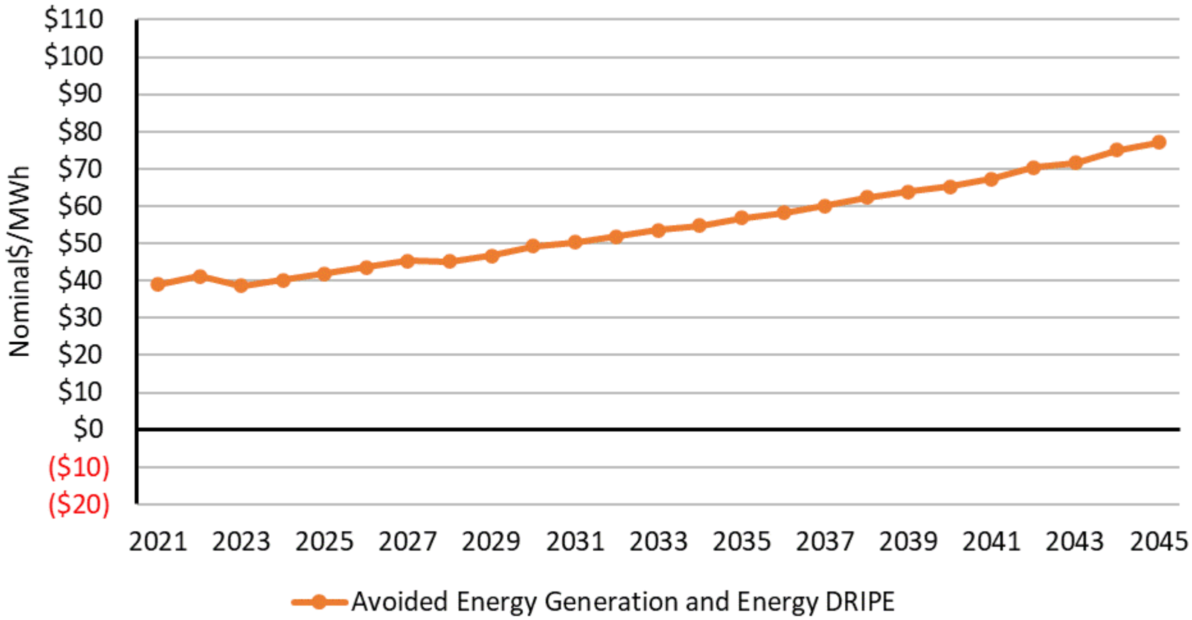


Figure 16: Average Annual Value of Avoided Energy Generation and Energy DRIPE per MWh of DER (UC6; nominal $)



CAPACITY MARKET IMPACTS

Supplemental analysis of the impact of the incremental DERs modeled in the Use Cases on the ISO-NE capacity market outcomes was performed independently of Aurora modeling. This supplemental analysis of the capacity impacts of each Use Case assumed the perpetuation of current Forward Capacity Market (FCM) rules surrounding capacity clearing and the Forward Capacity Auction (FCA) 14 demand curve geometry. The analysis also assumed that the incremental DER generation in each of the Use Cases either would have cleared the market at the level of expected summer peak MW contribution or otherwise would have been taken into account in setting the FCA demand curve in such a way that would have yielded the same or a substantially similar result.[39]

DER Resource Qualified Capacity

Each Use Case resource warrants a different level of summer peak contribution and therefore have varying effects on the amount of capacity avoided. As load modifying resources, some of the Use Case DERs may not qualify to participate in the FCM as a supply-side resource.[40] Table 3 summarizes the expected peak load contribution as a percentage of the resource nameplate that would be assigned to each Use Case DER.

[39] The Agencies note the difficulty that many new renewable resources have experienced in clearing the FCM as a supply-side resource.

[40] Denoted with an asterisk in
Table 3, FTM Solar PV, FTM Storage, Fuel Cells, and Energy Efficiency would likely participate in the FCM, as opposed to impacting the FCM demand as a load reducer.

Table 3: Use Case DER Resource Expected Peak Load Contribution

Use Case	DER Resource Type	Expected Peak Load Contribution (% of Nameplate Capacity)
1	BTM Solar PV	**See** Error! Reference source not found.
2	FTM Solar PV*	**34%**
3	BTM Solar PV + paired Storage	**See** Error! Reference source not found.
4	FTM Storage*	**100%**
5	Fuel Cell*	**93.75%**
6	Energy Efficiency*	**100%**

The expected peak load contribution of the resource represents the amount of avoided generation capacity associated with each DER. FTM Solar PV annual capacity additions in UC2 offset 34 MW of capacity for each 100 MW added annually.[41] FTM Storage annual capacity additions in UC4 contributed to peak at 100 percent of nameplate capacity per ISO-NE market rule and training materials.[42] Fuel Cell annual 100 MW capacity additions in UC5 reflected a 6.25 percent outage rate and contribute 93.75 MW to peak. Energy Efficiency resources provide around-the-clock demand reduction and therefore contributed the full annual increment of 100 MW to peak reduction, which has already been grossed up for transmission and distribution losses.

For UC1 and UC3, which include BTM PV, the expected peak load contribution was calculated annually to determine the effect of the summer peak hour shifting further into the evening in the future with increasing penetration of PV. Annual average generation during summer peak hours from UC1 and UC3 were used to derive the annual time series for each Use Case as shown in Table 4.[43]

---

[41] The description of Table 2.1: List of Generators' Existing and Expected Claimed Seasonal Capability included in the ISO-NE 2019 Capacity, Energy, Loads, and Transmission (CELT) Report indicates a summer capability of 34 percent is assigned to new PV resources, *See*, ISO-NE, 2019 CELT Report, dated April 30, 2019, https://www.iso-ne.com/static-assets/documents/2019/04/2019_celt_report.xls.

[42] *See*, ISO-NE, Section III, Market Rule 1, Standard Market Design, Section III.1.5.1.4., dated December 10, 2019, https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[43] A review of ISO-NE daily system peaks from the Aurora modeling determined the top 15 daily peak hours during the summer period for each year. Output for each Use Case was averaged across the 15 daily summer peak hours to determine the expected peak load contribution.

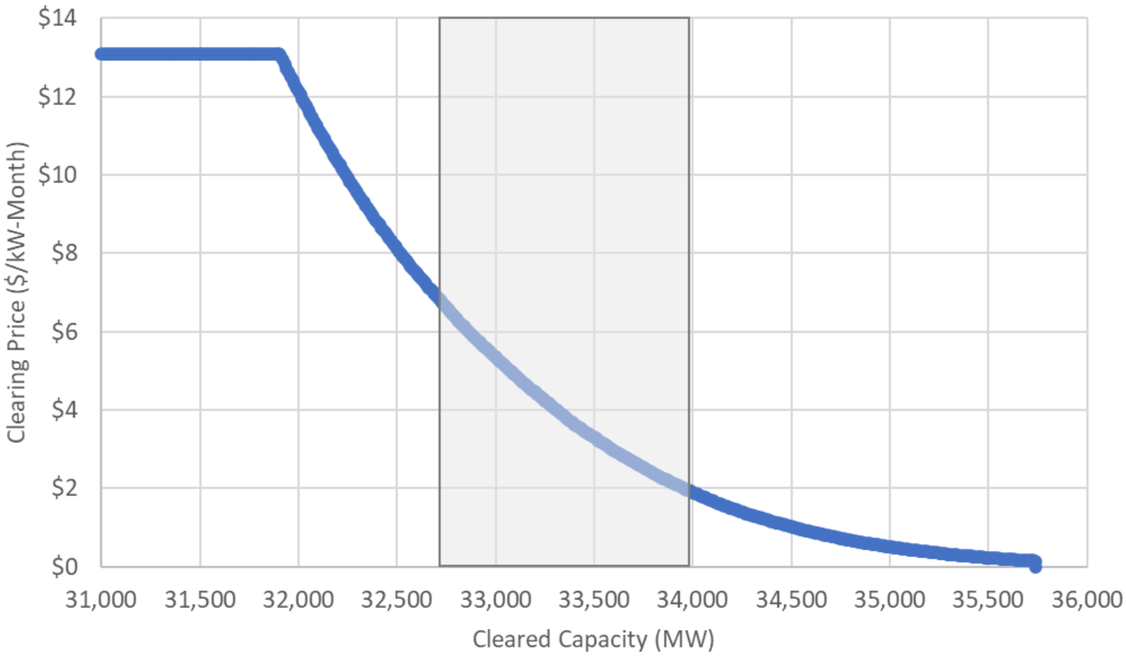
Table 4: Annual Expected Peak Load Contribution per 100 MW Nameplate Capacity of BTM Resource

Year	UC1	UC3
2021	**37.7**	**87.7**
2022	**35.3**	**79.8**
2023	**29.9**	**72.8**
2024	**25.3**	**67.7**
2025	**26.9**	**63.7**
2026	**26.8**	**68.6**
2027	**27.4**	**70.5**
2028	**25.5**	**69.4**
2029	**24.5**	**62.7**
2030	**20.6**	**62.8**
2031	**23.0**	**59.6**
2032	**26.1**	**63.6**
2033	**25.5**	**65.3**
2034	**23.3**	**65.7**
2035	**20.6**	**57.3**
2036	**21.5**	**59.0**
2037	**23.1**	**61.8**
2038	**24.2**	**64.4**
2039	**22.2**	**62.7**
2040	**20.9**	**60.7**
2041	**18.9**	**63.0**
2042	**20.9**	**64.0**
2043	**21.6**	**67.1**
2044	**21.7**	**63.4**
2045	**19.9**	**65.1**

Impact on Capacity Prices

A reduction in the FCA capacity clearing price may be ascribable to the avoided generation capacity from each Use Case. This analysis of capacity market DRIPE assumed the perpetuation of the current FCM structure and relied on the geometry of the most recent (FCA 14) demand curve as a foundation. The concave sloped demand curve used to conduct the FCA, as shown in Figure 17 is comprised of 10 MW increment price and quantity pairings ranging from $13.10/kW-Month to $0/kW-Month.

Figure 17: FCA 14 Demand Curve



The analysis used the FCA 14 curve to trace the capacity price impact of adding the annual increments of DERs from each Use Case shown in Figure 18 using each of the most recent FCA clearing prices shown in Table 5. Due to the concavity of the demand curve, the change in capacity price for a given quantity change in MW of capacity will not yield the same impact for each starting price. Therefore, the analysis made use of the average change in capacity price across the range of recent FCA outcomes shown in grey in Figure 17.

Table 5: Recent FCA Clearing Price & Quantity Pairings[44]

FCA #	Price ($/kW-Month)	Capacity (MW)
FCA 10	**$7.03**	**32,670**
FCA 11	**$5.30**	**33,010**
FCA 12	**$4.63**	**33,150**
FCA 13	**$3.80**	**33,350**
FCA 14	**$2.00**	**33,950**

Whereas the cumulative avoided generation capacity in Table 6 does not reflect any reduction in impact over time, it is reasonable to assume that any reduction in price will result in offsetting reductions in capacity supply as other resources in the market respond. This is referred to as the decay factor. The decay factor could be caused by various factors, since "lower capacity prices may result in the retirement of some generation resources and termination of some demand-response resources" or "new proposed resources…

[44] Note that cleared capacity used in this analysis does not reflect the actual cleared capacity resulting from that particular FCA, but rather the capacity price on the FCA 14 demand curve that would match that auction's clearing price.

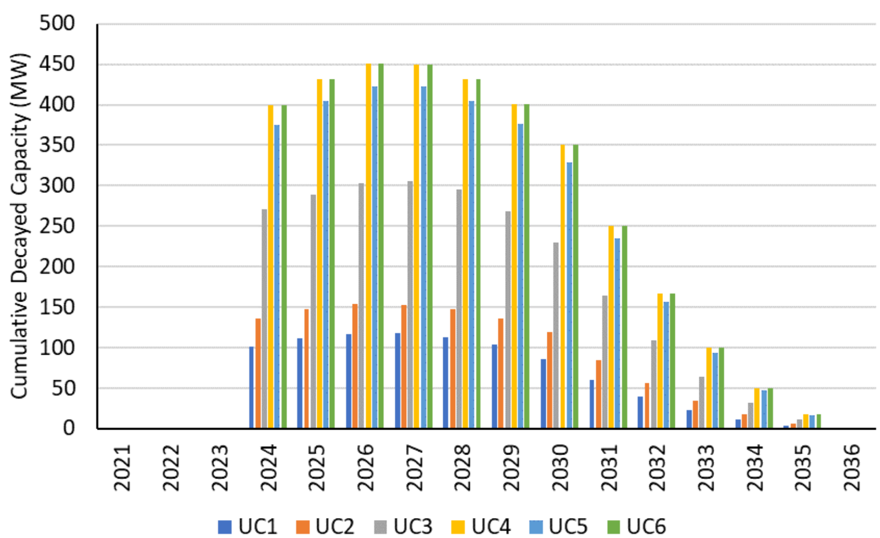
may be withdrawn."[45] Table 6 provides the schedule for decay of the capacity market impact over time.[46] The decay factor was applied to each annual incremental addition of capacity for each Use Case such that the cumulative capacity market price reduction effect is phased out by 2036 (i.e. six years after the final incremental addition of the DER in 2030) as shown in Figure 18.

Table 6: Decay Factors in Capacity DRIPE Calculation[47]

Year	Decay Factor
1	**1.00**
2	**0.83**
3	**0.67**
4	**0.50**
5	**0.33**
6	**0.17**
7	**0.00**

Incremental capacity was not assumed to offset any generation capacity until 2024 as the three-year forward capacity market has already determined the generating capacity required to maintain reliability through 2023. Incremental capacity added prior to 2024 was summed and added to the capacity market in 2024. The year 1 decay factor was applied in 2024 to all cumulative capacity added up to 2024.

Figure 18: Annual Cumulative Capacity[48]



[45] Synapse Energy Economics, Inc., Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage, Avoided Energy Supply Components in New England: 2018 Report, dated October 24, 2018, Section 9.2, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.

[46] *Id.*, Table 67.

[47] The Agencies note that while the capacity commitment period runs from June through May of the following year, this analysis looked at the capacity market impacts on a calendar year basis.

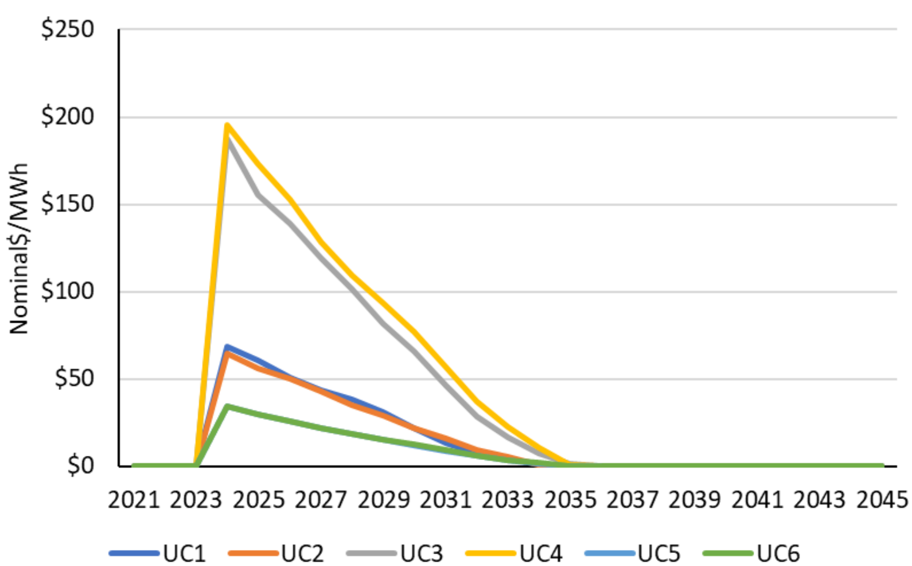
[48] Cumulative capacity shown in the figure reflects the reduction in capacity market price impact per the decay schedule in **Error! Reference source not found.**.

The change in the capacity market clearing price ascribable to adding the cumulative capacity of each Use Case DER was calculated for each year from 2024 through 2045 using the FCA 14 demand curve as the foundation. Starting with each of the FCA clearing prices and quantities in Table 5 as a reference price, the annual cumulative DER capacity was added to the curve to derive the reduced clearing price that would result in each year ascribable to the DER capacity. Annual capacity DRIPE was computed as the difference between Connecticut's annual capacity obligation at the FCA reference price and the FCA clearing price, and the quantity resulting from the additional DER capacity.

To derive the change in Connecticut's annual capacity obligation ascribable to the additional DER capacity, the FCA clearing price resulting from the additional DER capacity was first calculated for each of the recent FCA outcomes (FCA 10 through 14), and the average value was used to represent the reduced capacity clearing price. The annual ISO-NE capacity obligation without the incremental DERs was computed as the product of the total ISO-NE capacity obligation (in MW) and the capacity clearing price at the reference price. The annual ISO-NE capacity obligation for each Use Case was computed as the product of the ISO-NE capacity obligation including the DER capacity and the reduced price. Connecticut's 24.3 percent share of the total annual capacity payment was based on the Connecticut's share of the total ISO-NE coincident summer peak from the 2019 CELT report. The annual capacity DRIPE benefit to Connecticut load from each Use Case represents its 24.3 percent share of the change in annual total capacity payment from the incremental DERs.

To unitize the Use Case capacity DRIPE benefit, Connecticut's share of the annual capacity payment reduction was divided by the MWh of incremental DER generation for each Use Case in that year. Figure 19 provides the annual capacity DRIPE benefit per MWh of Use Case DER.

Figure 19: Annual Connecticut Generation Capacity DRIPE Benefit per MWh of DER (nominal $)



Avoided Generation Capacity

In addition to the capacity DRIPE impact, Connecticut ratepayers will benefit from avoided generation capacity payments associated with the incremental DERs in each Use Case. The cumulative avoided generation capacity for each Use Case from 2030 (i.e. when the full 1,000 MW of the DER is built out) is shown in Table 7. BTM PV avoids less generation capacity than FTM PV as it has a lower annual capacity factor; whereas BTM PV plus paired storage avoids more than double the standalone BTM PV due to the paired storage system dispatching during high-priced peak hours.

Table 7: Total Study Period Cumulative Avoided Generation Capacity

Use Case	Avoided Capacity (MW)
UC1: BTM PV	**253**
UC2: FTM PV	**340**
UC3: BTM PV + Storage	**668**
UC4: FTM Storage	**1,000**
UC5: Fuel Cell	**938**
UC6: Energy Efficiency	**1,000**

While the cumulative capacity from each Use Case DER that contributes to capacity market DRIPE is decayed over a seven-year schedule, this analysis assumes that Connecticut ratepayers benefit from peak reductions from the full cumulative capacity of the incremental DERs for each Use Case without decay. However, annual avoided generation capacity payments will decrease as a result of the peak reduction in each Use Case. Avoided generation capacity payments were calculated by multiplying the full cumulative capacity of the incremental DERs for each Use Case by the annual clearing price. To unitize the Use Case avoided generation capacity payment benefit, the value of annual avoided capacity payment was divided by the MWh of incremental DER generation for each Use Case in that year.

Figure 20: Annual Connecticut Avoided Generation Capacity Payment per MWh of DER (nominal $)

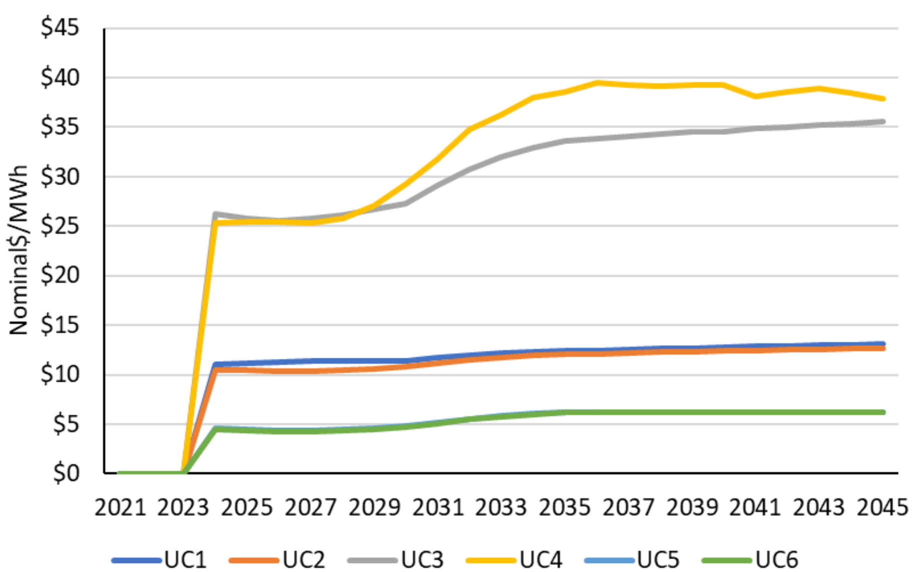
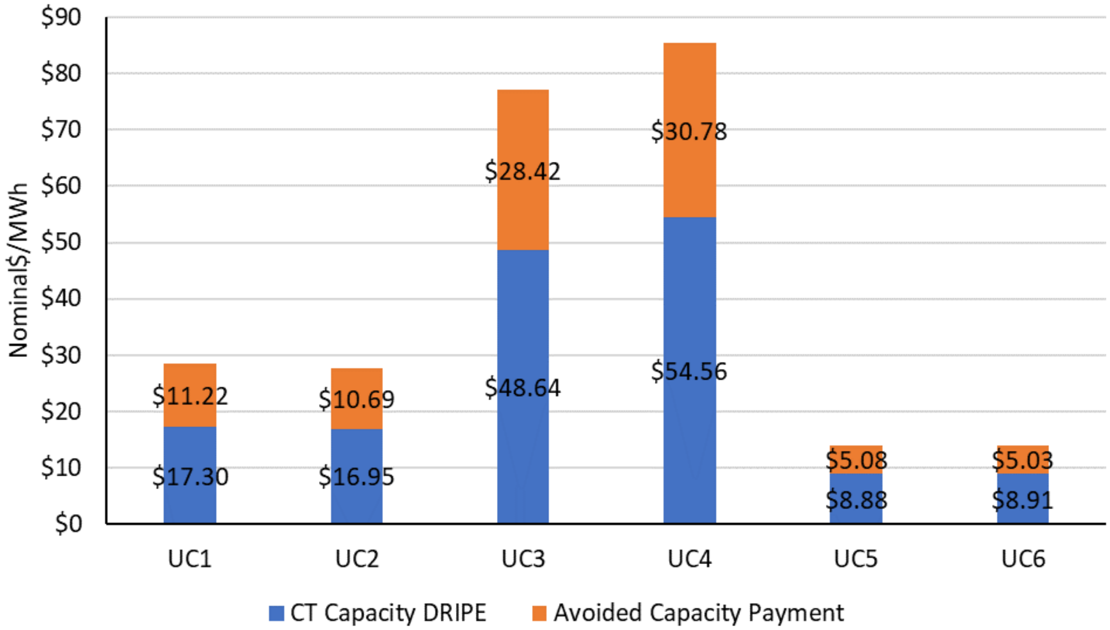


Figure 21 displays the nominal levelized capacity DRIPE and avoided capacity benefit for each Use Case.

Figure 21: 25-Year Levelized Value of Generation Capacity DRIPE and Avoided Generation Capacity Benefit per MWh of DER (nominal $)



AVOIDED TRANSMISSION CAPACITY

Review of interface flows in the Reference and Use Cases showed that interfaces in Northern New England were somewhat constrained over the forecasted period. Interfaces in Southern New England were minimally constrained. All Use Case scenarios would relieve zonal transmission constraints from Northern New England to Southern New England to some extent; however, given that the Reference Case forecast showed limited constraints, there is limited value for avoided transmission capacity. What value exists is captured, in part, through reduced transmission congestion, which impacts energy prices. The Aurora analysis did not consider any value of avoided distribution-level transmission capacity.

Further, the Aurora model is a zonal model and therefore would not identify any intra-zonal transmission issues that are either caused or alleviated by the addition of DERs. The model will re-dispatch around inter-zonal transfer limits, but will not re-dispatch around a transmission limit within a zone. For example, the model would not pick up transmission problems caused within southeastern Massachusetts caused by the interconnection of large amounts of offshore wind until the interconnection exceeds the transfer limits between zones. The zonal model would also not pick up the transmission level problems that areas such as Western Massachusetts are seeing from higher penetrations of distributed solar. On the transmission issues caused by DERs, ISO-NE has noted that, "due to large accumulations of DG on certain parts of the distribution system, smaller projects in the > 1 MW and < 5 MW range (for which a Generator Notification Form previously sufficed) are triggering the need for transmission studies because the interconnections will have a cumulative impact on the regional power system. Given the recent, dramatic growth in DG across New England, the ISO expects a growing number of projects in the > 1 MW and < 5 MW range to require additional study by the Transmission Owner to ensure no significant adverse impact on the regional power system in accordance with Section I.3.9 of the ISO Tariff."[49]

Ultimately, the Aurora model did not identify a significant reduction in inter-zonal transmission constraints for any of the Use Cases beyond what was already captured through energy prices. The Aurora model, however, is unable to determine any intra-zonal transmission impacts, which include reduced transmission constraints as well as increased transmission constraints as the examples above illustrate.

While the modeling performed through the Aurora dispatch modeling was unable to quantify avoided transmission benefits provided by DERs outside of energy prices, the Agencies recognize that DERs likely provide some value through deferred transmission capacity upgrades and other avoided marginal transmission costs. As such, the Agencies provide an approximate quantification of the value of avoided transmission costs delivered by the DERs below based on the literature review conducted for the Study.

The literature review conducted for the Study found three studies, one in Maryland, Mississippi, and Arkansas,[50] which provided methodologies for specifically evaluating the value DERs provide in avoiding transmission capacity costs. The Agencies utilized a simplified version of the methodology used in Mississippi and Arkansas to estimate the avoided transmission cost value for each Use Case calculated in Figure 15.

Specifically, the Agencies looked at the approximate value that the 2021 DER modeled deployment for each Use Case could provide in avoided transmission system costs in 2021. The Agencies applied a two percent inflation rate to the total annual marginal transmission avoided cost ($/kW-year) calculated in the Arkansas study for 2017[51] to derive a marginal transmission avoided cost for 2021.[52] The Agencies then used the total Study period cumulative avoided generation capacity provided in Table 7 of the Study divided by 10 (years) to calculate the 2021 avoided generation capacity for each Use Case, as well as the total 2021 generation for

---

49 ISO-NE, The Growth of Distributed Generation: ISO New England's Role in the Interconnection Review Process, dated October 2019, p. 4, https://www.iso-ne.com/static-assets/documents/2019/10/iso_new_england_interconnection_review_process_information_resource_october_2019_final.pdf

50 *See*, Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf. *See also*, Synapse Energy Economics, Inc., Net Metering in Mississippi: Costs, Benefits, and Policy Considerations, dated September 19, 2014, https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf. *See also*, Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

51 *See*, Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, pp. 16-17, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view

52 The study conducted in Mississippi used $33/kW-year in 2013 to calculate avoided transmission costs, *See*, Synapse Energy Economics, Inc., Net Metering in Mississippi: Costs, Benefits, and Policy Considerations, dated September 19, 2014, p. 28, https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

each Use Case provided in Appendices B.I. through B.VI., to calculate the avoided transmission values provided in Table 8.[53]

Table 8: Estimated Avoided Transmission Costs Value by Use Case (2021)

	Avoided Capacity (MW)	Differed Transmission Costs ($)	Annual Generation, Modeled 2021 DER Deployment (MWh)	Annual Unitized Transmission Capacity Benefit
UC1	25.3	$1,062,559	116,369	$0.0091/kWh
UC2	34.0	$1,427,945	161,148	$0.0089/kWh
UC3	66.8	$2,805,491	113,900	$0.0246/kWh
UC4	100.0	$4,199,837	149,242	$0.0281/kWh
UC5	93.8	$3,939,447	821,264	$0.0048/kWh
UC6	100.0	$4,199,837	876,000	$0.0048/kWh

The above results are in-line with the findings of a 2013 Rocky Mountain Institute study[54] and are slightly above the calculated values provided in the value of solar study in Maryland, which estimated the value of avoided transmission costs attributable to solar PV between 0.06¢/kWh and 0.50¢/kWh. The Agencies note that while this analysis is not specific to Connecticut, it yields comparable results to other noted studies. Thus, the Agencies apply the above results in the Summary Results in Section I.[55]

ANCILLARY SERVICES AVOIDED AND PROVIDED

Ancillary services are defined in the Federal Energy Regulatory Commission (FERC) Glossary as "[t]hose services necessary to support the transmission of electric power from seller to purchaser, given the obligations of control areas and transmitting utilities within those control areas, to maintain reliable operations of the interconnected transmission system. Ancillary services supplied with generation include load following, reactive power-voltage regulation, system protective services, loss compensation service, system control, load dispatch services, and energy imbalance services."[56] Ancillary services are often discussed as distribution voltage and power quality, particularly as it relates to the deployment of DERs. As discussed in Section III., DERs can both increase and decrease costs associated with distribution voltage and power quality. Similarly, DERs can also increase or decrease other ancillary services costs.

---

[53] For UC4, the gross dispatched or discharged energy values from the modeled FTM electric storage systems were used.

[54] Rocky Mountain Institute, A Review of Solar PV Benefits and Cost Studies: 2nd Edition, dated September 2013, p.31, https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf.

[55] The Agencies apply the results calculated for 2021 for each year of the study period, as the analysis provided herein is a useful approximation and not a precise estimation.

[56] *See*, Federal Energy Regulatory Commission (FERC), Glossary, https://www.ferc.gov/industries-data/market-assessments/overview/glossary.

Some studies of the value of DERs assume an increase in ancillary services as a component of integration costs, using the assumption that, generally, DERs are non-dispatchable, intermittent resources. Non-dispatchable DERs can cause additional operational costs (*e.g.* increases in regulation reserve requirements and load following reserve requirements) to account for sudden changes in output. The potential for intermittent resources, including DERs, to increase the costs of ancillary services has begun to impact wholesale market design considerations. ISO-NE recently filed significant market tariff revisions known as "Energy Security Improvements" (ESI), justified by the ISO, in part, on the expectation that the increased penetration of intermittent resources needs to be addressed, specifically stating: "The Energy Security Improvements' ancillary services will help the system manage the uncertainty over these resources' next-day energy production throughout the year. Further, the improvements will recognize and compensate resources for reliable, flexible, and responsive attributes that help the ISO manage, and prepare for, energy supply uncertainties each day."[57,58]

Although non-dispatchable DERs can add ancillary costs, DERs can also lower ancillary service costs. "For example, to the extent that…storage and distributed generation with sensors, controls, and communications systems can be better coordinated to reduce load, ancillary service costs for voltage and VAR support could be reduced, decreasing the cost for market participants and utilities."[59] The ability for DERs to avoid ancillary services costs is highly dependent on the specific project characteristics. What is clear is that, "[t]he ability to monitor and control . . . DERs is an important factor that affects the ability of these variable resources to provide ancillary services at the time of need."

Further, not only can DERs lower ancillary service costs, but dispatchable DERs can often provide a variety of ancillary services. Specifically, grid-scale energy storage can provide regulation and frequency response, as well as spinning and non-spinning reserves, renewable firming, and distribution voltage support, among other services.[60] Other dispatchable DERs, such as fuel cells, can also provide similar benefits.

However, given the uncertain nature of the impact of non-dispatchable DERs on the costs of ancillary services, the project-specific nature of the value of ancillary services provided by dispatchable DERs, and the relatively new implementation of FERC Order No. 841 in ISO-NE, the Agencies did not assign a

---

[57] *See*, ISO-NE, FERC Compliance Filing of Energy Security Improvements Addressing New England's Energy Security Problems, Docket Nos. EL18-182-000 and ER20-1567-000

[58] Ancillary services represent about $130 million of the total $12 billion ISO-NE wholesale market costs annually, *See*, ISO-NE, 2018 Annual Markets Report, dated May 23, 2019, https://www.iso-ne.com/static-assets/documents/2019/05/2018-annual-markets-report.pdf.

[59] State of New York Public Service Commission, Order Establishing the Benefit Cost Analysis Framework, CASE 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, dated January 21, 2016, Appendix C, p.7, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bF8C835E1-EDB5-47FF-BD78-73EB5B3B177A%7d.

[60] U.S. Department of Energy, Grid Energy Storage, dated December 2013, p. 25, https://www.energy.gov/sites/prod/files/2013/12/f5/Grid%20Energy%20Storage%20December%202013.pdf.

quantitative value to ancillary services in the Study.[61] Nonetheless, this result, in the context of the Study, should not be taken as a lack of awareness or perceived value of the benefits controllable and dispatchable DERs can provide in the form of ancillary services. Ultimately, the integration of DERs into the wholesale markets will be essential to maximizing their value going forward.

EMISSIONS IMPACTS

Avoided Emissions

The Aurora dispatch model analysis forecasted emissions for four pollutants: CO_2, NO_X, SO_2, and $PM_{2.5}$. Avoided emissions values, calculated as the change in emissions between the Reference Case and each Use Case, are provided in Appendix B.I. through Appendix B.VI for each Use Case.[62]

Value of Avoided Emissions

The annual value of avoided CO_2 per MWh of DER at the ISO-NE level represents the difference between the CO_2 emissions in the Reference Case and each Use Case.[63] Annual avoided CO_2 emissions were valued at the annual Net SCC (*i.e.* the SCC using a three percent discount rate less the forecasted RGGI allowance price). The unitized annual value of avoided CO_2 represents the product of the annual avoided CO_2 emissions and the Net SCC divided by the corresponding year Use Case generation. The total annual values of avoided CO_2 emissions were discounted at seven percent to compute a 25-year levelized value of avoided CO_2 per MWh of DER for each Use Case, as shown in Figure 22.[64] Annual values for each Use Case are shown in Figure 23 through Figure 28.[65]

---

[61] The Agencies note that tariff revisions relevant to the implementation of FERC Order No. 841 became effective in ISO-NE on December 1, 2019. Integration of dispatchable DERs into the wholesale ancillary service markets is vital to maximizing the value these resources can provide, *See*, FERC, Order on Compliance Filing New England Inc., Docket Nos. ER19-470-000, ER19-470-001, ER19-470-002, dated November 22, 2019, https://www.iso-ne.com/static-assets/documents/2019/11/er19-470-000_11_22_19_order_on_order_841_compliance_filing.pdf.

[62] Negative avoided emissions represent increased emissions ascribable to that Use Case and DER resource.

[63] The value of avoided CO_2 emissions for each Use Case was calculated using avoided CO_2 emissions for all of ISO-NE, consistent with Connecticut's consumption-based greenhouse gas emissions accounting policy.

[64] The 2016 Interagency Working Group (IWG) report forecasts future damages due to climate change through 2050, and provides SCC values from 2010 to 2050 in $/metric tons in 2007$. The IWG report calculates these values at three societal discount rates: two and one-half percent, three percent, and five percent. The intermediate value based on a societal discount rate of three percent was used for the analysis presented in this Section. Each annual SCC value was converted from constant 2007$/ton to nominal values using the actual historic inflation rate to the present year, then extrapolate at two percent per year through the end of the study period, 2045. The nominal SCC values for each year, less the RGGI price (in $/ton), was then multiplied by the annual quantities of avoided tons of CO_2 emissions to determine the annual economic values, in dollars, of avoided CO_2 emissions. The annual nominal values were then discounted by seven percent to calculate the 25-year levelized values.

[65] The increase in emissions of CO_2 in 2029 reflect the assumed retirement of Millstone.

Figure 22: 25-Year Levelized Value of Avoided CO_2 per MWh of DER (nominal $)

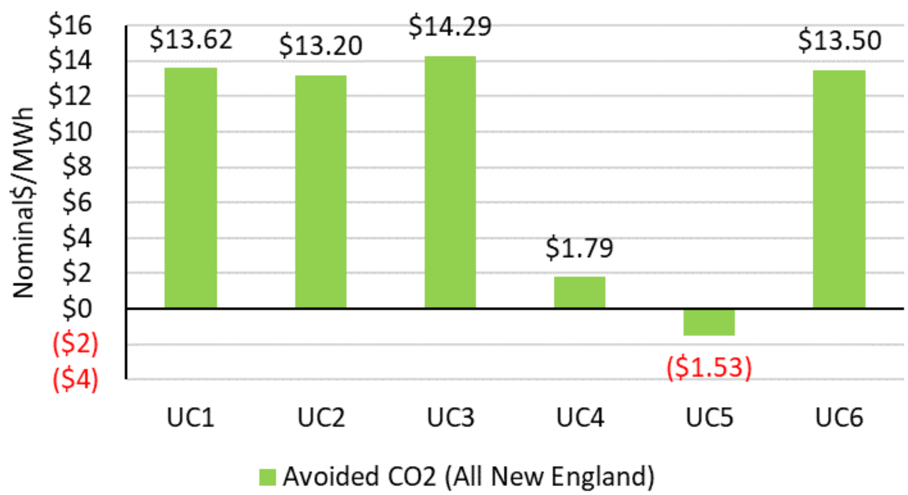


Figure 23: Average Annual Value of Avoided CO_2 per MWh of DER (UC1; nominal $)

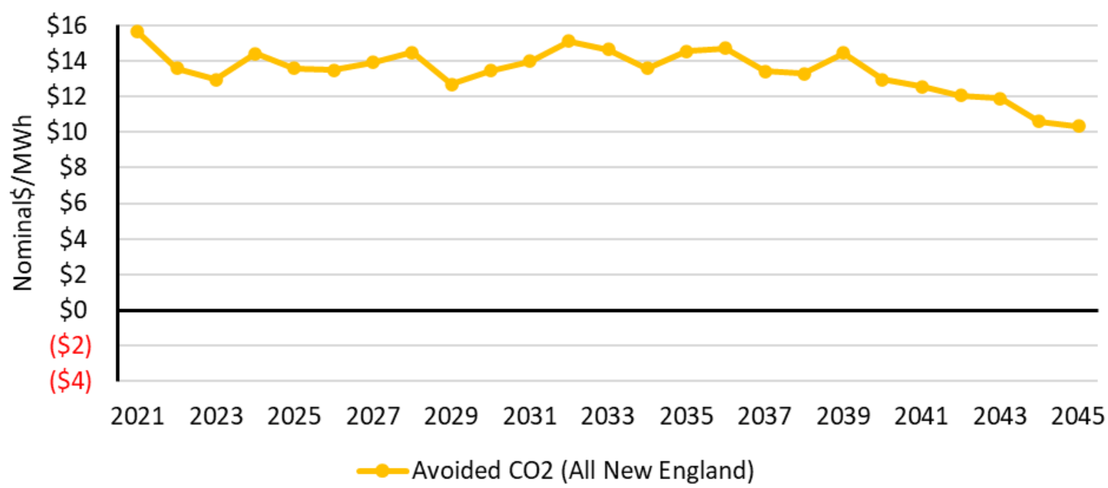


Figure 24: Average Annual Value of Avoided CO_2 per MWh of DER (UC2; nominal $)

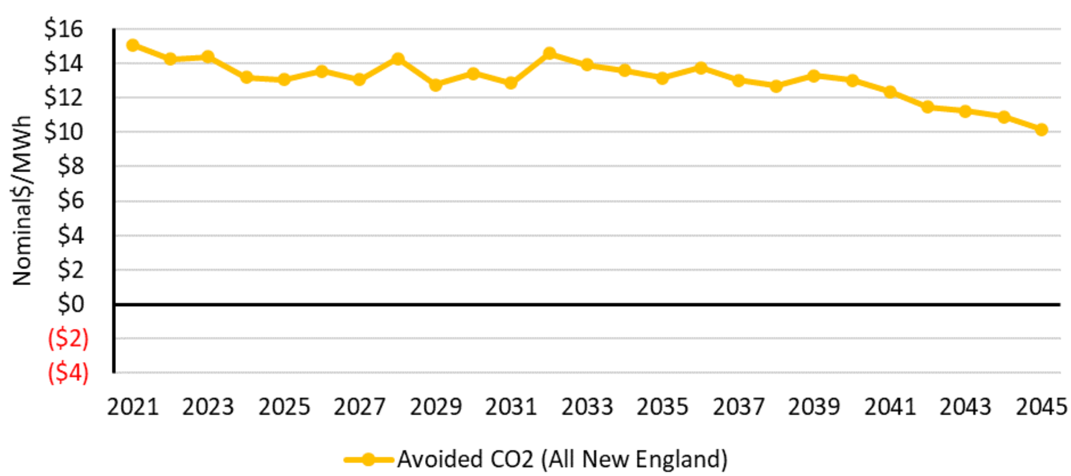


Figure 25: Average Annual Value of Avoided CO_2 per MWh of DER (UC3; nominal $)

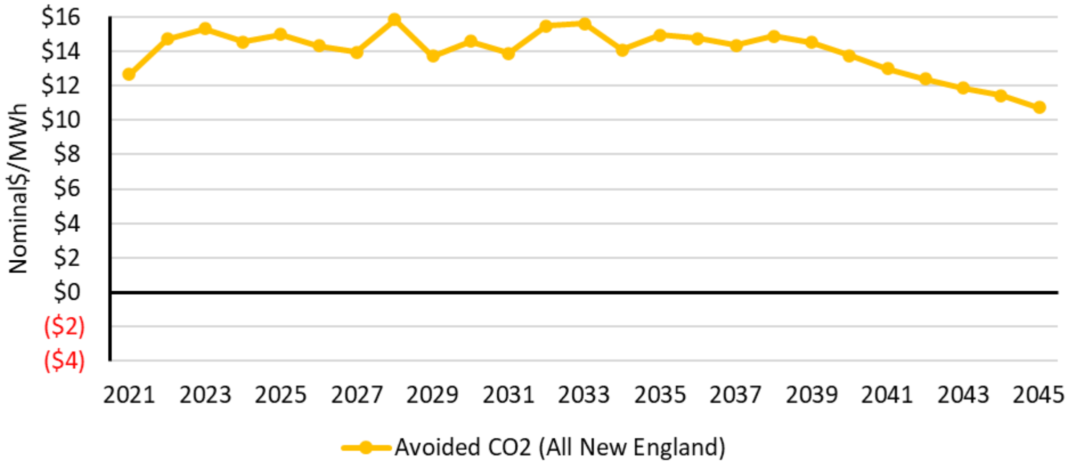


Figure 26: Average Annual Value of Avoided CO_2 per MWh of DER (UC4; nominal $)

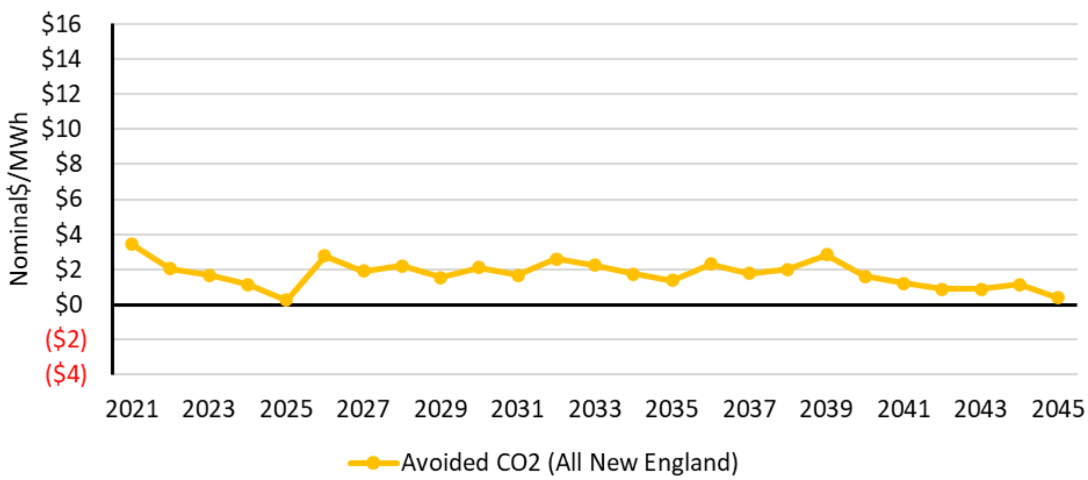


Figure 27: Average Annual Value of Avoided CO_2 per MWh of DER (UC5; nominal $)[66]

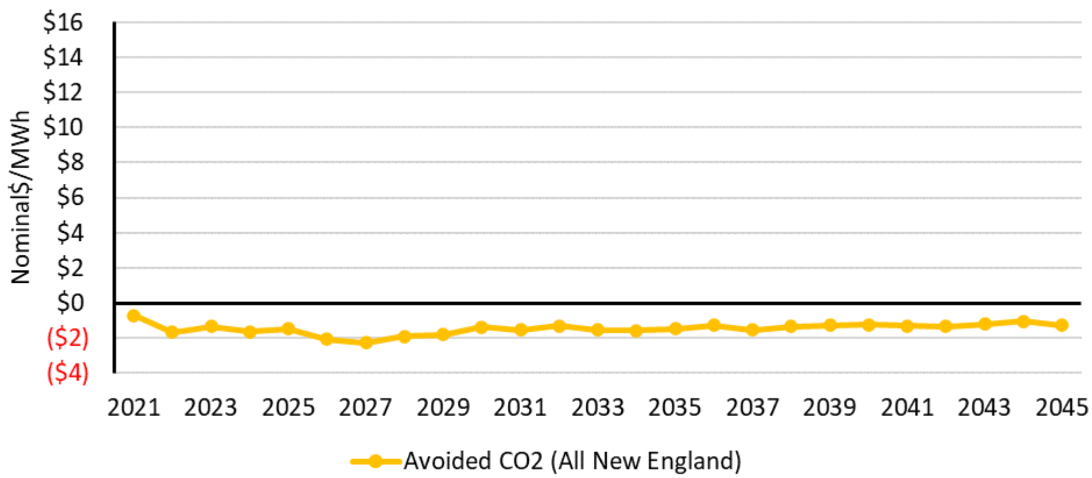
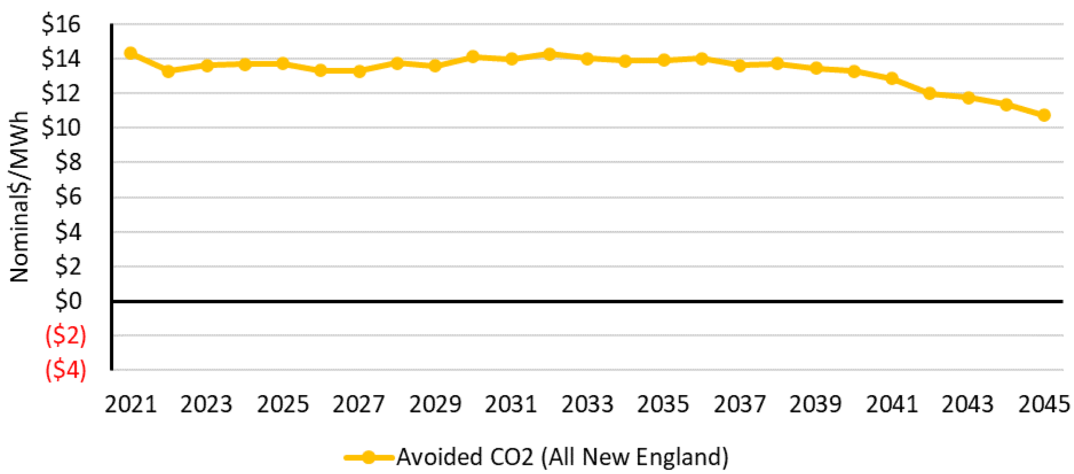


Figure 28: Average Annual Value of Avoided CO_2 per MWh of DER (UC6; nominal $)



The annual value of avoided NO_X, SO_2, and $PM_{2.5}$ emissions per MWh of DER at the state-level represents the difference between NO_X, SO_2, and $PM_{2.5}$ emissions in the Reference Case and each Use Case.[67] Avoided health effects associated with reduced emissions of NO_X, SO_2, and $PM_{2.5}$ within Connecticut were monetized using EPA's Technical Support Document, *Estimating the Benefit per Ton of Reducing $PM_{2.5}$ Precursors from 17 Sectors,* for NO_X, SO_2, and direct $PM_{2.5}$.[68] Values from this source document, presented in Table 9 as the total

---

[66] UC5 yielded a net increase in CO_2 emissions due to the emissions assumptions used for UC5, as detailed in Appendix B.

[67] The value of avoided NO_X, SO_2, and $PM_{2.5}$ emissions for each Use Case was calculated using the avoided state-level emissions, consistent with the state regulatory framework.

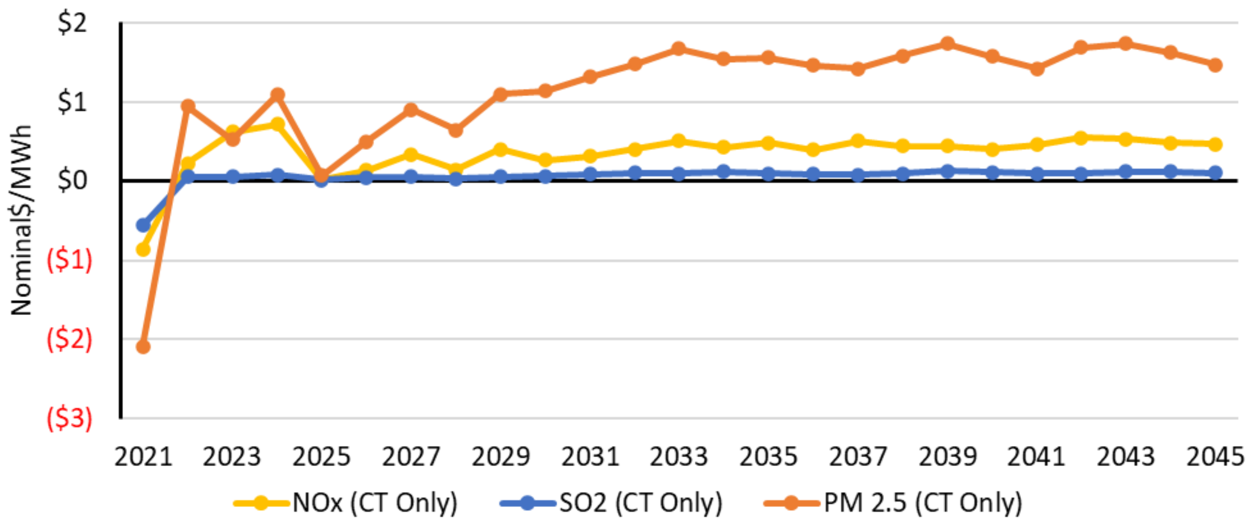
[68] U.S. Environmental Protection Agency (EPA), Technical Support Document Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors, dated February 2018, https://www.epa.gov/sites/production/files/2018-02/documents/sourceapportionmentbpttsd_2018.pdf. Values from Krewski, et al. (2009) provided in this document were used,

dollar value (mortality and morbidity) per ton of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors for electricity generating units, were converted to nominal dollars and extended over the forecast period using a simple linear extrapolation. Annual values of avoided NO_X, SO_2, and $PM_{2.5}$,emissions for each Use Case are shown in Figure 29 through Figure 34.[69]

Table 9: Dollar value per ton of directly emitted $PM_{2.5}$ and $PM_{2.5}$ precursors (2015$, 3 percent discount rate)

Year	NOx	SO_2	$PM_{2.5}$
2016	**$6,000**	**$40,000**	**$140,000**
2020	**$6,200**	**$42,000**	**$150,000**
2025	**$6,700**	**$46,000**	**$170,000**
2030	**$7,200**	**$49,000**	**$180,000**

Figure 29: Average Annual Value of Avoided NO_X SO_2, and $PM_{2.5}$ per MWh of DER (UC1; nominal $), Connecticut Only



consistent with other EPA reference. *See*, U.S. EPA, Sector-based PM2.5 Benefit Per Ton Estimates, https://www.epa.gov/benmap/sector-based-pm25-benefit-ton-estimates.

[69] The increase in emissions of NO_X and $PM_{2.5}$ in 2029 reflect the assumed retirement of Millstone. The variation in SO_2 emissions results from operation of coal units following the retirement of the Mystic units.

Figure 30: Average Annual Value of Avoided NO_X SO_2, and $PM_{2.5}$ per MWh of DER (UC2; nominal $), Connecticut Only

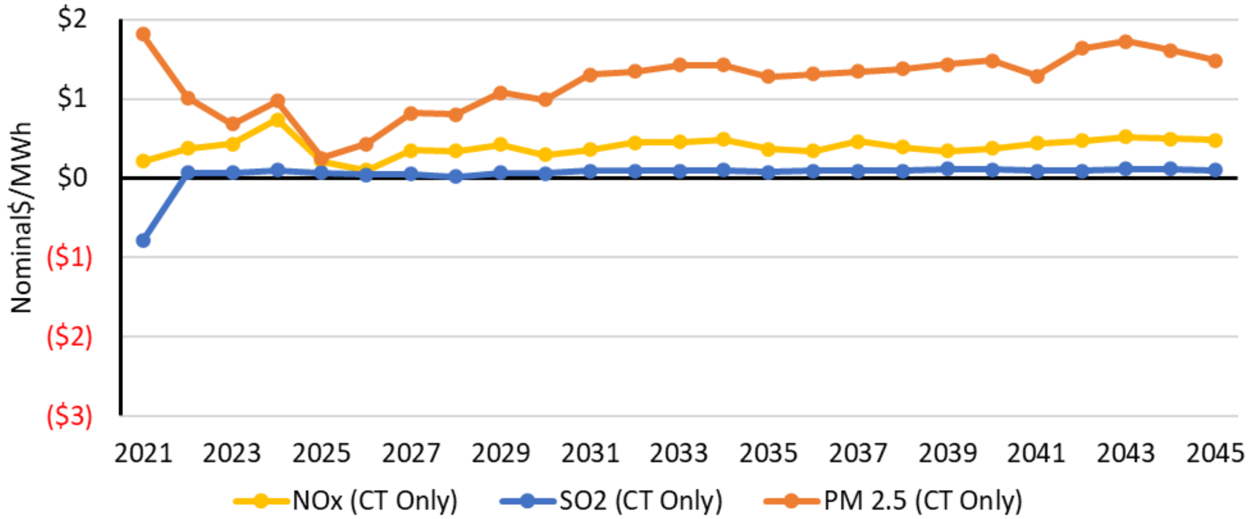


Figure 31: Average Annual Value of Avoided NO_X SO_2, and $PM_{2.5}$ per MWh of DER (UC3; nominal $), Connecticut Only

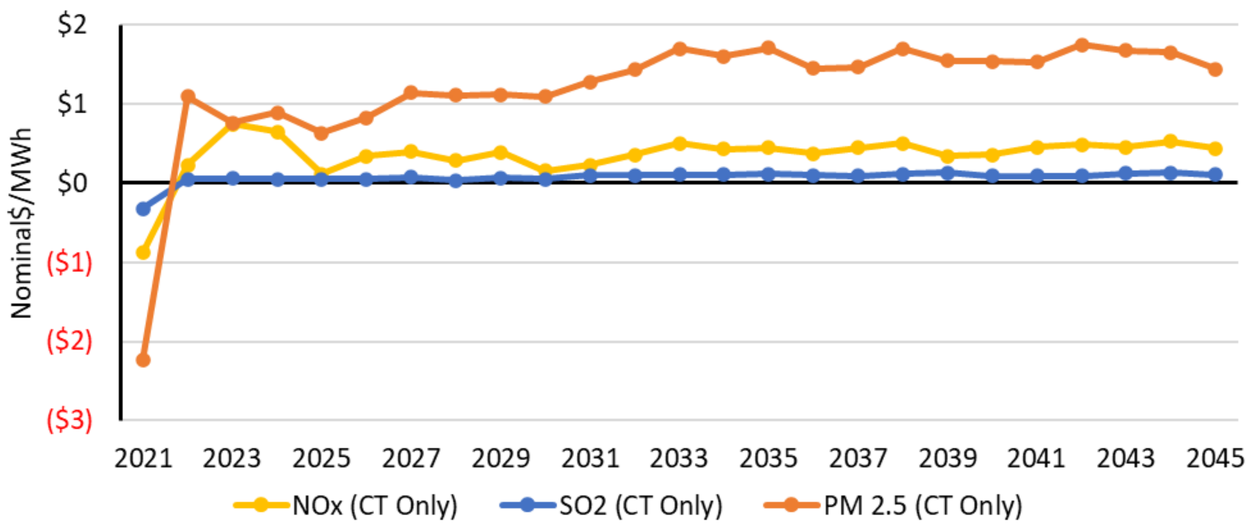


Figure 32: Average Annual Value of Avoided NO_X SO_2, and $PM_{2.5}$ per MWh of DER (UC4; nominal \$), Connecticut Only

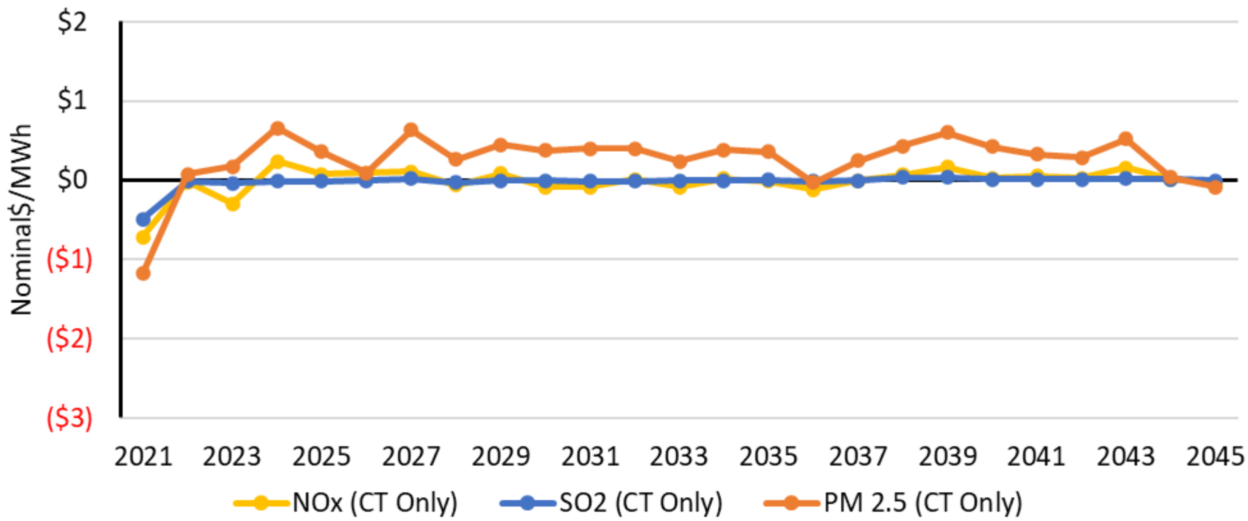


Figure 33: Average Annual Value of Avoided NO_X SO_2, and $PM_{2.5}$ per MWh of DER (UC5; nominal \$), Connecticut Only

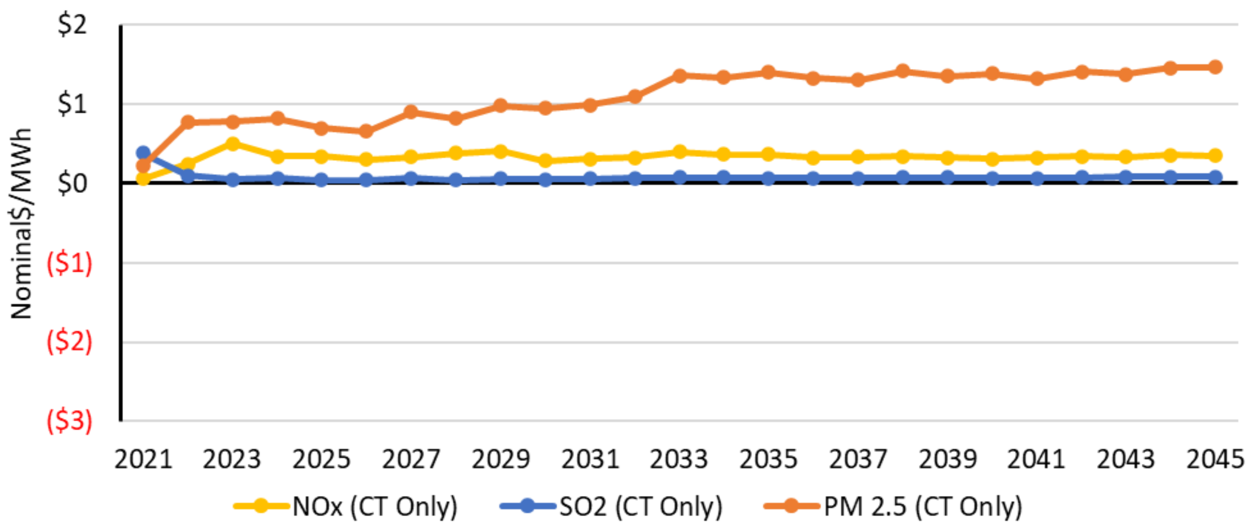
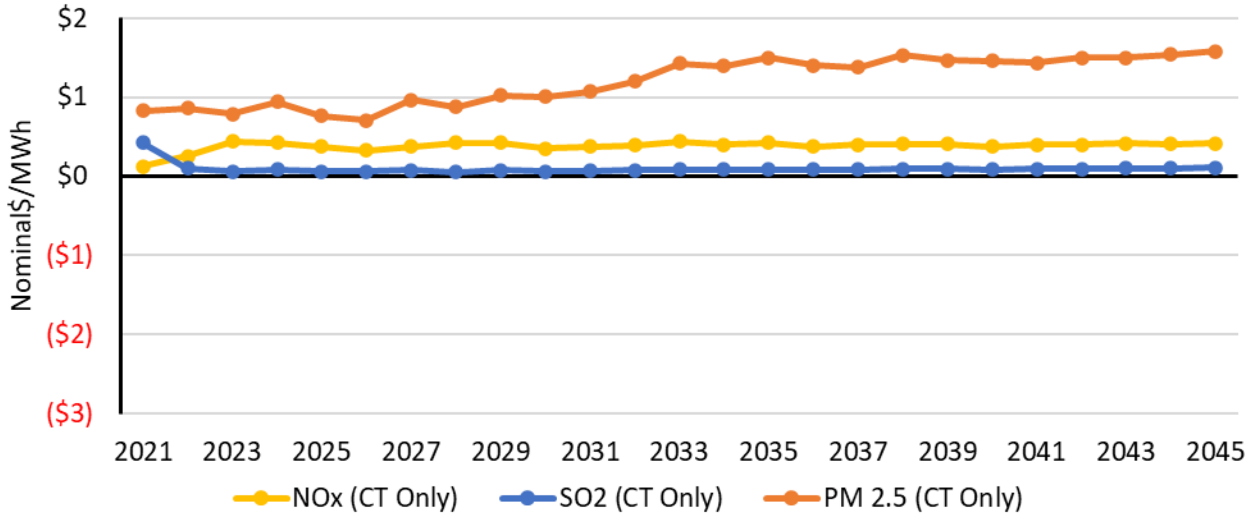


Figure 34: Average Annual Value of Avoided NO_X SO_2, and $PM_{2.5}$ per MWh of DER (UC6; nominal $), Connecticut Only



III. Discussion of Additional DER Value Categories

This Section qualitatively discusses and provides analysis on the following DER value categories based on the literature reviewed by the Agencies for the Study (continued from Section II.):[70] (4) macroeconomic costs and benefits; (5) distribution system costs and benefits; (6) resilience benefits; and (7) other health and environmental benefits. Table 10 details the DER value categories, and subcategories, specifically quantified and qualitatively discussed in this Section.

Table 10: DER Value Categories Included in Section III.

Electric System Impacts			
Transmission + Distribution	**Avoided T+D Line Losses**	**Qualitatively Discussed**	Cost impacts included in avoided energy costs; see Appendix B. for Use Case specific details
	Avoided Distribution Capacity	**Quantified**	Qualitatively discussed; quantification estimated
	Avoided Distribution O+M	**Qualitatively Discussed**	-
	Avoided Distribution Outages / Reliability	**Qualitatively Discussed**	-
	Distribution Voltage + Power Quality	**Qualitatively Discussed**	-
	Resilience Benefits	**Qualitatively Discussed**	-
Cost	**Integration Costs**	**Qualitatively Discussed**	Indicative costs included; tangential to Study scope
Societal Impacts			
Climate and Local Health Benefits	**Avoided Emissions (CO_2, NOx, SO_2, and $PM_{2.5}$)**	**Quantified**	Additional discussion of quantification
Other Societal Impacts	**Macroeconomic Costs + Benefits**	**Quantified**	Approaches from other studies included; some costs and benefits calculated
	Other Environmental + Health Benefits	**Qualitatively Discussed**	-

[70] For a list of literature reviewed for this Section and Study, more broadly, *See*, Docket No. 19-06-29, Notice of Admitted Evidence, dated September 17, 2019, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/c74187f194083fb785258478004e7a0b?OpenDocument. *See also*, Docket No. 19-06-29, Notice of Admitted Evidence, dated July 1, 2020.

Generally, this Section evaluates these DER value categories irrespective of technology and jurisdiction, but does provide technology- and jurisdiction-specific analysis where available. Ultimately, this Section provides some limited quantification of macroeconomic costs and benefits and adjustments to the quantification of avoided emissions benefits provided in Section II. These recommendations are combined with the analysis provided in Section II in the Summary Results in Section I.

Discussion of Macroeconomic Costs and Benefits

MACROECONOMIC COST AND BENEFIT OVERVIEW

Economic development benefits, also known as macroeconomic benefits, are among the many societal benefits provided by DERs. Such economic benefits provided by DERs include jobs, tax revenues, impacts on Gross Domestic Product (GDP), and general welfare.[71,72] These benefits can be classified as direct, indirect, and induced impacts.[73] Several examples are provided in Table 11 below.

Table 11: Categorization of Macroeconomic Benefits of DERs[74]

Direct Benefits	Indirect Benefits	Induced Benefits
- Land lease payments - Property tax payments - Construction jobs - O&M jobs - Local economic development commitments	- Increased demand for goods and services from direct beneficiaries - Accounting and legal personnel - Bank and financing	- Increased business at local restaurants and retail establishments - Child care - Misc. spending by direct and indirect beneficiaries

While many studies have attempted to quantify the societal benefits provided by DERs, such benefits are difficult to calculate, particularly economic development benefits. Most data on the social costs and benefits of DERs are assumption-driven and are heavily impacted by uncertainties.[75] As of May 2018, only three of the 15 states who have conducted value of DER studies made reference to economic development benefits, and only one attempted to quantify the value of economic benefits that DERs provide.[76,77] Most jurisdictions

[71] ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

[72] International Renewable Energy Agency, Renewable Energy Benefits: Measuring the Economics, dated 2016, https://www.irena.org/documentdownloads/publications/irena_measuring-the-economics_2016.pdf.

[73] National Renewable Energy Laboratory, Economic Development Benefits from Wind Power in Nebraska: A Report for the Nebraska Energy Office, dated November 2008, https://www.nrel.gov/docs/fy09osti/44344.pdf.

[74] *Id.*

[75] Grant Allan, et al., The Economics of Distributed Energy Generation: A Literature Review, https://pureportal.strath.ac.uk/files-asset/37429963/AllanEromenkoGilmartinKockarMcGregor_RSER_2014_Economics_of_distributed_energy_generation_1.pdf.

[76] ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

[77] *See*, Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

simply address the economic development benefits of DERs as a policy goal, discussing the forms of economic development benefits DERs can provide, such as job creation, reduced unemployment, tax revenue effects, land use optimization, and investment in the local economy. Some studies also point to consumer independence and freedom of choice as a benefit that can generate new capital, market competition, and increased customer engagement.

Included below is a review of the approaches other states and jurisdictions have taken to address the macroeconomic benefits of DERs, including a summary table of the macroeconomic costs and benefits evaluated by those jurisdictions. The examples herein are taken from ICF's May 2018, "Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar" and information provided by the Connecticut Green Bank (CGB). Ultimately, the literature review provided below is used to calculate an approximate value for the macroeconomic benefits provided by DERs in Connecticut.

STUDIES IN OTHER JURISDICTIONS

Arkansas

Soft Costs

In 2017, the Sierra Club commissioned a study on the benefits and costs of net metering as an intervening party in the Arkansas Public Service Commission's proceeding on net metering (Docket 16-027-R).[78] The Sierra Club study's primary argument for the inclusion of these benefits noted that "while distributed generation has higher costs per kW than central station renewable or gas-fired generation, a portion of their higher costs – principally for installation, labor, permitting, permit fees, and customer acquisition (marketing) – are spent in the local economy and thus provide a local economic benefit in close proximity to where the DG is located."[79] In other words, while other, central station power plants may have lower "soft" costs, the money invested in such generation facilities provide fewer direct economic development benefits to the local economy.

Citing the Lawrence Berkley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL) studies of the soft costs for distributed solar, the Sierra Club study presented estimates for the economic benefits likely to accrue in the local economy where a distributed solar installation is located. This analysis concluded that 22 percent of residential solar PV costs are expended in the local economy where a system is located, equating to $33.60/MWh of DER output. These estimates are displayed in Table 12.

---

[78] Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.
[79] *Id.*

Table 12: Examples of Residential Local Soft Costs[80]

Local Costs	LBNL		NREL	
	$/Watt	%	$/Watt	%
Total System Cost	6.19	100%	5.22	100%
Local Soft Costs				
Customer Acquisition	0.58	9%	0.48	9%
Installation Labor	0.59	10%	0.55	11%
Permitting + Interconnection	0.15	2%	0.10	2%
Permit Fees	0.09	1%	0.09	2%
Total Local + Soft Costs	1.41	22%	1.22	23%

Consumer Choice

Lastly, the Sierra Club's study cited "greater consumer choice" as a benefit of DERs. Specifically, it pointed to indirect benefits such as new sources of capital for clean energy and infrastructure, increased competition, technology synergy and adoption of other clean energy options, and increased customer engagement. However, the study did not attempt to provide a dollar value for this benefit but acknowledged that it would likely be "significant and positive," and would serve as an important policy reason for justifying net metering.

Mississippi

In 2014, the Public Service Commission of Mississippi commissioned Synapse Energy Economics, Inc. (Synapse) to study the costs, benefits, and policy considerations for net metering programs.[81] While this study primarily focused on the utility system costs and benefits, the study did acknowledge economic development benefits such as the siting, installation, maintenance, and resulting job impacts from various DER resources. For the estimates of jobs in particular, Mississippi pointed to a study conducted in Montana, noting that both states are rural. The findings of the Montana report are discussed below.

Montana

In 2014, the Montana Environmental Information Center, in conjunction with the Sierra Club, commissioned Synapse to evaluate the employment impacts of renewable energy investments in Montana.[82] The study employed IMPLAN, a standard economic input-output model, to estimate a cumulative employment impact per average MW by resource type.[83] This study found that in general, small-scale resources produce more jobs due to the effect of economies of scale, as shown in Table 13. For example, the study found that small-scale PV produces up to 9.2 jobs per average MW (aMW) per year versus 5.0 for large-scale PV.

---

[80] *Id.*

[81] Synapse Energy Economics, Inc., Net Metering in Mississippi: Costs, Benefits, and Policy Considerations, dated September 19, 2014, https://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[82] Synapse Energy Economics, Inc., Employment Effects of Clean Energy Investments in Montana, dated June 5, 2014, https://www.synapse-energy.com/sites/default/files/SynapseReport.2014-06.MEIC_.Montana-Clean-Jobs.14-041.pdf.

[83] It should be noted that IMPLAN represents all energy resources as one industry, which is an imprecise approximation as the operation and maintenance requirements of resources can differ significantly. Synapse Energy Economics, Inc. attempted to account for this imprecision by relying on resource-specific spending patterns produced by NREL's JEDI model.

Table 13: Average Annual Job Impacts by Resource per aMW (over 20 years)[84]

Resource Type	Construction (Jobs/aMW)	O&M (Jobs/aMW)	Total (Jobs/aMW)
Small PV	6.8	2.4	9.2
Large PV	3.5	1.5	5.0
Wind	0.7	0.7	1.5
Energy Efficiency	0.9	0.2	1.2

This study also used average annual wage assumptions by energy resource from NREL's JEDI model, adjusted for applicability in Montana, to estimate wages paid by resource type, as shown by in Table 14.

Table 14: Worker Wage Assumptions by Resource ($2012)[85]

Resource Type	Construction	O&M
Small PV	$55,000	$47,000
Large PV	$55,000	$47,000
Wind	$63,000	$47,000
Energy Efficiency	N/A	$47,000

It should also be noted that Synapse adjusted the IMPLAN model assumptions in order to reflect indirect and induced macroeconomic impacts. For indirect impacts, Synapse adjusted the "model's base resource spending allocation assumptions for the entire electric industry based on NREL data on requirements for each individual resource."[86] Synapse also assumed that not all materials used by DER developers would be purchased in-state.

For induced economic impacts, Synapse ran a "labor income" spending vector in the IMPLAN model to predict how income would be re-spent in the local economy. These adjustments enabled Synapse to produce an estimate of indirect or induced jobs associated with the installation of various clean energy resources, in addition to direct jobs, as shown in Table 15.

Table 15: Construction and Installation job Impacts in Job-Years per aMW[87]

Resource Type	Direct (Job-years/aMW)	Indirect/Induced (Job-years/aMW)	Total Construction (Job-years/aMW)
Small PV	26	110	136
Large PV	15	54	69
Wind	6	8	14
Energy Efficiency	13	6	19

---

84 Synapse Energy Economics, Inc., Employment Effects of Clean Energy Investments in Montana, dated June 5, 2014, https://www.synapse-energy.com/sites/default/files/SynapseReport.2014-06.MEIC_.Montana-Clean-Jobs.14-041.pdf.
85 *Id.*
86 *Id.*
87 *Id.*

New York

2014 Synapse Study

In 2014, the Advanced Energy Economy Institute (AEE Institute) also commissioned Synapse to conduct a Benefit-Cost Analysis for Distributed Energy Resources as a support resource for the New York Public Service Commission's "Reforming the Energy Vision" strategy planning process.[88] In its "universe" of relevant costs and benefits, Synapse included economic development and reduced tax burden under societal benefits.[89] This study was unique in that it acknowledged the challenges associated with monetizing the value of societal benefits, and provided a series of alternative approaches for regulators to use. These included proxies, benchmarks, regulatory judgement, and multi-attribute decision analysis.

For each cost and benefit included in the overall "universe," Synapse recommended approaching valuation through either monetization or one of the alternative methods, based on data availability and experiences in other jurisdictions. Synapse's recommended approaches for economic societal costs and benefits are demonstrated in Table 16.

Table 16: Recommended Valuation Approaches for Select Macroeconomic Cost and Benefits[90]

Perspective	Costs/Benefits		Valuation Method		
	Category	Specific Cost/Benefit	Monetization	Proxy	Multi-Attribute
Societal	Public Costs	State tax credits	Yes		
		Federal tax credits	Yes		
	Public Benefits	Economic Development			Yes
		Tax impacts from public buildings	Yes		

Of the set of economic costs and benefits included in the Synapse analysis, all but "Economic Development" was determined to be able to be monetarily valued, which is consistent with the other cited studies. In its report for AEE Institute, Synapse recommended that Economic Development be accounted for using multi-attribute decision analysis (MADA). This analysis enables all impacts and attributes of an option, whether monetized, quantified, or identified qualitatively, to be factored into a decision. Using a decision matrix, MADA summarizes the available data (i.e. net present value, quantity, or qualitative level) for each impact and attribute, and weights them by level of importance. These values can then be multiplied by their corresponding weight; the sum being the score for a particular option. Synapse provided a useful hypothetical example, shown in the Table 17 and Table 18.

---

[88] Synapse Energy Economics, Inc., Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for all Relevant Costs and Benefits, dated September 22, 2014, https://info.aee.net/benefit-cost-analysis-for-der-synapse.

[89] "Reduced Tax Burden" reflects reduced local tax burden due to lower operating costs in public buildings from lower electric utility bills.

[90] Synapse Energy Economics, Inc., Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for all Relevant Costs and Benefits, dated September 22, 2014, https://info.aee.net/benefit-cost-analysis-for-der-synapse.

Table 17: Raw Data for Hypothetical Multi-attribute Decision Analysis[91]

Raw Data	NPV of Monetized Costs and Benefits		Non-Monetized Environmental Benefits		Contribution to Market Animation		Non-Monetized Benefits to Participants	
	Millions $	*Weight*	*Qual. Score*	*Weight*	*Qual. Score*	*Weight*	*Qual. Score*	*Weight*
Alternative A	$1.54	0.60	Low (=1)	0.20	Low (=1)	0.15	Low (=1)	0.05
Alternative B	$1.10	0.60	Medium (=2)	0.20	Medium (=20	0.15	Low (=1)	0.05
Alternative C	$0.87	0.60	High (=3)	0.20	High (=3)	0.15	Medium (=2)	0.05

Table 18: Normalized Data and Overall Scores[92]

Normalized Data	NPV of Monetized Costs and Benefits		Non-Monetized Environmental Benefits		Contribution to Market Animation		Non-Monetized Benefits to Participants		Overall Score
	Millions $	*Weight*	*Qual. Score*	*Weight*	*Qual. Score*	*Weight*	*Qual. Score*	*Weight*	
Alternative A	$0.44	0.60	0.17	0.20	0.17	0.15	0.25	0.05	0.33
Alternative B	$0.31	0.60	0.33	0.20	0.33	0.15	0.35	0.05	0.32
Alternative C	$0.25	0.60	0.5	0.20	0.5	0.15	0.5	0.05	0.35

While this approach enables non-monetized or quantified benefits to be easily incorporated into a decision analysis, it should be noted that the weighting and attributes to be included must be carefully considered in order to prevent manipulation or unintended outcomes.

2012 NYSERDA Study

The New York State Energy Research and Development Authority (NYSERDA) released the New York Solar Study in 2012. The Power New York Act of 2011 directed NYSERDA to prepare a study that evaluated the costs and benefits of increasing solar PV in New York to 5,000 MW by 2025. Uniquely, this study not only estimated the economic benefits of solar PV, but also the costs. For example, the study projected the number of jobs created by meeting the 5,000 MW goal, but also the economy-wide jobs lost due to the "loss of discretionary income [from increased electric rates due to a solar subsidy] that would have otherwise supported employment in other sectors of the economy."[93] Additionally, the study estimated that the Gross State Product would actually be reduced by $3 billion through 2049 at an annual rate of -0.1 percent.

91 *Id.*
92 *Id.*
93 New York State Energy Research and Development Authority, New York Solar Study: An Analysis of the Benefits and Costs of Increasing Generation from Photovoltaic Devices in New York, dated January 2012, https://www.nyserda.ny.gov/-/media/Files/Publications/Energy-Analysis/NY-Solar-Study-Report.pdf.

NYSERDA used a REMI PI+ model of the New York economy to estimate these effects. While the net jobs impact was not incorporated into the cost-benefit analysis, this attempt to quantify the economic development costs of DERs is consistent with the "Symmetry Principle" of the NSPM, and can help provide a more complete picture of the impacts of investment in solar PV.[94]

Connecticut

In 2016, the Connecticut Green Bank stated in its Evaluation Framework that it would track the extent to which investments in clean energy create value from a societal perspective as it relates to the economic development of the state.[95] Accordingly, the Connecticut Green Bank, in conjunction with the Department of Economic and Community Development (DECD), and with assistance from the utilities, contracted Navigant Consulting to create an updated jobs calculator in order to estimate economic development benefits generated by in-state clean energy investments.[96] The output value of this calculator is "job-years created per $1 million invested in clean energy projects in Connecticut."[97] The calculator primarily estimates direct jobs employed by Connecticut companies and uses a multiplier for indirect and induced jobs. The report found that, in 2016, Connecticut had approximately 5,300 direct jobs in the renewable energy and energy efficiency industry with roughly 2,800 direct jobs in the energy efficiency industry, 1,300 direct jobs in the solar PV industry, and roughly 1,100 direct jobs in the fuel cell industry.

SUMMARY TABLE AND QUALITATIVE ANALYSIS

Table 19 provides a summary of the macroeconomic cost and benefit categories evaluated in the studies detailed above, providing some illustrative calculations based on Connecticut-specific data. The table also highlights the relevant studies and evaluation methodologies discussed above for each category. Lastly, it is important to note that some, although not all, of the categories listed are mutually exclusive. For example, "Local Soft Costs" can be used to approximate the value of the DER jobs in a given jurisdiction. As such, it overlaps with the "Jobs Created" category.

---

[94] National Efficiency Screening Project, National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources, dated 2017, https://nationalefficiencyscreening.org/national-standard-practice-manual/.

[95] Connecticut Green Bank, Evaluation Framework: Assessing, Monitoring, and Reporting of Program Impacts and Process, dated July 2016, pp. 21-23, https://ctgreenbank.com/wp-content/uploads/2017/02/CTGreenBank-Evaluation-Framework-July-2016.pdf.

[96] Connecticut Green Bank, Evaluation Framework: Societal Perspective Fact Sheet, dated 2016, https://www.ctgreenbank.com/wp-content/uploads/2018/03/CGB_DECD_Jobs-Study_Fact-Sheet.pdf.

[97] Navigant Consulting, Inc., Clean Energy Jobs in Connecticut: Final Report, dated August 10, 2016, https://www.ctgreenbank.com/wp-content/uploads/2017/02/CTGReenBank-Clean-Energy-Jobs-CT-August102016.pdf.

Table 19: Macroeconomic Cost-Benefit Framework for DERs[98]

	Costs/Benefits			Applicable Valuation Method(s)	
Category	**Specific Cost/Benefit**	**Units**	**Est. Value**	**Model/Report**	**NY MADA (see above)**
Societal Costs	State Tax Credits/Incentives	$	-	Program Specific	-
	Example: LREC/ZREC	$	*$120M/yr*		-
	Example: RSIP	$	*$0.53/watt*		-
	Jobs Lost	# jobs	-	REMI Model	Yes
Societal Benefits	Jobs Created	# jobs	-	CGB Report	Yes
	Direct Jobs	# jobs	-	CGB Report	Yes
	Indirect/Induced Jobs	# jobs	-	CGB Report	Yes
	OR Local Soft Costs (est. value of jobs)	$/MWh; $/watt	$30/MWh; $0.83/watt	NREL Study; Jurisdiction Specific	-
	Customer Acquisition	$/watt	*$0.33/watt*	NREL Study; Jurisdiction Specific	-
	Installation Labor	$/watt	*$0.37/watt*	NREL Study; Jurisdiction Specific	-
	Permitting & Interconnection	$/watt	*$0.07/watt*	NREL Study; Jurisdiction Specific	-
	Permit Fees	$/watt	*$0.06/watt*	NREL Study; Jurisdiction Specific	-
	Property Tax Revenues	$	-	Jurisdiction Specific	-
	Tax Impacts from Public Buildings	S/kWh	-	Jurisdiction Specific	-
	Gross State Product	$	-	REMI Model	-

Based on the studies reviewed and the above table, the Agencies provide the following qualitative discussion on the macroeconomic impacts of DER deployment in Connecticut focusing on the impacts on the state as a whole, and not to any specific customer or participant. Where possible, the Agencies have attempted to provide quantification of the impacts. Any analysis provided below should be viewed as a starting point for further development.

State Tax Credits

While tax credits or other incentives reduce upfront costs to program participants, they can increase the cost burden for other ratepayers and/or taxpayers. Therefore, these can be considered a societal cost and may vary depending on the technology being considered. However, as discussed below, this cost leads to direct jobs and investments in the state.

The above framework includes the estimated costs of the 15-year zero emission renewable energy credit (ZREC) and low emission renewable energy credit (LREC) contracts statutorily required by Public Act 11-80. Public Act 19-35 extended this program by two years and authorized the utilities to spend $8 million per

[98] See the summaries of the reviewed studies above for more details regarding the "Applicable Valuation Method(s)."

year on new 15-year contracts.[99] Over the course of the LREC and ZREC programs, up to $1,200,000,000 in program funds could be distributed to operational DERs in Connecticut.

The above framework also includes the costs of providing incentives offered through the Residential Solar Investment Program. Since the program's inception in 2012, incentives have averaged $0.53 per Watt.[100] With a statutory sunset of 350 MW, this program's total macroeconomic cost is conservatively estimated at $185,500,000.

Jobs Lost and Created

The Connecticut Green Bank's 2018 "Evaluation Framework: Societal Perspective Fact Sheet" states: "In FY 2016 there was a total investment of $240 million in Residential Solar PV in Connecticut. Through the Connecticut Green Bank's support, over 936 direct and 312 indirect and induced job-years were created in the state from installing nearly 60 MW of Residential Solar PV."[101]

Property Tax Revenues

While none of the studies reviewed above attempted to quantify increased property tax revenues as a societal macroeconomic benefit, numerous studies have analyzed the effects of DERs on property value. In a 2019 study, FreddieMac found that new homes with RESNET (i.e. an energy efficient home) were sold at a price premium of 2.7 percent more than comparable unrated homes.[102] Similarly, a 2015 LBNL study using the standard appraisal method for property valuation found that owned solar PV systems on single-family homes across six states garnered an average premium of $3.78/W indicating that the presence of DERs on a property can increase its value, and therefore the amount of tax revenue it generates for a local economy.[103]

While research into the effects of DERs on property value is increasing, there has yet to be a Connecticut-specific study that spans multiple technologies. Therefore, while property tax revenue benefits have the potential to be monetized, they should be valued qualitatively at this time given current available data.

Local Soft Costs

The inclusion of soft costs allows Connecticut to quantify at least some of the impacts DER investment has on the local economy. The study conducted in Arkansas referenced a 2013 NREL study for soft cost

---

99 Public Act 19-35, An Act Concerning a Green Economy and Environmental Protection, dated June 28, 2019, https://www.cga.ct.gov/2019/ACT/pa/pdf/2019PA-00035-R00HB-05002-PA.pdf.

100 Connecticut Green Bank, RSIP Transition Webinar: 300 MW Target, Post-RSIP Market, dated January 15, 2019, https://ctgreenbank.com/wp-content/uploads/2019/01/RSIP-Transition-Webinar_011519.pdf.

101 Connecticut Green Bank, Evaluation Framework: Societal Perspective Fact Sheet, dated 2016, https://www.ctgreenbank.com/wp-content/uploads/2018/03/CGB_DECD_Jobs-Study_Fact-Sheet.pdf.

102 R. Argento, Energy Efficiency: Value Added to Properties and Loan Performance, dated 2019, https://sf.freddiemac.com/content/_assets/resources/pdf/fact-sheet/energy_efficiency_white_paper.pdf.

103 Lawrence Berkeley National Lab, Appraising into the Sun: Six-State Solar Home Paired-Sales Analysis, dated November 12, 2015, https://emp.lbl.gov/publications/appraising-sun-six-state-solar-home.

estimates.[104] Not to be confused as societal costs, Arkansas assumed that four of the nine soft cost categories (customer acquisition, installation labor, permitting and interconnection, and permit fees) included in the NREL study would result in direct spending in the local economy and therefore should be considered macroeconomic benefits.[105] In 2018, NREL released an updated benchmarking study for solar PV system costs that estimated soft costs would be 63 percent of total system costs; consistent with the 2013 study, despite variation over the previous five years.[106]

However, the 2018 NREL study does not provide cost estimates for each individual soft cost category as it did in 2013. Therefore, the numbers provided by the Agencies in the above table utilize the total system cost proportions assigned to each soft category in 2013, paired to a current system cost estimate. While the 2018 NREL study estimated a national average system cost for residential systems of $2.70/watt, the Agencies determined that it is more relevant, in this instance, to use the average system cost provided by the Connecticut Green Bank's Residential Solar Investment Program (RSIP) Annual Legislative Report at $3.57/watt.[107] Costs, such as installation labor costs, are general higher in Connecticut than the rest of the nation as shown by U.S. Bureau of Labor Statistics; thus, indicating it is reasonable to assume a higher average system cost for Connecticut.[108] This is also consistent with the 2018 NREL study, which found that Massachusetts, New Jersey, and New York all had average per watt costs higher than the national average.[109]

Thus, the values for soft costs provided in above table were calculated by applying the proportions of total system costs for each soft cost category from the 2013 NREL study to the average system cost per watt as calculated by the Connecticut Green Bank.

Further, consistent with the methodology used in the Arkansas study, a simple $/MWh macroeconomic benefit can be calculated using the capacity factor for BTM solar PV calculated for UC1 of the Study, along with other UC1 assumptions, specifically an annual panel degradation of 0.5 percent per year and an assumed 25-year solar PV system life.[110] Such a calculation yields a $30/MWh estimate for macroeconomic benefits.

---

[104] National Renewable Energy Laboratory, Benchmarking Non-Hardware Balance-of-System (Soft) Costs for U.S. Photovoltaic Systems, Using a Bottom-Up Approach and Installer Survey-Second Edition, dated October 2013, https://www.nrel.gov/docs/fy14osti/60412.pdf.

[105] Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

[106] National Renewable Energy Laboratory, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018, dated November 2018, https://www.nrel.gov/docs/fy19osti/72399.pdf.

[107] Connecticut Green Bank, Progress Report on the Connecticut Green Bank Residential Solar Investment Program, dated January 11, 2019, https://www.ctgreenbank.com/wp-content/uploads/2019/01/RSIP-Legislative-Report-2019.pdf.

[108] U.S. Bureau of Labor Statistics, May 2019 State Occupational Employment and Wage Estimates: Connecticut, https://www.bls.gov/oes/current/oes_ct.htm#49-0000

[109] National Renewable Energy Laboratory, U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018, dated November 2018, https://www.nrel.gov/docs/fy19osti/72399.pdf.

[110] See Appendix B. for greater detail regarding UC1 (Use Case 1).

Tax Impacts from Public Buildings

In the unique case of public building participation in DER programs, benefits effectively accrue back to all taxpayers or ratepayers, depending on the public building. Public buildings that are able to reduce utility costs through DER implementation can reduce overhead and thereby more efficiently allocate tax dollars to other uses or reduce tax burden on the public. It is challenging to track this information definitively.

SUMMARY

Existing Connecticut policy documents identify economic development as a priority for the state, and it is frequently cited as a co-benefit of Connecticut energy and climate policies.[111,112,113] The Agencies carefully reviewed the studies summarized above to evaluate how to reflect the macroeconomic benefits provided by DERs into the Study and into future studies, reports, and proceedings the Agencies may conduct. The Agencies recognize the need for more study in this area, and particularly on the economic impacts of energy policy decision making on underserved and historically overburdened residents, communities and businesses. The Agencies are committed to more equitable and inclusive access to clean and affordable energy and to careers in clean energy, and are engaging on this issue in a variety of pending proceedings and venues, including, but not limited to, Docket No. 17-12-03RE01, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Energy Affordability,[114] the C&LM Planning process, the GC3, and the State's development and implementation of the Shared Clean Energy Facility (SCEF) Program in Docket Nos. 19-07-01 and 19-07-01RE01.[115] Ultimately, the Agencies recognize that the macroeconomic benefits of DERs to Connecticut are very likely positive and, with a focused and inclusive approach, can be realized across the demographics of Connecticut's ratepayers, and as such, provide the following quantification as a proxy pending further study.

Estimated Net Economic Development Benefit

A $30/MWh estimate for macroeconomic benefits of BTM solar PV was calculated based on the specific methodology used in the Sierra Club commissioned study in Arkansas. The same methodology can be

---

[111] Connecticut Department of Energy and Environmental Protection, Comprehensive Energy Strategy: CT General Statutes Section 16a-3d, dated February 8, 2018, https://portal.ct.gov/-/media/DEEP/energy/CES/2018ComprehensiveEnergyStrategypdf.pdf?la=en.

[112] Governor's Council on Climate Change, Building a Low Carbon Future for Connecticut: Achieving a 45% GHG Reduction by 2030, dated December 18, 2018, https://portal.ct.gov/-/media/DEEP/climatechange/publications/BuildingaLowCarbonFutureforCTGC3Recommendationspdf.pdf?la=en

[113] Connecticut Department of Economic and Community Development, Economic Development Strategy, dated May 2018, https://portal.ct.gov/-/media/DECD/Research-Publications/ED_StrategyPlans/2018_strategic_plan.pdf?la=en

[114] *See*, Docket No. 17-12-03RE01, PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Energy Affordability, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=17-12-03RE01.

[115] Under the Modified SCEF Program Requirements, at least 60 percent of the program output must be subscribed to low-income customers, moderate-income customers, or affordable housing facilities, *See*, Docket No. 19-07-01, Review of Statewide Shared Clean Energy Facility Program Requirements, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=19-07-01. *See also*, Docket No. 19-07-01RE01, Review of Statewide Shared Clean Energy Facility Program Requirements – Customer Enrollment, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=19-07-01RE01.

used to calculate macroeconomic costs based on the average RSIP incentive of $0.53/watt listed above. Such a calculation yields a $19.4/MWh estimate for macroeconomic costs, ultimately yielding a net macroeconomic benefit for BTM solar PV of $10.6/MWh.

The above estimated net macroeconomic benefit calculation should be viewed as a rough estimate, particularly in light of the detailed description of the macroeconomic cost-benefit categories for DERs provided above. However, for the purposes of the Study, and in the absence of a more detailed and precise analysis, the Agencies have included this net macroeconomic benefit calculation as a proxy in the Summary Results in Section I. While the Agencies applied this proxy across all six Use Cases, the Agencies do not believe that the economic benefits of each DER technology are equivalent, but believe that the inclusion of such a proxy is preferable to no quantification whatsoever.

Discussion of Distribution System Costs and Benefits

Assessing the value of DERs to the distribution system requires an analysis of all of the components that are impacted by each type of DER. Provided below is an overview of existing approaches to quantify or otherwise consider distribution system impacts of DERs, beginning with an overview of distribution system categories impacted by DERs based on the literature review conducted for the Study and including Connecticut-specific data where available. Subsequently, an overview of existing approaches used by other jurisdictions to determine distribution system impacts is provided, along with a summary of the approach taken by UI in the Localized Targeting of Distributed Energy Resources project approved in the Decision dated January 24, 2018, in Docket No. 17-06-03, Application For Review Of The United Illuminating Company's Distributed Energy Resource Integration Plan. Finally, current approaches are analyzed to determine their usefulness and relevance in quantifying distribution system costs and benefits for the Study.

COST AND BENEFIT CATEGORIES OVERVIEW

Avoided Distribution Capacity Costs

The distribution category most often cited as benefiting from the deployment of DERs is the potential for the reduction of peak load on substation and circuit feeders, which can result in potential avoided capacity-related investments. The value of avoided capacity-related investments from the deployment of DERs is sensitive to locational and load growth and the temporal coincidence of DERs with system loads on distribution feeders and substations.[116] Avoided distribution capacity costs are a function of other factors, including the penetration level of DERs. However, high levels of DER penetration typically require increased distribution capacity in order to safely and reliably host DERs. To ensure that DERs actually add value for a particular distribution system, visibility into distribution system operations is needed.[117] In most

[116] ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, p. 15, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

[117] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, p. 151, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

current approaches, methods to determine the avoided distribution capacity-related investments overlook the locational factors (up to combining avoided distribution capacity costs with avoided transmission costs) to minimize complexity by determining a system-wide value.

Reduced Line Losses

DERs placed near distribution system loads generally reduce power line losses if voltage drop due to line length (or distance) is reduced by the addition of a generation source in a radial feeder. Since voltage is held constant, line losses are a function of current and resistance so line losses increase as load on the system increases, and are thus largest at times of peak load. Therefore, both strategic location and timing of generation help reduce line losses. A Study performed in Maryland found the average line losses from bulk generation sources, through the transmission system and out to end users on the distribution system to be 15 percent.[118]

While placing generation near loads will generally reduce line losses, there are other factors to consider, such as loss contributions for energy efficiency and other factors added by the introduction of a new generator (*e.g.* voltage and frequency flicker, reverse power flow, etc.).[119] Locational power flow studies are needed to accurately determine whether power loss benefit is achieved on a feeder.[120]

The Study, as discussed in Appendix B., used 6.5 to 8 percent to approximate the combined avoided transmission and distribution line losses attributable to DERs.[121] Table 20 provides a summary of the annual distribution system losses for Connecticut's electric distribution companies (EDC), the Connecticut Light & Power Company d/b/a Eversource Energy (Eversource) and the United Illuminating Company (UI).

Table 20: Annual Connecticut EDC Distribution Line Losses[122]

	Year	Retail Sales (MWh)	Distribution System Requirements (MWh)	Distribution Energy Losses (MWh)	Distribution Energy Losses (%)
UI	2017	5,093,904	5,245,010	151,106	2.9%
	2018	5,191,279	5,337,597	146,318	2.7%
	2019	4,978,256	5,111,782	133,526	2.6%
Eversource	2017	21,611,697	22,352,401	740,704	3.3%
	2018	22,020,420	22,789,335	768,915	3.4%
	2019	23,085,320	23,641,192	555,872	2.4%

118 *Id.*, pp. 92-93.
119 *Id.*, p. 132.
120 *Id.*, p. 133.
121 As illustrated in Table 1, and elsewhere in the Study, the avoided cost impacts associated with reduced line losses were incorporated into the results presented in Section II.
122 *See*, Docket No. 19-06-29, Interrogatory Responses, dated June 9 and 10, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/015c8114587c6cf58525858300644c2e?OpenDocument.

Combined EDCs	2017	26,705,601	27,597,411	891,810	3.2%
	2018	27,211,699	28,126,932	915,233	3.3%
	2019	28,063,576	28,752,974	689,398	2.4%

Reduced Operations and Maintenance Expenses

Reducing distribution capacity at various parts of a circuit (such as feeders and substations) can reduce the wear and tear on that infrastructure and, thus, avoid some operations and maintenance (O&M) costs to maintain the equipment.[123] As load on a circuit segment nears system capacity, thermal dissipation requirements increase on the devices, accelerating the loss of equipment service life.[124]

This category also includes the possibility for service life extension of distribution plant.[125] Frequent mechanical operation of load tap changers, capacitor switches, and other devices due to large variations in daily load profiles accelerates the loss of life of those devices.[126]

It should be noted, however, that uncontrolled DERs such as solar PV, while generally beneficial due to its contribution to reducing system peak, may actually induce the same types of effects, ultimately requiring more activation of devices and increasing capacity at the ends of the system during times of light loading.[127] Accordingly, in order to achieve the O&M savings that may be theoretically possible, DERs may need to be controlled to eliminate reverse power flow and adverse impacts to system loading. Sufficient level of control may be achieved with effective use of smart inverters, but further study is required to quantify the benefits attributable to smart inverters, as they have not yet been used in sufficient quantities to determine such benefits.

Distribution Voltage and Power Quality

Electric distribution companies are required to maintain voltage and frequency within certain operating limits. DERs may require additional investment by the EDCs or in connecting customers to maintain system power and voltage within specified levels. As stated above, smart inverters paired with solar PV can provide

---

[123] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, p. 134, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

[124] *Id.*

[125] New Hampshire Public Utilities Commission, Value of Distributed Energy Resources Study: Scope and Timeline Report, Docket DE 16-576, dated May 8, 2018, p. 9, https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2018-05-09_STAFF_VDER_STUDY_SCOPE_TIMELINE_RPT.PDF.

[126] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, p. 134, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

[127] *Id.*

support to the distribution grid by regulating generator voltage and frequency and improving grid power factor or other power quality measures.[128]

Avoided Reliability-Based Outages[129]

DERs may enhance reliability through reducing the frequency, duration, or magnitude of customer outages. Further discussion regarding resilience benefits is provided in a subsequent part of this Section. The discussion here refers to reliability-based outages not due to extreme outage events (*e.g.* extreme weather-related outages), but rather due to day-to-day operational-related outages that are characterized by a limited duration. For example, an increase in customer load can lead to overloaded substation transformers, distribution feeders, and service transformers, which can present reliability issues if unresolved.[130] Upgrades may be costly and, in the event of unexpected failure, additional costs may be incurred due to environmental remediation. DERs may help resolve potential overloads by reducing capacity on a given part of the distribution system.

Integration and Interconnection Costs

The utility or interconnecting customers typically incur a cost to interconnect DERs safely and reliably onto the distribution system. Infrastructure upgrades may be needed for proper power and voltage quality, upgraded transformers, metering, and protection against unintentional islanding and other faults.[131] Integration costs may also include administrative and engineering costs related to the interconnection of DERs.

While DER integration and interconnection can incur costs, it is important to note that the interconnection costs paid for by DER developers will sometimes be in place of planned upgrades, meaning that DER customers are providing a benefit to other ratepayers in paying for an upgrade that would have otherwise fallen to ratepayers more generally. Furthermore, interconnection costs paid by DER developers provide benefits to other DER developers that may wish to interconnect on that portion of the distribution grid.

To provide a sense of scale, Table 21 provides a summary of the DER integration costs incurred annually between 2015 and 2019. The majority of the costs provided below are borne by the interconnecting DER system owner and, thus, were not borne by ratepayers. As such, interconnection costs were not included in the quantitative analysis of the Study.[132]

---

[128] ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, p. 16, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

[129] The Agencies note that this category may overlap with the reduced O&M expenses category.

[130] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, pp. 135-136, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

[131] ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, p. 16, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

[132] See Section I. for greater discussion of the Study purpose and scope.

Table 21: Annual Connecticut EDC DER Interconnection Costs Incurred[133]

	Year	#	kW	Incurred Cost ($)	Average Annual Incurred Cost per kW ($/kW)
UI	2015	1,014	16,319	$1,640,367	$101/kW
	2016	1,729	41,911	$1,745,665	$42/kW
	2017	1,528	15,679	$1,990,795	$127/kW
	2018	1,952	25,781	$1,713,832	$66/kW
	2019	2,670	26,425	$2,597,100	$98/kW
	Avg.	**1,779**	**25,223**	**$1,937,552**	**$77/kW**
Eversource	2015	6,032	77,897	$3,672,846	$47/kW
	2016	6,068	79,166	$4,380,029	$55/kW
	2017	3,877	94,888	$6,905,280	$72/kW
	2018	4,241	103,543	$11,607,282	$112/kW
	2019	5,750	115,238	$3,335,624	$28/kW
	Avg.	**5,194**	**94,146**	**$5,980,212**	**$63/kW**
Combined EDCs	2015	7,046	94,216	$5,313,213	$56/kW
	2016	7,797	121,077	$6,125,694	$51/kW
	2017	5,405	110,567	$8,896,075	$80/kW
	2018	6,193	129,324	$13,321,114	$103/kW
	2019	8,420	141,663	$5,932,724	$42/kW
	Avg.	**6,972**	**119,369**	**$7,917,764**	**$66/kW**

Avoided Land Use for Distribution Lines and Field Devices

To the extent that DERs may help avoid the expansion of substation or circuit feeders, they may also reduce the amount of additional land required for the upgrade.[134] One study found that on average, area needs for a substation expansion of one transformer and three circuits is approximately 0.25 acres.[135] Acquiring property rights, easements, and performing environmental studies all add costs to distribution system operations.

---

[133] Both EDCs noted limitations in the data sets provided, *See*, Docket No. 19-06-29, Interrogatory Responses, dated June 9 and 10, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/015c8114587c6cf58525858300644c2e?OpenDocument.

[134] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, p. 137, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

[135] *Id.*

REVIEW OF STUDIES PERFORMED

Only a few studies to date have determined quantitative values for the costs and benefits that DERs provide to the distribution system. In a review of 15 jurisdictions, ICF's report prepared for the U.S. Department of Energy found that eight states determined values for avoided distribution capacity and six determined values associated with interconnection costs category.[136] Of the eight studies that included avoided distribution capacity in their analysis, only two included the value as a standalone figure, the remaining including it with avoided transmission capacity costs.[137] Four jurisdictions calculated values to account for avoided distribution operations and maintenance costs.[138] For the remaining categories considered in the studies reviewed by ICF, specifically, distribution voltage and power quality, distribution line losses, and avoided reliability and resilience, the report found that those categories were either: (1) not evaluated at all; or (2) considered on a qualitative basis only.[139]

D.C. and Arkansas Studies

The two studies that included avoided distribution system capacity costs separately from avoided transmission capacity costs were conducted for the District of Columbia and for Arkansas. Both studies determined a system-wide avoided capacity cost value that ignored any locational and temporal dependent factors.[140] The District of Columbia study determined the avoided distribution capacity costs from solar PV to be $167.27/MWh.[141] The value was derived from its operating utilities' marginal distribution capacity costs and a reduction in the system peak based on solar PV attributes and coincidence at peak.[142] The report acknowledged that this value should only be used for high-level system-wide estimates and that it does not apply to avoided costs at the feeder level.[143] The Arkansas study determined the avoided distribution capacity cost provided by solar PV to be $94/MWh.[144] The study acknowledged that the estimate was tied only to avoided capacity costs due to load growth and noted that other factors, such as conservation voltage reduction and power quality, may add additional value if they can be better understood.[145]

---

136 ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, pp. 15-16; 19, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

137 *Id*., pp. 15; 21.

138 *Id*.

139 *Id*.

140 *Id*., p. 32.

141 Synapse Energy Economics, Inc., Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting, dated April 12, 2017, p. 126, https://www.synapse-energy.com/sites/default/files/Distributed-Solar-in-DC-16-041.pdf.

142 *Id*.. p. 125.

143 *Id*.

144 Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, p. 19, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

145 *Id*.

California/PG&E Study

A study performed by the Energy Institute at Haas analyzed a representative sample of Pacific Gas and Electric's (PG&E's) distribution feeders in northern California and found that when considered across the entire distribution system, capacity deferrals, on average, amounted to a small fraction of value relative to the installed cost of solar PV, largely due to the lack of capacity need or potential load growth on most feeders.[146]

The PG&E study found that roughly 10 percent of feeders required capacity projects over a ten-year period.[147] For system-wide capacity deferral values, the study produced a range from 0.05¢/kWh to 0.7¢/kWh.[148] Applying the value of solar PV to the 10 percent of feeders that were likely to need upgrades in the next 10 years, the value of DERs on those feeders increased roughly fivefold to between 0.25¢/kWh and 3.5¢/kWh.[149] It should be noted that these value ranges were assuming lower solar PV penetration levels and that diminishing returns on the value is seen as the penetration level is increased on a feeder.[150] The study also found minimal to no increase in expected costs to manage operational issues such as voltage regulation (increase use of load tap changers, or maintaining voltage limits) or transformer overloading associated with the deployment of DERs.[151]

Other State Studies

Recent studies conducted in Maryland, New Hampshire, New York, and California established frameworks for determining the locational capacity values for avoided or deferred capacity projects.[152] The reports stipulate that locational cost studies for specific capacity investments are necessary to determine the distribution system value of various DERs.[153] The study performed by the Maryland Commission did allow for the hypothetical savings for avoided system capacity costs in the range of a few cents to tens of cents per kWh of energy produced by the DER, but ultimately found that locational cost studies of specific capacity investments would be necessary to determine the value of various DERs.[154] These locational

---

[146] Energy Institute at Haas, Economic Effects of Distributed PV Generation on California's Distribution System, dated June 2015, p. 2, https://haas.berkeley.edu/wp-content/uploads/WP260.pdf.

[147] *Id.,* p. 13.

[148] *Id.*, p. 12.

[149] *Id.*

[150] *Id.*, p. 13.

[151] *Id.*, pp. 7; 15-16.

[152] New Hampshire Public Utilities Commission, Value of Distributed Energy Resources Study: Scope and Timeline Report, Docket DE 16-576, dated May 8, 2018, p. 9, https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2018-05-09_STAFF_VDER_STUDY_SCOPE_TIMELINE_RPT.PDF. Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, pp. 132, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf. ICF, Review of Recent Cost-Benefit Studies Related to Net Metering and Distributed Solar, dated May 2018, pp. 44-46, https://www.icf.com/-/media/files/icf/reports/2019/icf-nem-meta-analysis_formatted-final_revised-1-17-193.pdf.

[153] *Id.*

[154] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, pp. 162, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

distribution value of DER studies in each of jurisdictions are at various stages of completion, but are all still in progress as, generally, such studies require substantial additional analysis.

The New York methodology includes a twofold approach to determine avoided distribution capacity values:

1. A "Demand Reduction Value," a system-wide value using marginal Cost of Service studies to calculate the value to the distribution system of reducing demand during distribution peaks.
2. A "Locational System Relief Value," to be determined by utilities and will identify high-value locations on the distribution system and apply a uniquely determined incentive for each location.[155]

LOCALIZED TARGETING OF DISTRIBUTED ENERGY RESOURCES METHODOLOGY

UI provided the following summary of the Demonstration Project Rate Rider (DPDRR) developed to incentivize the deployment of DERs through the Localized Targeting of DERs project approved in Docket No. 17-06-03:[156]

> The basis of the proposed DPDRR is a known, quantitative deferred capacity investment at Ash Creek substation that may otherwise be needed as early as 2018 as a result of a reduction in circuit peak from DERs installed during the demonstration project…The expected reduction in circuit peak is then translated into a per kWh customer incentive based on several assumptions, including measured solar PV peak coincidence factors for Connecticut PV systems during the defined summer peak period.

UI provides an estimated cost of $625,000 for the known, quantitative deferred capacity investment at the Ash Creek substation, which would provide a total of 4.9 MW of capacity relief, yielding a cost of $127.55/kW of capacity relief. UI also estimates that a 7 kW (DC) solar PV system would provide, on average, 2.8 kW of capacity relief during the summer peak period (between 2pm and 6pm). Multiplying 2.8 kW times $122.55/kW yields an approximate capacity relief value of $354 for a 7 kW (DC) solar PV system over the five-year planning horizon. Ultimately, UI translates this into a DPDRR rate of $0.053 per kWh for the summer peak period during the relevant five-year planning horizon by dividing $354 by the expected summer peak period production of the solar PV system.

---

[155] State of New York Public Service Commission, Staff Report on the Collaborative Regarding Community Distributed Generation for Low-Income Residential Customers, Case 15-E-0082 – Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions for Implementing a Community Net Metering Program, August 15, 2016, pp. 36-37, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={BC894273-8816-4447-A689-892B72CDC09E}.

[156] Docket No. 19-06-29, EL-7 Interrogatory Response, Attachment 1, dated June 9 and 10, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/015c8114587c6cf58525858300644c2e?OpenDocument.

Table 22 uses UI's methodology to provide a rough approximation of the value DERs can provide in deferring known, discrete capacity investments for each of the Use Cases defined in Section II. and in Appendix B.[157] Specifically, the Agencies looked at the approximate value that the DER modeled deployment in 2021 for each Use Case could provide in deferred distribution system capacity over a five-year planning period (2021-2025). The following data is also provided in Table 22 and used to calculate the deferred distribution system capacity value described above: the cost per capacity relief used for the DPDRR, \$127.55/kW; the total Study period cumulative avoided generation capacity provided in Table 7 divided by 10 (years) to calculate the 2021 avoided distribution capacity cost for each Use Case; and the total 2021 generation for each Use Case provided in Appendices B.I. through B.VI.[158]

Table 22: Estimated Deferred Distribution Capacity Value by Use Case

	2021 Avoided Capacity (MW)	Differed Investment Over Study Period ($)	Annual Generation, Modeled 2021 DER Deployment (MWh)	Annual Unitized Dist. Capacity Benefit (2021-2025)[159]
UC1	25.3	$3,227,015	116,369	$0.0055/kWh
UC2	34.0	$4,336,700	161,148	$0.0054/kWh
UC3	66.8	$8,520,340	113,900	$0.0150/kWh
UC4	100.0	$12,755,000	149,242	$0.0171/kWh
UC5	93.8	$11,964,190	821,264	$0.0029/kWh
UC6	100.0	$12,755,000	876,000	$0.0029/kWh

The above analysis includes many assumptions, such as: zero DER system degradation over the five-year planning period; systems provide the same avoided capacity benefit throughout the relevant planning period; all DERs are located on feeders that would defer distribution system capacity upgrades; and the value of the deferred capacity upgrades are homogeneous. These simplifying assumptions are in addition to the simplifying assumptions UI's methodology inherently include. Nonetheless, the above analysis does provide some insight into the approximate value DERs can provide in deferring distribution system capacity upgrades.

---

[157] The EDCs identified \$2.8 million in capacity upgrades that may have been deferred between 2017 and 2019 through a reduction in load on specific feeders, *See*, Docket No. 19-06-29, Interrogatory Responses, dated June 9 and 10, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/015c8114587c6cf58525858300644c2e?OpenDocument.

[158] For UC4, the gross dispatched or discharged energy from the modeled FTM electric storage systems was used.

[159] Unlike UI's DPDRR rate calculation, the Agencies' analysis annualizes the \$/kWh calculation to provide an apples-to-applies comparison with the value of DER quantification provided elsewhere in the Study.

SUMMARY

Avoided Distribution Capacity

While some jurisdictions have determined a value associated with distribution capacity deferrals, most of the current literature reveals that the location and timing of energy production and delivery of DERs plays a crucial role in determining whether the specific DER adds value or costs to the electric distribution system.

Location-specific variables that determine the cost or benefit any DER can provide include: the load growth rate, peak day load profiles, the type of DER, the age and capacity of feeders and transformers, etc.[160] For example, while all DERs have the potential to avoid distribution capacity upgrades, if a DER is interconnected to a circuit with low load, the distribution system may require additional infrastructure that would not otherwise be needed at the time of interconnection.[161] The timing of DER interconnections is also important, as capacity system upgrades typically add substantial capacity at substantial cost.[162] Including DER-based capacity additions, then, complicates the benefit analysis since traditional resource planning adds capacity in large "blocks," whereas DER capacity comes in small increments.[163] Therefore, while the incremental capacity offered by DERs adds value to the distribution system, there is substantial uncertainty around when and if the capacity value is fully realized.

Likewise, distribution system capacity, if not sufficient to export DER generation, can be a limiting factor in DER deployment, threatening reliability, which, in turn, requires the upgrade of existing system infrastructure and incurs additional costs.[164]

Maryland identified the importance of load growth in realizing the value of avoiding or deferring capacity-based upgrades.[165] Maine, in its analysis of the value of solar PV, did not factor in any distribution capacity costs recognizing that peak load growth was not expected to grow for the foreseeable future.[166] Notably, the

---

[160] Docket No. 19-06-29, Eversource Written Comments, August 21, 2019, p. 4.

[161] *Id.*

[162] Docket No. 19-06-29, UI Written Comments, August 21, 2019, p. 4.

[163] Interstate Renewable Energy Council, Inc., A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, dated October 2013, p. 25, http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf. Docket No. 19-06-29, UI Written Comments, August 21, 2019.

[164] Institute for Policy Integrity, New York University School of Law, Getting the Value of Distributed Energy Resources Right, dated December 3, 2019, https://policyintegrity.org/files/publications/Getting_the_Value_of_Distributed_Energy_Resources_Right.pdf.

[165] Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, p. 126, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

[166] Maine Public Utilities Commission, Maine Distributed Solar Valuation Study, dated April 14, 2015, p. 41, https://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

Maine study was published prior to Maine's commitment to decarbonize its economy.[167] Those decarbonization goals may have more of an impact on peak demand than was anticipated at the time of the study. The study of PG&E's distribution feeders in northern California found that when considered across the entire distribution system, capacity deferrals, on average, amounted to a small fraction of value relative to the installed cost of solar PV, largely due to the lack of capacity need or potential load growth on most feeders.[168]

Based on the foregoing, the Agencies' current understanding is that the locational and temporal factors affecting distribution capacity must be precisely understood to accurately capture the value that DERs provide to the distribution system. While the Agencies attempted to estimate the distribution system benefits DERs can provide in deferring capacity-related upgrades on specific feeders, those benefits are highly dependent on specific application. The Agencies do not currently have sufficient locational or temporal data to provide an accurate quantification of the distribution system benefits attributable to the different DERs evaluated in the Study.

Other Distribution System Costs and Benefits

There is little consensus concerning whether DERs provide benefits or induce costs with respect to the other categories of distribution system impacts discussed above. DERs certainly provide benefits to the distribution system including through voltage and frequency disturbance ride-through capability offered by current advanced inverters.[169] Ride-through capability reduces the likelihood of cascading DER disconnections due to transmission or distribution faults. However, this is a good example of the complexity of determining distribution system costs and benefits attributable to DERs, as such capability also represents a cost incurred by inverter-based DERs

As discussed above, non-dispatchable DERs generally increase the operational complexity of the distribution system and therefore increase costs to interconnect to the distribution system. Interconnection costs and system operating costs are expected to increase as penetration levels of those types of DERs increase.[170] There is, however, conflicting evidence showing that even at high solar penetration levels in northern California, minimal to no increase in costs should be expected to manage operational issues such as voltage regulation (increase use of load tap changers, or maintaining voltage limits) or transformer overloading.[171]

---

[167] See, Governor Janet Mills, An Order to Strengthen Maine's Economy and Achieve Carbon Neutrality by 2045, dated September 23, 2019, https://drive.google.com/file/d/0B_W8V6ab5O57YjQzRHNMeVpjUXdwd2ttUkZiQ3ZBMnRXS0NB/view.

[168] Energy Institute at Haas, Economic Effects of Distributed PV Generation on California's Distribution System, dated June 2015, p. 2, https://haas.berkeley.edu/wp-content/uploads/WP260.pdf.

[169] Interstate Renewable Energy Council, Inc., A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, dated October 2013, p. 30, http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.

[170] Docket No. 19-06-29, Eversource Written Comments, August 21, 2019, p. 7.

[171] Energy Institute at Haas, Economic Effects of Distributed PV Generation on California's Distribution System, dated June 2015, pp. 7;15-16, https://haas.berkeley.edu/wp-content/uploads/WP260.pdf.

Further, operational issues that do arise may be avoided with the intentional use of electric storage systems along with solar, which has the ability to mitigate some of the costs.[172]

While practically all of the categories of distribution system benefits provided by DERs require further study, the approaches taken in New Hampshire, California, and Maryland provide guidance on how best to identify and incorporate into a valuation framework these categories of DER values. The processes each have laid out require substantial additional study in conjunction with the distribution utilities to identify specific locational and temporal characteristics of the system and accurate locational and temporal modeling of various power flows of the distribution system. One study is underway to consider the contribution of solar and wind DERs on distribution system line loading using actual Connecticut historical circuit data.[173] This is one example where the results would be immensely helpful to the Agencies to include in valuation of DERs on the distribution system. Unfortunately, for the purposes of the Study, such data is not currently available. Instead, the Agencies will look to the example of other states' processes in evaluating next steps in valuing the distribution system benefits that DERs can provide.

Discussion of Resilience Benefits

Resilience, as it relates to the distribution of electricity, may be defined as the ability of the electric distribution system to resist, absorb and adapt, and recover after an external high impact, low-probability shock.[174] The National Association of Regulatory Utility Commissioners (NARUC) has adopted a similar definition of resilience: the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event.[175] These definitions of resilience distinguish it from reliability in that reliability focuses on high-probability but low impact disruption events, whereas resilience targets severe disruptions such as major storms.[176]

DERs provide three categories of resilience value: those that accrue directly to the customer, those that accrue to the community, and those that accrue to the utility distribution system. There is often overlap

---

172 Daymark Energy Advisors, RLC Engineering, and ESS Group, Benefits and Costs of Utility Scale and Behind the Meter Solar Resources in Maryland, dated November 2, 2018, pp. 161-161, https://cleantechnica.com/files/2018/11/MDVoSReportFinal11-2-2018.pdf.

173 M. Ovaere and K. Gillingham, The Heterogeneous Value of Solar and Wind Energy: Empirical Evidence from the United States and Europe, dated December 5, 2019, https://drive.google.com/file/d/1I-sp4fUwUlW4WR3WdzEPXAz5e6AQvS7E/view.

174 Institute for Policy Integrity, New York University School of Law, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System, dated August 1, 2018, p.4, https://policyintegrity.org/files/publications/Toward_Resilience.pdf.

175 National Association of Regulatory Utility Commissioners, The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, dated April 2019, p. 7, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

176 Institute for Policy Integrity, New York University School of Law, Getting the Value of Distributed Energy Resources Right, dated December 3, 2019, p.22, https://policyintegrity.org/files/publications/Getting_the_Value_of_Distributed_Energy_Resources_Right.pdf.

between categories, seen most clearly in the example of microgrids, where benefits may be provided to both customers and the community at large. This section will consider existing approaches to determine the value of DERs for all three resilience categories.

RESILIENCE CATEGORY OVERVIEW

Customer Benefit

DERs that provide a resilience benefit directly to a customer, such as a private company or residential customer, allow service to operate during extended power outages and, thus, provide value to that customer. Accordingly, the resilience benefit to customers in this instance is equivalent to the value of avoided outages that can be attributed to the DER. A number of methodologies exist to quantify the value of avoided outages. A NARUC review of approaches to valuing DER resilience considered a number of "bottom-up" approaches, which look to assign resilience value to individual customers based on their preferences or behavior.[177] These preferences can either be stated by customers in interviews and surveys, or by an analysis of real-world customer behavior that is then translated to a kind of resilience posture.[178] Another method, employed by Avangrid's New York utilities, determines the value of avoided outage for various customer classes based on using the retail rate as a proxy for determining the customer's value of the loss of service.[179]

While these methodologies are useful tools for understanding the resilience value of DERs, as customer resilience benefits do not directly flow to the electric system or other ratepayers or citizens, this category of resilience benefits are outside the scope of the Study.

Community Resilience Benefits

Community resilience benefits generally are considered in two distinct categories: (1) the effects of power disruptions on regional and local economies; and (2) maintaining critical facilities (first responders, shelters, etc.) during major power disruptions.[180] Microgrids are the primary way this resilience value is captured.

Many jurisdictions consider DER-based microgrids and emergency generation as the sole applications of DERs to resilience.[181] However, regulatory proceedings seeking to value resilience benefits in microgrids

---

[177] National Association of Regulatory Utility Commissioners, The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, dated April 2019, p. 17, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

[178] *Id.*

[179] NYSEG and RG&E, Benefit Cost Analysis (BCA) Handbook Version 1.1, dated August 22, 2016, p. 57, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF0CC59D0-4E2F-4440-8E14-1DC07566BB94%7D.

[180] National Association of Regulatory Utility Commissioners, The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, dated April 2019, pp. 17-18, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

[181] New Hampshire Public Utilities Commission, Value of Distributed Energy Resources Study: Scope and Timeline Report, Docket DE 16-576, dated May 8, 2018, p. 13, https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2018-05-09_STAFF_VDER_STUDY_SCOPE_TIMELINE_RPT.PDF. National Association of

have not yet quantified these benefits in a usable way.[182] Attempts to justify resilience expenditures in the form of microgrids have relied on qualitative discussions of benefits and have faced barriers such as the inability of all ratepayers to take advantage of microgrids and the fact that many critical facilities have existing back-up generation.[183]

Methodologies exist which quantify some level of community resilience benefit. LBNL developed an Interruption Cost Estimate calculator (ICE) which estimates the avoided cost of power interruptions for specific customer types in different parts of the country and for different durations. This value could be applied to microgrid participants who avoid outages, but not to the community at large. ICE has a value of reliability, which can estimate power interruption costs, but the tool is not designed to capture the value of avoided outages for long duration events as is defined by resilience.[184]

Another methodology that has been designed to capture regional economic impact is the IMPLAN model. The tool models how the regional economy can be affected by, among other events, long-term duration interruptions.[185] IMPLAN essentially quantifies how changes in productivity in one sector (electric distribution) can impact the regional economy.[186] The model has difficulty calculating any meaningful economic impact value attributable to small DERs, but can be applied to larger microgrids.

A third methodology that can be applied to microgrids and provides a means to evaluate community resilience has been developed by the Federal Emergency Management Agency.[187] The model estimates costs associated with degradation to fire, police, and other critical services due to interruption of electrical service. The costs associated with critical services are based on assumptions about the value of lives saved and injuries prevented. Into required for this model include detailed locational information about the critical facilities under questions. For example, for a fire station served by a microgrid, the following information would be needed to determine the damage estimate due to loss of electrical service: population served by fire station, distance to nearby fire stations, and annual number of incidents handled by the station, among others.[188]

Since the inputs to the methodologies are so specific, they do not lend themselves to developing a universal quantitative value for community resilience. Application of this methodology would require evaluation of specific microgrid proposals.

Regulatory Utility Commissioners, The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, dated April 2019, p. 15, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

[182] National Association of Regulatory Utility Commissioners, The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, dated April 2019, p. 15, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

[183] *Id.*, p. 11.

[184] *Id.*, p. 22.

[185] *Id.*, p. 25.

[186] *Id.*

[187] Federal Emergency Management Agency, FEMA Benefit-Cost Analysis Re-engineering (BCAR): Development of standard economic values (Version 6.0), dated December 2011, https://files.hudexchange.info/course-content/ndrc-nofa-benefit-cost-analysis-data-resources-and-expert-tips-webinar/FEMA-BCAR-Resource.pdf.

[188] *Id.*, pp. 13-14.

Unfortunately, none of the above methodologies are appropriate for use in the Study. First, they apply mostly to microgrids and not DERs as a whole, and do not apply to all ratepayers and Connecticut citizens more broadly. However, the Agencies recognize the immense value that microgrids and other DERs can provide by safely islanding critical facilities such as firehouses, police stations, community shelters, and schools. The above methodologies may serve as useful resources in calculating the community resilience benefits of microgrids and DERs if and when appropriate.

Utility Resilience Benefits

A literature review revealed only one effort to quantify or qualitatively identify the resilience benefit DERs provide to a utility's distribution system. This finding is consistent with current thought that resilience benefits typically flow either directly to the customers served by the DER or to a community through microgrids.

The Avangrid utilities in New York State developed a methodology to model the net avoided restoration costs that could be calculated during a major outage instance that effectively determines the avoided costs of sending a crew to a trouble spot.[189] That report found that it is unlikely that DER investments will limit or replace the need to repair distribution system infrastructure after a storm, and so only applies the methodology to certain non-DERs.[190] It may be reasonable to expect some level of reduction in restoration costs if restoration activities can be delayed enough to allow restoration crews to perform work during regular shifts. However, as the methodology does not currently apply to DERs, it did not aid in the Agencies' efforts to quantify utility resilience benefits provided by DERs in the Study.

SUMMARY

A comprehensive literature review indicates that a standardized approach does not exist for the calculation of resilience value.[191]

The Institute of Policy Integrity New York University School of Law (IPI) offered a general methodology to determine the resilience value that DERs provide. IPI's methodology require the ability to determine the following: (1) characterize potential sources of disruptions; (2) specify metrics (along with associated uncertainty) for resilience that are measurable according to source of disruption; (3) quantify baseline system

[189] NYSEG and RG&E, Benefit Cost Analysis (BCA) Handbook Version 1.1, dated August 22, 2016, p. 55, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF0CC59D0-4E2F-4440-8E14-1DC07566BB94%7D.

[190] *Id.,* p. 57.

[191] National Association of Regulatory Utility Commissioners, The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices, dated April 2019, p. 28, https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

resilience; (4) characterize how DERs modify system resilience from the baseline condition; and (5) compare the benefits and costs of DERs in terms of resilience.[192]

This highlights the challenge to quantifying the benefits that resilience provides. No model reviewed by the Agencies for the Study meets all of the steps outlined by IPI. Further, the value of resilience depends on a multitude of assumptions including risks of extended outages, the avoided resilience costs, and the ability of the DER to add to existing distribution system resilience.[193] Finally, as indicated earlier, the Study does not quantify participant benefits for any value category; including a quantification of the customer benefits for resilience would go against the NSPM principle of symmetry. Accordingly, the Agencies did not quantify the resilience value provided by DERs in the Study, but instead provide the foregoing analysis as a resource for valuing specific DER applications that provide customer or community resilience.

Discussion of Environmental and Health Benefits

Section II provided quantification of avoided CO_2, NO_X, SO_2, and $PM_{2.5}$ emissions attributable to the deployment of DERs through specific Aurora dispatch model analysis performed for the Study and attempted to assign an economic value to the climate and health benefits provided by avoiding such emissions. To supplement that analysis, the Agencies reviewed other relevant studies to ensure that the Study's analysis accurately reflects the most recent attempts to quantify the environmental and health benefits associated with DERs. Below is a qualitative discussion of that literature review, the conclusion of which results in an adjustment to the quantification of avoided emissions benefits provided in Section II.

CLIMATE BENEFITS

The SCC is a commonly used approach to quantifying the economic benefits of avoided CO_2 emissions attributable to the deployment of clean and distributed energy resources. Specifically, SCC is "a measure, in dollars, of the long-term damage done by a ton of carbon dioxide emissions in a given year."[194] The most widely cited estimates are those produced by a U.S. federal Interagency Working Group (IWG) during the Obama Administration. The IWG's central estimate is $51 per metric ton of carbon dioxide emitted in 2020,

---

192 Institute for Policy Integrity, New York University School of Law, Getting the Value of Distributed Energy Resources Right, dated December 3, 2019, p.23, https://policyintegrity.org/files/publications/Getting_the_Value_of_Distributed_Energy_Resources_Right.pdf.

193 Interstate Renewable Energy Council, Inc., A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, dated October 2013, p. 31, http://www.irecusa.org/wp-content/uploads/2013/10/IREC_Rabago_Regulators-Guidebook-to-Assessing-Benefits-and-Costs-of-DSG.pdf.

194 U.S. EPA, The Social Cost of Carbon: Estimating the Benefits of Reducing Greenhouse Gas Emissions, https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html.

rising incrementally to $85 per metric ton in 2050, at a discount rate of three percent (2018 dollars).[195,196] Estimates of SCC have been criticized because of the methodological limitations of the underlying economic analyses. A recent critique of the IWG's estimate concludes:

> Effects such as increased fire risk, slower economic growth, and large-scale migration are all unaccounted for, despite their potential to cause large economic losses. So, policymakers should account for these omissions by treating the Social Cost of Carbon figures presented within [the interagency] report as underestimates.[197]

Subsequent estimates of SCC that attempt to address, in part, these methodological limitations include:

- A 2014 metanalysis concluding that $133/metric ton was a "lower bound" for SCC (2018$)[198]; and
- A 2015 study estimating that a figure of ~$143/ metric ton in 2020 (2018$) would be consistent with the values and assumptions employed by a surveyed set of 365 economists "who have published [one or more articles] related to climate change in a highly ranked, peer-reviewed economics or environmental economics journal since 1994." The authors note that a SCC estimate of this magnitude "could have profound implications for climate policy decisionmaking."[199]

The standard procedure for incorporating SCC (or cost of avoiding GHG emissions) in DER valuation is to deduct compliance costs associated with GHGs (e.g., those imposed via RGGI), framing this as SCC, net of compliance obligations.[200] Compliance costs are incorporated instead in the calculation of avoided energy cost.

---

195 *Id*. The Interagency Working Group estimated impacts in 2007$. The 2018 figures cited here are from: Institute for Policy Integrity, New York School of Law, 2019, Opportunities for Valuing Climate Impacts in U.S. State Electricity Policy, dated April 2019, p. 9, https://policyintegrity.org/files/publications/Valuing_Climate_Impacts.pdf.

196 The Trump administration, in contrast, has proposed a value of $1 to $7 per ton that disregards the impacts of U.S. emissions beyond the nation's borders and uses a higher discount rate. *See*, Brad Plumer, Trump Put a Low Cost on Carbon Emissions; Here's Why It Matters, dated August 23, 2018, https://www.nytimes.com/2018/08/23/climate/social-cost-carbon.html. In a 2017 executive order, the Trump administration also disbanded the Interagency Working Group. *See*, Presidential Executive Order on Promoting Energy Independence and Economic Growth, dated March 28, 2017, https://www.whitehouse.gov/presidential-actions/presidential-executive-order-promoting-energy-independence-economic-growth/.

197 Institute for Policy Integrity, New York School of Law, 2019, Opportunities for Valuing Climate Impacts in U.S. State Electricity Policy, dated April 2019, p. 10, https://policyintegrity.org/files/publications/Valuing_Climate_Impacts.pdf.

198 J.C.J.M. van den Bergh and W J.W. Botzen, A lower bound to the social cost of CO2 emissions, dated March 2014.

199 Institute for Policy Integrity, New York University School of Law, Expert Consensus on the Economics of Climate Change, dated December 2015, https://policyintegrity.org/files/publications/ExpertConsensusReport.pdf.

200 *See*, Institute for Policy Integrity, New York University School of Law, Valuing pollution reductions: How to monetize greenhouse gas and local air pollutant reductions from Distributed Energy Resources, dated March 2018, pp. 26-27, https://policyintegrity.org/files/publications/Valuing_Pollution_Reductions.pdf. Compliance cost (e.g., RGGI price) is factored into the market price of a MWH produced by a fossil fuel generator. Failing to deduct compliance costs from the SCC benefit of a DER would mean the compliance cost – a fraction of SCC – is counted twice in the overall analysis of the economic benefit of DER.

Another approach to quantifying the economic benefits of avoided CO_2 emissions attributable to the deployment of clean and distributed energy resources, adopted in the most recent regional Avoided Energy Supply Components (AESC) study, attempts to circumvent the limitations of SCC estimations. The methodology used in the AESC study is based on the cost of avoiding a metric ton of emissions through deployment of New England offshore wind power, estimated at $75, and the cost of avoiding a ton of carbon dioxide emissions through carbon capture and geologic storage technology (in conjunction with a natural gas combined cycle generator), estimated at $110/metric ton.[201]

SCC in other State DER Valuations

Table 23 provides an overview of selected state evaluation studies of DERs reviewed for the Study. Three of the state evaluation studies adopted the IWG estimate as a basis for valuing the SCC. The other two set the value of avoided CO_2 emissions higher than the IWG value. The RGGI jurisdictions generally use RGGI compliance cost as the value of the avoided energy cost component, which is then deducted from the SCC to avoid double counting the same benefit, as discussed above.

Table 23: Social Cost of Carbon Benefit in Selected State Evaluations of DERs

State	SCC basis	Avoided energy cost component	Avoided societal cost component (2018 $)	Unit	Note
Arkansas	IWG	2015 IRP carbon cost	$43.48	$/MWh	Escalated rapidly at 5%/year
D.C.	IWG	RGGI	$38.14	$/MWh	Levelized at 3%, 2017-2040
Maine	IWG	RGGI	$21	$/MWh	Levelized at "environmental discount rate" (2015-2050?)
Nevada	–	Avoided compliance cost	0		
New York ('Order')	IWG	RGGI	?	$/MWh	
New York ('Staff')	Tier 1 REC	?	?		Tier 1 preferred because it is higher than IWG
Vermont	Set by PSB	RGGI	$97-102	$/metric ton	SCC based on 2013 AESC study

[201] Synapse Energy Economics, Inc., Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage, Avoided Energy Supply Components in New England: 2018 Report, dated October 24, 2018, pp. 140-144, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.

Given the well-publicized limitations of the IWG figure for SCC and the use of $133-143/metric ton in other SCC calculations, the Agencies applied a 3x multiplier to the valuation of avoided CO_2 emissions calculated in Section II of the Study to arrive at the results presented in the Summary Results in Section I.[202]

HEALTH AND SAFETY BENEFITS

The public health benefits of avoiding greenhouse gas emissions can be said to be incorporated in SCC. However, emerging broad assessments of the health ramifications of climate change outstrip the assessments on which prevailing estimates of SCC have been based.[203]

A comprehensive methodology for monetizing public health benefits from deployment of DERs is outlined in a recent report from New York University's Institute for Policy Integrity.[204] The main steps are:

1. Identify the generation displaced by a DER
2. Calculate emissions rates (kg/kWh) of the displaced resource
3. Calculate the damage per unit ($/kg) of avoided emissions
4. Monetize the value of avoided damage from displaced generation ($/kWh)
5. Subtract any damages from the DER itself to calculate net avoided damages

Growing literature supports state and federal efforts to bring health and safety benefits into these calculations. For example, an Oak Ridge National Laboratory study focusing on the health and safety benefits of federal home weatherization programs established monetized societal and household present values for a range of endpoints, including reductions in the incidence of: asthma, thermal stress, need for food assistance, carbon monoxide poisoning, home fires, and low birth weight.[205] Studies conducted for the Connecticut Energy Efficiency Board and for Massachusetts efficiency program administrators provide

---

202 A 3x multiplier was derived by comparing the Interagency Working Group's central estimate of $51/metric ton with the range of $133-143/metric ton.

203 *See*, the warning by leading public health organizations that climate change constitutes the "greatest public health challenge of the 21st century": U.S. call to action on climate, health, and equity: A policy action agenda, dated 2019, https://climatehealthaction.org/media/cta_docs/US_Call_to_Action.pdf. *See also*, the warning that "[l]eft unabated, climate change will define the health profile of current and future generations": Nick Watts, et al, The 2019 report of The Lancet Countdown on health and climate change: Ensuring that the health of a child born today is not defined by a changing climate, dated November 13, 2019, https://www.thelancet.com/journals/lancet/article/PIIS0140-6736(19)32596-6/fulltext.

204 Institute for Policy Integrity, New York University School of Law, Valuing pollution reductions: How to monetize greenhouse gas and local air pollutant reductions from Distributed Energy Resources, dated March 2018, https://policyintegrity.org/files/publications/Valuing_Pollution_Reductions.pdf.

205 Oak Ridge National Laboratory, Health and Household-Related Benefits Attributable to the Weatherization Assistance Program, dated September 2014, https://weatherization.ornl.gov/wp-content/uploads/pdf/WAPRetroEvalFinalReports/ORNL_TM-2014_345.pdf.

monetized values for reductions in similar sets of health and safety endpoints.[206,207] These and similar studies establish a reasonable expectation that states should make equivalent efforts to address health and safety benefits in the net cost of DERs. Indeed, the Study takes a similar approach in valuing avoided NO_x, SO_2, and $PM_{2.5}$ emissions as described in Section II.

In addition, although climate change affects health across the human population, "[u]rban populations, and especially socially and economically disadvantaged populations within urban areas, are likely to be especially vulnerable to the adverse effects of climate change."[208] Climate change places communities of color as well as low-income, immigrant, and limited English proficiency groups at heightened risk due to extreme heat events, extreme weather events such as hurricanes, degraded air quality, waterborne and vector-borne diseases, compromised food safety and security, and psychological stress.[209]

The Institute for Policy Integrity reviewed four standard tools for estimating the health impacts of specific avoided emissions:

- Air Pollution Emission Experiments and Policy analysis models (APEEP);
- BenMAP;
- Co-Benefits Risk Assessment (COBRA; mentioned above); and
- Estimating Air Pollution Social Impact Using Regression (EAPSIUR).[210]

Table 24 indicates the pollutants each of these models address.

---

[206] Applied Public Policy Research Institute for Study and Evaluation, Connecticut non-energy impacts literature review: R1709; final report, dated December 2018, https://www.energizect.com/sites/default/files/R1709_CT%20Non-Energy%20Impacts%20Literature%20Review_Final%20Report_Dec%202018.pdf.

[207] Three[3], Inc., and NMR Group, Inc., Massachusetts special and cross-cutting research area: Low-income single-family health- and safety-related non-energy impacts study, dated August 5, 2016, http://ma-eeac.org/wordpress/wp-content/uploads/Low-Income-Single-Family-Health-and-Safety-Related-NonEnergy-Impacts-Study.pdf.

[208] Janet L. Gamble, et al., U.S. Global Climate Change Research Program, Populations of Concern, dated 2016, p. 252, https://health2016.globalchange.gov/low/ClimateHealth2016_09_Populations_small.pdf.

[209] *Id.*, pp. 247-286.

[210] Institute for Policy Integrity, New York University School of Law, Valuing pollution reductions: How to monetize greenhouse gas and local air pollutant reductions from Distributed Energy Resources, dated March 2018, pp. 22-24, https://policyintegrity.org/files/publications/Valuing_Pollution_Reductions.pdf.

Table 24: Overview of Pollutants Addressed in State DER Valuation Studies and Common Tools to Calculate Health Effects of Emission Reductions

	Criteria pollutants							Other pollutants			
	Carbon monoxide	Lead	Nitrogen dioxide	Ozone	Partic-ulates	PM 2.5	Sulfur dioxide	Ammo-nia	Mercury	Volatile organics	Nitrogen oxides
States											
Arkansas						√	√				
D.C.											
Maine							√				√
Nevada						√	√		√		
New York ('Order')	"net avoided criteria air pollutants"										
New York ('Staff')							To be addres-sed				To be addres-sed
Vermont											
Tools											
APEEP						√	√ (and PM 10)	√		√	√
BenMAP				√		√					
COBRA						√	√	√		√	√
EAPSIUR						√	√	√			√

ADDITIONAL ENVIRONMENTAL BENEFITS

DERs have additional environmental benefits relating to land use that are difficult to quantify. The Agencies received written comments and public testimony from stakeholders regarding the environmental benefits of using existing building rooftops and parking lots rather than disturbing unused land. However, estimates of the lost value of land vary greatly, particularly if agricultural or habitat land is used to site a DER. According to the U.S. Department of Agricultural, the rental value for irrigated croplands in Arkansas was $132 per acre,[211] and 4 acres per GWh. Central-station solar photovoltaic plants with fixed arrays or single-axis tracking typically require 7.5 to 9.0 acres per MW-ac, or 3.3 to 4.4 acres per GWh per year. Thus, the land

211 *See*, U.S. Department of Agriculture, National Agricultural Statistics Service, Survey of 2017 Cash Rents, https://quickstats.nass.usda.gov/results/58B27A06-F574-315B-A854-9BF568F17652#7878272B-A9F3-3BC2-960D-5F03B7DF4826.

use value avoided by DERs sited on existing buildings was about $0.5 per MWh. The land use value avoided would be lower if the land has an alternative use of lower value than irrigated land for farming.[212] As the quantification of this DER value category yielded minimal quantifiable economic value, the lost value of land estimate was not included in the Summary Results in Section I. However, the Agencies recognize that this value may exist and DEEP is exploring how it could conduct this type of analysis in a future proceeding.

SUMMARY

The above review of the environmental and health benefits provided by DERs is based on the literature review conducted for the Study. The Agencies integrated the above findings into the analysis of the Study, primarily through the dispatch modeling performed and discussed in Section II. However, due to the well-publicized limitations of the IWG figure for SCC and the use of $133-143/metric ton in other SCC calculations, the Agencies multiplied the avoided CO_2 emissions benefits calculated in Section II, which used the three percent discount rate calculation for the SCC, by a factor of three to arrive at the Summary Results presented in Section I. of the Study.[213] The Agencies made no other alterations to the analysis presented in Section II. based on the Agencies' review of environmental and health benefits associated with DERs.

[212] Crossborder Energy, The Benefits and Costs of Net Metering Solar Distributed Generation on the System of Entergy Arkansas, Inc., dated September 15, 2017, p. 29, https://drive.google.com/file/d/0BzTHARzy2TINbHViTmRsM2VCQUU/view.

[213] A 3x multiplier was derived by comparing the Interagency Working Group's central estimate of $51/metric ton with the range of $133-143/metric ton.

IV. Conclusion

The Agencies note that as the Study focuses on the benefits that DERs provide to all electric ratepayers and to citizens of Connecticut, as a whole, that many of the benefits of DERs that accrue to individual customers and groups of customers are not quantified in the Study. Specifically, while the resilience benefits provided by DERs to individual customers and communities through emergency back-up power and microgrids are qualitatively discussed, they are not quantified in the Study. The Agencies endeavored to quantify as many DER value categories as possible, but ultimately were unable to value many of the hard-to-quantify benefits of DERs with specificity. Such value categories discussed in the Study that the Agencies were unable to quantify include: greater consumer choice, increased competition, technology synergy and adoption of other clean energy options, and increased customer engagement. However, in keeping with the best practices outlined in the NSPM, the Agencies qualitatively discussed all of the non-participant DER value categories of which they are aware in Section III.

Conversely, the Agencies also note that two important elements of cost-effectiveness testing, and cost-benefit analysis more generally, were omitted, as the two elements are outside of the scope of the Study: (1) program and technology costs; and (2) the assignment of costs and benefits to whom they accrue. Additionally, while not excluded from the Study, integration costs, specifically discussed as interconnection costs herein, were not included in the results presented above given that the interconnecting customer typically pays any such cost. Both technology and DER integration costs are significant for all of the DER technologies evaluated in the Study and are important factors for the Agencies to consider in any future DER cost-benefit analysis.

Lastly, the Agencies note that the results of the Study are helpful in providing an analytical estimate of the benefits of DERs to all ratepayers. As such, the results of the Study can inform, but are not sufficient, on their own to guide, policy direction for continuing or expanding policies and incentives supporting DERs. . Moreover, understanding the benefits of DERs is separate and distinct from understanding compensation levels needed to incentivize deployment, as with the cost-effectiveness testing for the C&LM Plan. One of the fundamental principles of establishing incentives paid for by all ratepayers is to set the incentive at a level no more than necessary to motivate performance to protect ratepayers from unreasonable costs and leave remaining ratepayers dollars available to incentivize even more deployment. This principle is fundamentally different from the valuation principles primarily discussed in the Study, and is an important distinction to frame the purpose of this study.[214]

Conversely, however, the Study results should not be interpreted as a cap on either the type of benefit categories, or the monetary value of such benefits, that DERs may ultimately deliver across the state. On the contrary, the Agencies have outlined and acknowledged the limitations the Study and of the currently

[214] *See*, John Shenot, The Regulatory Assistance Project, Quantifying and Maximizing the Value of Distributed Energy Resources, p. 17, https://www.raponline.org/wp-content/uploads/2020/05/rap_shenot_der_valuation_idp_orpuc_2020_may_08.pdf.

available data and certain methodologies. The Agencies pledge their resources to the continued exploration and, more importantly, the realization of the benefits of DERs.

NEXT STEPS

The Agencies have attempted to provide a fully transparent document and resource, including detailed explanations and data sets regarding all analytical and modeling assumptions, inputs, and outputs not only to aid in the discussion of the value of DERs in Connecticut, but also to allow stakeholders to validate and supplement the analysis contained in the Study.[215] The Agencies recognize that the analysis herein is by no means exhaustive, but rather a useful approximation of the benefits of DERs in Connecticut that will prove useful for future proceedings and cost-benefit analysis.

Both Agencies currently have work underway, or planned future work, relevant to the Study. DEEP continues to explore cost-effective pathways to a 100 percent zero carbon electric grid by 2040 through its Integrated Resource Plan and associated processes, of which DERs are an integral part. DEEP also continues to explore approaches to evaluating cost-effectiveness and to measuring and ensuring equitable distribution of benefits within the C&LM Program pursuant to Conn. Gen. Stat. Section 16-245m. The C&LM Plan will start developing the 2022-2024 program plan in the near future. The development process utilizes the information from the numerous evaluations of programs in the current portfolio and from other jurisdictions to inform future energy efficiency and demand response program designs. Additionally, PURA plans to take a more specific and detailed look at program costs, distribution system costs and benefits, and resilience benefits in Docket Nos. 17-12-03RE07, 17-12-03RE08, 17-12-03RE09, and 20-07-01, among others. One of the objectives of Docket Nos. 17-12-03RE07 and 17-12-03RE08 is to ensure that the distribution system benefits that DERs can provide are realized within the state in a consistent, transparent, and cost-effective manner. Further, Docket Nos. 17-12-03RE09 and 20-07-01 will review the state's current DER and renewable energy programs and will look to utilize lessons learned from those programs, and the insights provided by this study, to develop new programs and reporting metrics to ensure that the state is maximizing the value that all DERs provide.

Most importantly, the Agencies are ***firmly committed to the cost-effective, timely, and continual development and deployment of DERs in Connecticut***. This study and the planned work outlined above is just a small part of that commitment. Both Agencies look forward to continuing to engage with stakeholders on the topics addressed in the Study and on how best to promote and deploy DERs in the state.

---

215 See Appendix A. and B. for the Aurora dispatch modeling assumptions and inputs used in the Study. See Appendix B.I. through B.VI. for the dispatch modeling outputs for each Use Case.

Appendix A. Factor Inputs for Reference Case Dispatch Simulation Model

DEFINITION OF THE REFERENCE CASE

The Study utilized an electric system simulation model to derive certain quantitative value categories that are oriented around the wholesale electricity market. The Reference Case prepared in the simulation model represents a "business-as-usual" wholesale market forecast without the addition of new (*i.e.* incremental) distributed energy resources (DER) over the study period.[1] It serves as the baseline condition against which incremental costs, benefits, and environmental impacts of various DERs can be measured. The Reference Case is based on the Independent System Operator New England Inc. (ISO-NE) market rules and published forecasts, resource additions and retirements, and state policies that are currently "known and knowable."

ELECTRIC SIMULATION MODELING

The electric simulation modeling used Aurora, a chronological dispatch simulation model licensed from Energy Exemplar, to forecast power market outcomes, including energy prices, emissions from electricity generation, and natural gas demand from electric generation.[2] The forecast period was from 2021 through 2045 to cover the expected lifetime of the different DER Use Cases. The Reference Case was run at the zonal level using Aurora's Long-Term Capacity Expansion modeling capability. Aurora simulated all hours in each forecast year.

Study Region

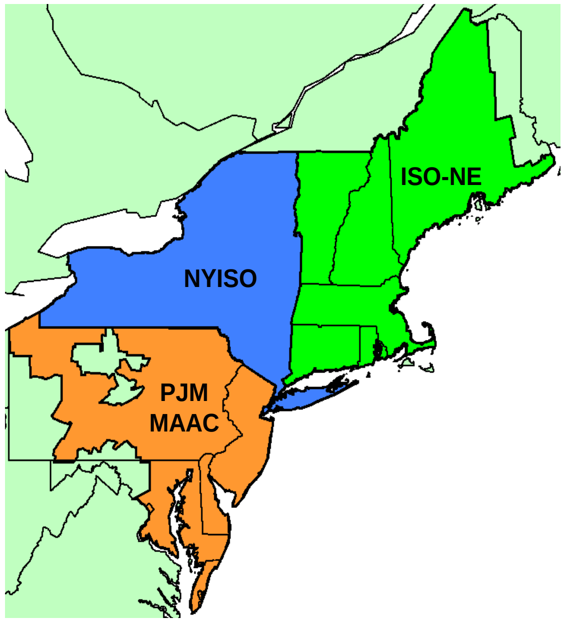
The study region covered ISO-NE, New York Independent System Operator (NYISO), and the Mid-Atlantic Area Council (MAAC) portion of PJM Interconnection LLC (PJM).[3] The three regional transmission organizations (RTOs) were further divided into zones to capture key transmission constraints. ISO-NE was divided into the 13 sub-areas identified in the Regional System Plan (RSP). NYISO was divided into seven load zones (A through K, with some aggregation upstate). The MAAC portion of PJM was divided into three Locational Deliverability Areas: EMAAC, SWMAAC, and Rest of MAAC.

[1] The forecast of DERs for Connecticut included in ISO-NE's Forecast Report of Capacity, Energy, Loads, and Transmission (CELT) was not included in the Reference Case. ISO-NE's forecast of energy efficiency for Connecticut was included and was extrapolated through 2045.

[2] A previous draft of this Appendix listed capacity prices as a power market output that would be calculated for the Study. However, due to the complexity of and uncertainty in predicting capacity prices, the Agencies, in deliberation with their consultants, decided to instead provide historical capacity prices, as discussed in detail below.

[3] Modeling only the MAAC portion of PJM reduces run time while still capturing the market dynamics associated with the PJM and NYISO transmission interchange.

Figure 1: Study Region



Boundary flows to/from Quebec, New Brunswick, and Ontario Independent Electricity System Operator (IESO) were modeled based on an average weekly profile for each month using three years of historical flow data (168 hours by 12 months). Historical averages from 2017 through 2019 were used in the Study. Imports into New York from Ontario were reduced to consider the impending refurbishment schedule of IESO's nuclear units.

Transmission Transfer Limits

Inter-zonal transmission transfer limits were defined using publicly available data sources. The primary source for transfer limits within ISO-NE was the FCM Capacity Commitment Period Tie Benefits Study Assumptions, augmented by several smaller adjustments per other sources, as noted below.[4]

[4] Quan Chen, ISO-NE, 2023-2024 Capacity Commitment Period Tie Benefits Study Assumptions, dated May 30, 2019, https://www.iso-ne.com/static-assets/documents/2019/05/a62_fca14_tie_benefits_assumpts_05302019.pdf.

Figure 2: ISO-NE Transmission System Representation[5]

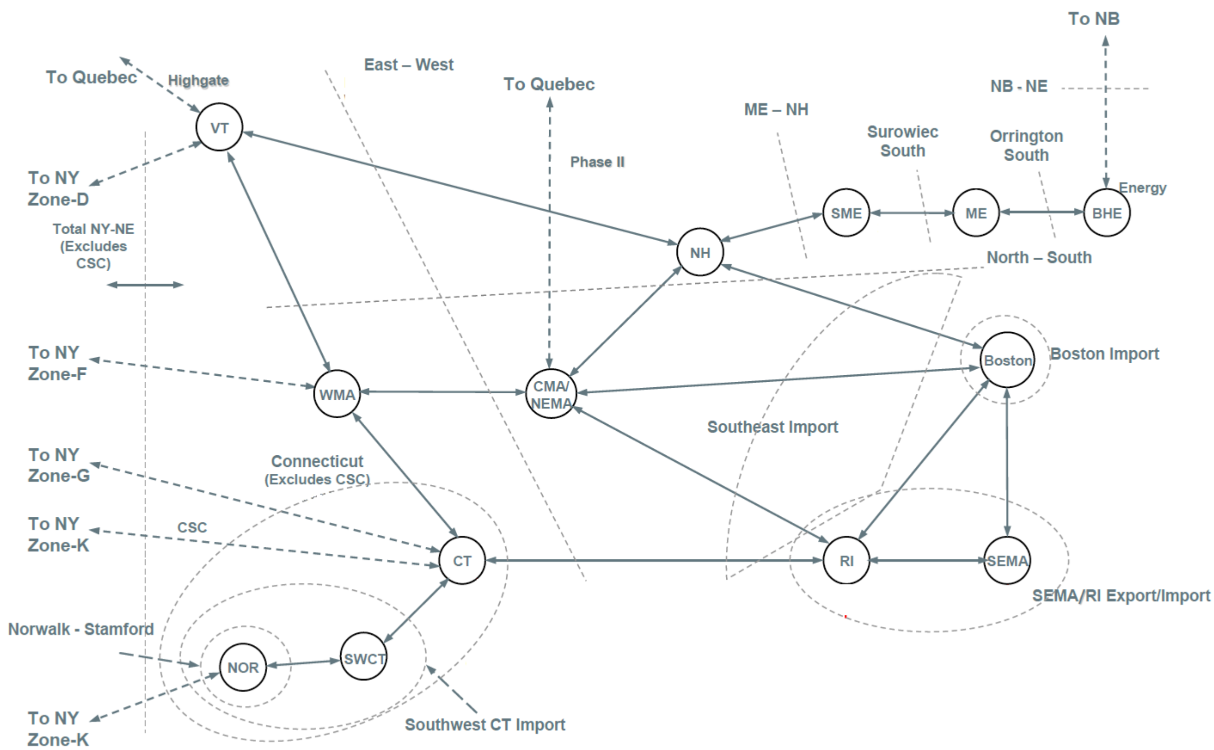


Table 1: ISO-NE Internal Interface Transfer Capabilities (MW)[6]

Interface	2020	2021	2022	2023	2024+
Orrington South	**1325**	**1325**	**1325**	**1325**	**1325**
Surowiec South	**1500**	**1500**	**1500**	**2500**[7]	**2500**
Maine-New Hampshire	**1900**	**1900**	**1900**	**1900**	**1900**
North-South	**2725**	**2725**	**2725**	**2725**	**2725**
East-West	**3500**	**3500**	**3500**	**3500**	**3500**
Boston Import	**5400**	**5700**	**5700**	**5700**	**5150**[8]
SEMA/RI Export	**3400**	**3400**	**3400**	**3400**	**3400**

---

[5] *Id.*

[6] Import interfaces are modeled at (N-1) capability.

[7] Surowiec South transfer limit increased due to inclusion of NECEC and associated upgrades per ISO-NE economic study: Patrick Boughan, ISO-NE, NESCOE 2019 Economic Study – 8,000 MW Offshore Wind Results, dated February 20, 2020, https://www.iso-ne.com/static-assets/documents/2020/02/a6_nescoe_2019_Econ_8000.pdf.

[8] SENE and Boston Import capabilities were updated due to Mystic 8/9 retirement for FCA 15, per ISO-NE materials. *See,* Al McBride, ISO-NE, Updated Southeast New England and Boston Import Transfer Capabilities: Capacity Commitment Period 2024-25, dated February 20, 2020, https://www.iso-ne.com/static-assets/documents/2020/02/a5_bos_imp_trans_update.pdf.

SEMA/RI Import	**1280**	**1280**	**1280**	**1800**	**1800**
SENE Import	**5400**	**5700**	**5700**	**5700**	**5150**[9]
Connecticut Import	**3400**	**3400**	**3400**	**3400**	**3400**
SWCT Import	**2800**	**2800**	**2800**	**2800**	**2800**

Defining the transfer capabilities between ISO-NE and NYISO required review and reconciliation of each RTOs' planning documents. Transfer capabilities between ISO-NE and NYISO, summarized in Table 2, were derived from the ISO-NE FCM Tie Benefits Study and NYISO's Reliability Needs Assessment.

Table 2: Transfer Capability Assumptions, ISO-NE and NYISO (MW)

Interface	2020	2021	2022	2023	2024+
NE-NY[10]	**1400**	**1400**	**1400**	**1400**	**1400**
NY-NE[11]	**1400**	**1400**	**1400**	**1400**	**1400**
F to WMA	**800**	**800**	**800**	**800**	**800**
WMA to F	**800**	**800**	**800**	**800**	**800**
G to CT-C	**800**	**800**	**800**	**800**	**800**
CT-C to G	**600**	**600**	**600**	**600**	**600**
Cross-Sound Cable	**330**	**330**	**330**	**330**	**330**
NOR to K[12]	**260**	**260**	**260**	**260**	**260**
K to NOR	**414**	**414**	**414**	**414**	**414**

NYISO transfer limits were primarily sourced from the 2018 Reliability Needs Assessment and adjusted to account for the AC Public Policy Transmission Project that the NYISO Board of Directors approved in April 2019, which will be in service for the full 2024 calendar year.[13] Several NYISO transfer limits were dynamically set based on unit availability or generation.

Interface limits for PJM were informed by Planning Period Parameters for the Base Residual Auction, which include Capacity Emergency Transfer Limits for many delivery areas.[14] In cases where link limits in PJM

[9] *Id.*
[10] Interface does not include Cross-Sound Cable.
[11] *Id.*
[12] Dynamic export limit per availability of Norwalk units, *See*, NYISO, 2018 Reliability Needs Assessment, dated October 16, 2018, https://www.nyiso.com/documents/20142/2248793/2018-Reliability-Needs-Assessment.pdf.
[13] NYISO, AC Public Policy Transmission Plan Report, dated April 8, 2019, https://www.nyiso.com/documents/20142/5990605/AC-Transmission-Public-Policy-Transmission-Plan-2019-04-08.pdf/0f5c4a04-79f4-5289-8d78-32c4197bcdf2.
[14] *See*, PJM, Capacity Market (RPM), https://pjm.com/markets-and-operations/rpm.aspx.

were not available, the analysis relied on the default settings provided by Energy Exemplar. Energy Exemplar performs a nodal power flow simulation that informs the zonal transmission limits.

DEMAND FORECAST

RTO planning documents, such as the 2019 ISO-NE's Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report), NYISO's 2019 Load and Capacity Data report (Gold Book), and PJM's 2020 Load Forecast Report, were the basis for peak and annual energy forecasts used in the Reference Case. The ISO-NE and PJM forecasts do not cover the full study period. Beyond the published RTO forecast, gross energy for load and summer and winter peaks were assumed to follow exponential growth curves based on each respective zone's combined annual growth rate over each respective RTOs' forecast period.

Gross demand forecasts in the RTO planning documents include load that is served by BTM solar. For modeling purposes, BTM solar was deducted from the gross load forecast across the study region on an hourly basis in order to reflect the changes to hourly load shape that solar creates, since solar generation does not track demand. Beyond the final year of the RTO planning document, BTM solar was extrapolated at a constant MW and MWh growth rate using the last forecast years' expansion rate of the relevant planning document.

Connecticut, however, was treated differently in the Reference Case in order to create a "but for" test to gauge the impact of incremental DERs. Specifically, the Study aims to inform DER policy and program design moving forward; thus, a "but for" test to understand the value of any and all incremental DERs over the forecast period is the most appropriate approach. Thus, incremental BTM solar in Connecticut that is forecasted in the 2019 CELT was not deducted from gross load in the Reference Case.

Gross demand forecasts in RTO planning documents also include energy efficiency (EE) and passive demand response (PDR), which offset demand, so these components are also netted from gross demand in the model. Beyond the RTO planning forecast, EE and PDR were extrapolated using a constant growth rate based on the last years of the relevant RTO forecast. This approach was also taken for Connecticut as the Study does not seek to evaluate the value of the state's current EE policies and programs, but rather to evaluate the value of EE incremental to current EE policies and programs, specifically the Conservation and Load Management Plan.

Demand Projections for Increased Electrification

The most recent Gold Book incorporates the NYISO's outlook for increased electrification of the transportation and building sectors over the forecast period; PJM's forecast also reflects increased deployment of electric vehicles (EV). ISO-NE will include transportation electrification in the 2020 CELT Report; however, the 2020 CELT was not released when the modeling for the Study commenced. Transportation electrification in ISO-NE therefore was included as an adjustment to the 2019 CELT Report forecast using the approach proposed by ISO-NE's Load Forecast Committee.[15] As a starting point, data on the stocks of battery electric vehicles (BEVs) and plug-in hybrid EVs (PHEVs) in 2018 were obtained from the Alliance of Automobile Manufacturers 2018 light-duty vehicle (LDV) registrations.[16] Projected annual sales of BEVs and PHEVs for years 2019 through 2029 reflect the U.S. Energy Information Administration's (EIA) 2019 Annual Energy Outlook (AEO) reference case regional forecast for New England.[17] For those years, the annual forecast of light-duty electric vehicles (LDEVs) for the New England region was allocated to each state based on its 2018 share of LDEVs relative to all New England states, as shown in Table 3.

Table 3: Electric Vehicles 2018 Stocks and Regional Share by State

State	Total LDEV Registrations (2018)	State Share of New England Region
CT	9,799	23.7%
MA	21,258	51.4%
ME	2,529	6.1%
NH	3,099	7.5%
RI	1,738	4.2%
VT	2,926	7.1%
Total	**41,349**	**100%**

Beyond 2029, the AEO annual LDEV sales forecast represents a more conservative long-term outlook of LDEV sales penetration rates than many other studies, including the ongoing Transportation Climate Initiative (TCI) reference case.[18] Therefore, instead of applying the AEO sales forecast beyond 2029, the annual LDEV sales penetration rate in 2045 for each state was assumed to be 15 percent greater than the 2029 LDEV sales penetration rate. Interim years were interpolated. Table 4 provides the percentage of annual LDV sales forecasted to be EVs in 2020 and 2045.

Table 4: LDEV New Sales Penetration Rate

State	2020	2045
CT	**5%**	**24%**
MA	**5%**	**25%**
ME	**3%**	**21%**
NH	**2%**	**21%**
RI	**3%**	**21%**
VT	**6%**	**26%**

---

[15] ISO-NE, Final Draft 2020 Transportation Electrification Forecast, dated February 18, 2020, https://www.iso-ne.com/static-assets/documents/2020/02/final-draft-2020-transpelectr.pdf.

[16] Fact sheets for each New England state downloaded on October 31, 2019 from the Alliance of Automobile Manufacturers (Auto Alliance), *See*, Auto Alliance, Every State is an Auto State, https://autoalliance.org/in-your-state/.

[17] Annual forecasted BEVs is the sum of all forecasted 100-mile, 200-mile, and 300-mile electric cars and light trucks and PHEVs is the sum of Plug-in 10 and 40 Gasoline Hybrid cars and light duty trucks.

[18] Data provided by a TCI consultant supports a forecasted 2045 energy demand of 14,144 GWh for the New England footprint, whereas following the methodology used in the CELT Report forecast through 2045 implies only 3,320 GWh of energy demand in 2045.

EVs were assumed to have an average useful life of 11 years.[19] For PHEV stock as of 2018, the vehicles were phased out at 20% of the 2018 PHEV stock per year from 2026 to 2030. For BEV stock as of 2018, the vehicles were phased out at 50% in 2028 and 50% in 2029.

EV Daily and Annual Demand

The average daily charging energy by month for BEVs and PHEVs is shown in Table 5. These values were calculated using data from the ISO-NE Transportation Electrification Forecast and from Argonne National Laboratory (ANL).[20,21]

Table 5: ISO-NE Average Daily Charging Energy

Month	Average Daily BEV Charging Energy (kWh)	Average Daily PHEV[22] Charging Energy (kWh)
Jan	**12.1**	**8.6**
Feb	**11.4**	**8.1**
Mar	**11.5**	**8.2**
Apr	**10.8**	**7.7**
May	**10.1**	**7.2**
Jun	**9.2**	**6.6**
Jul	**8.4**	**6.0**
Aug	**9.0**	**6.4**
Sep	**9.4**	**6.7**
Oct	**10.9**	**7.8**
Nov	**11.3**	**8.1**
Dec	**11.2**	**8.0**
Annual	*10.4*	*7.5*

In 2019, EV penetration in New England accounted for just one percent of the total LDV stock and 367 GWh of annual demand. EV penetration in New England is projected to reach 14% of total LDV stock and approximately 5,858 GWh of annual demand in 2045. EV penetration in Connecticut is projected to reach 15% of the total LDV stock and accounts for about 1320 GWh of annual demand in 2045.

EV Charging Load Profiles

Fixed hourly EV charging profiles that reflect aggregated charging behavior in New England were developed. These profiles differentiate the daily charging regime by month and weekday versus

[19] The 2018 state fact sheets from the Alliance of Automobile Manufacturers that contained the LDV registrations also provide the average life of an LDV in that state. Average LDV life in New England States was about 11 years.

[20] ISO-NE, Final Draft 2020 Transportation Electrification Forecast, dated February 18, 2020, p. 14, https://www.iso-ne.com/static-assets/documents/2020/02/final-draft-2020-transpelectr.pdf.

[21] *See,* Argonne National Laboratory, Impacts of Electrification of Light-Duty Vehicles in the United States, 2010-2017, dated January 2018, https://publications.anl.gov/anlpubs/2018/01/141595.pdf.

[22] The factor 0.714 is the ratio of the PHEV to BEV charging demand from the Argonne National Laboratory study.

weekend/holiday, thereby accounting for seasonality associated with expected EV charging patterns. Both weekday and weekend charging profiles reflect aggregated residential (78%) and non-residential (22%) charging demand. The modeled profiles were adapted from data presented by ISO-NE in two Load Forecasting Committee meetings.[23]

Demand Projections for Building Sector Electrification

The 2019 ISO-NE CELT Report forecast was also adjusted to account for conversions to efficient air source heat pump (ASHP) electric hearing across the region. The number of occupied housing units by space heating fuel type and state was obtained from the U.S. Census Bureau American Community Survey (ACS) for 2013-2017.[24] Current ASHP installations by state were estimated from a report by the Vermont Energy Investment Corporation (VEIC).[25] Between 2019 and 2045, the penetration rate was assumed to follow an "s-curve", beginning slowly, accelerating from 2029 through 2040, then tapering off in the last five years as the market becomes saturated. By 2045, the total conversions across New England were projected to be approximately 1.3 million. Estimated conversion penetration from existing space heating fuels by 2045 is shown in Table 6. Growth in the housing stock through 2045 was not forecasted since it is not a major factor for the low-growth New England region.

Table 6: Shares of Existing Space Heating Fuels Converted to ASHP by 2045

Heating Fuel	Conversion Percentage
Natural Gas	20%
CNG, LPG	27%
Electric Resistance	34%
Oil	27%
Wood	0%
Other	0%

Energy use per installation was estimated based on a 2019 New York State Energy Research and Development Authority (NYSERDA) study that reported results for upstate and downstate New York

[23] Weekday profiles for each month were adapted from the curves presented here: Jon Black, ISO-NE, Draft 2020 Transportation Electrification Forecast, dated December 20, 2019, p. 13, https://www.iso-ne.com/static-assets/documents/2019/12/draft_2020_transpElectr_fx.pdf. Weekend profiles for each month were adapted from the 50th percentile of the box plots presented here: Jon Black, ISO-NE, Update on the 2020 Transportation Electrification Forecast, dated November 18, 2019, https://www.iso-ne.com/static-assets/documents/2019/11/p2_transp_elect_fx_update.pdf. As proposed in the December 20 presentation, monthly energy demand reflects a 6 percent gross up to account for transmission and distribution losses.

[24] U.S. Census Bureau, Tenure by House Heating Fuel, 2013-2017 American Community Survey 5-Year Estimates, https://data.census.gov/cedsci/table?g=0400000US09,23,25,33,44,50&tid=ACSDT5Y2017.B25117&q=B25117.

[25] Vermont Energy Investment Corporation, Driving the Heat Pump Market: Lessons learned from the Northeast, dated February 20, 2018, p. 11, Table 2, https://www.veic.org/Media/default/documents/resources/reports/veic-heat-pumps-in-the-northeast.pdf.

regions.[26] The downstate New York estimates for space heating and cooling were used as proxies for the southern New England states (Connecticut, Massachusetts, Rhode Island). Upstate New York estimates for space heating and cooling were used as proxies for the northern New England states (Maine, New Hampshire, Vermont). The simple average of the values for electricity use for centralized ASHP units in existing buildings and mini-split ASHP units for both existing buildings and new construction was calculated to estimate the heating energy use per ASHP unit for the two New England climate zones.[27]

The increase in electric demand when ASHPs replace non-electric heating fuels was only included during the heating season (October-April). Based on the NYSERDA study, ASHPs do not provide a substantial energy savings when they replace conventional air conditioners.[28] Energy savings from ASHPs replacing resistance electric heating were included in the EE forecast.

Load Shapes

As a starting point, base load shapes for each zone were provided by Energy Exemplar. These load shapes were developed by reviewing historic load data from each RTO and calculating a scalar value, which was then applied to the peak and annual energy forecasts for each value. The load profiles considered three years of historic load data. The base load shapes were applied to ASHP demand as well as gross demand net of EE. The base load shapes were then adjusted to account for the incremental load produced by EV forecasts. Representative hourly load profiles for a sample week in each month in 2030 are illustrated in Figure 3 and Figure 4.

---

[26] New York State Energy Research and Development Authority (NYSERDA), New Efficiency: New York: Analysis of Residential Heat Pump Potential and Economics, Final Report, dated ated January 2019, Table 6-2, https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf.

[27] Based on the NYSERDA study, half of the installations were assumed to be centralized ASHP systems, and half were assumed to be mini-split systems. All of the centralized systems were assumed to be installed in existing buildings. Mini-split systems were assumed to be installed half in existing building and half in new construction.

[28] NYSERDA, New Efficiency: New York: Analysis of Residential Heat Pump Potential and Economics, Final Report, dated ated January 2019, p. 25, https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf.

Figure 3: Hourly Load Profiles for Sample Weeks, Winter Months, 2030

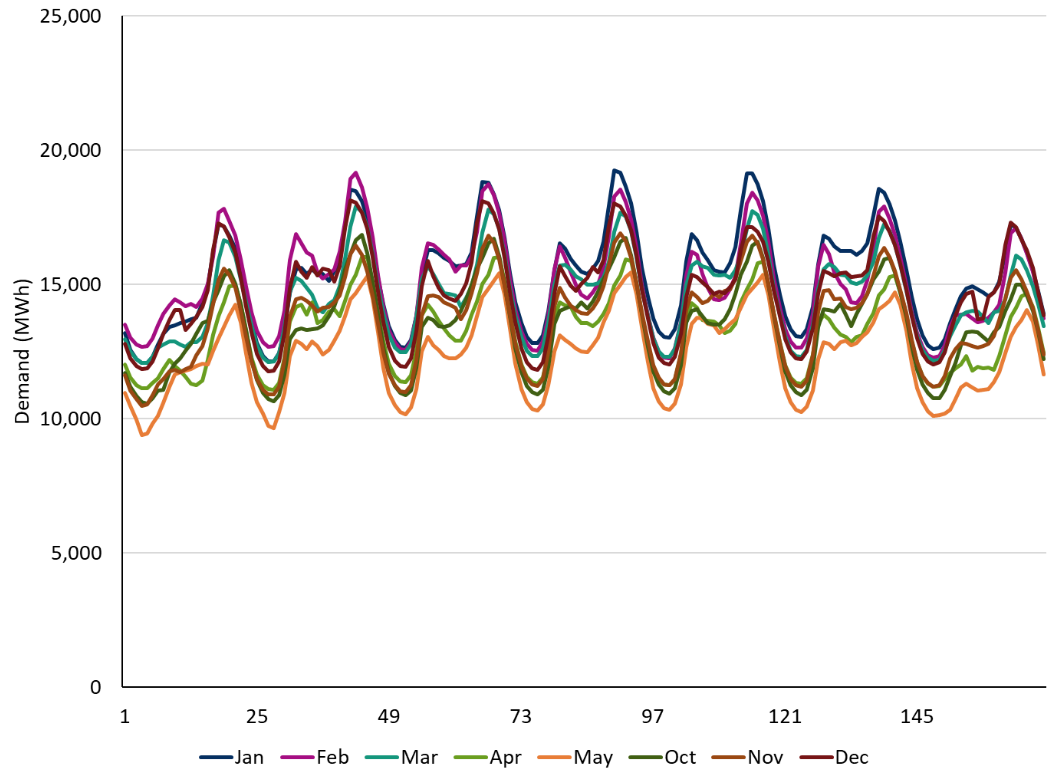
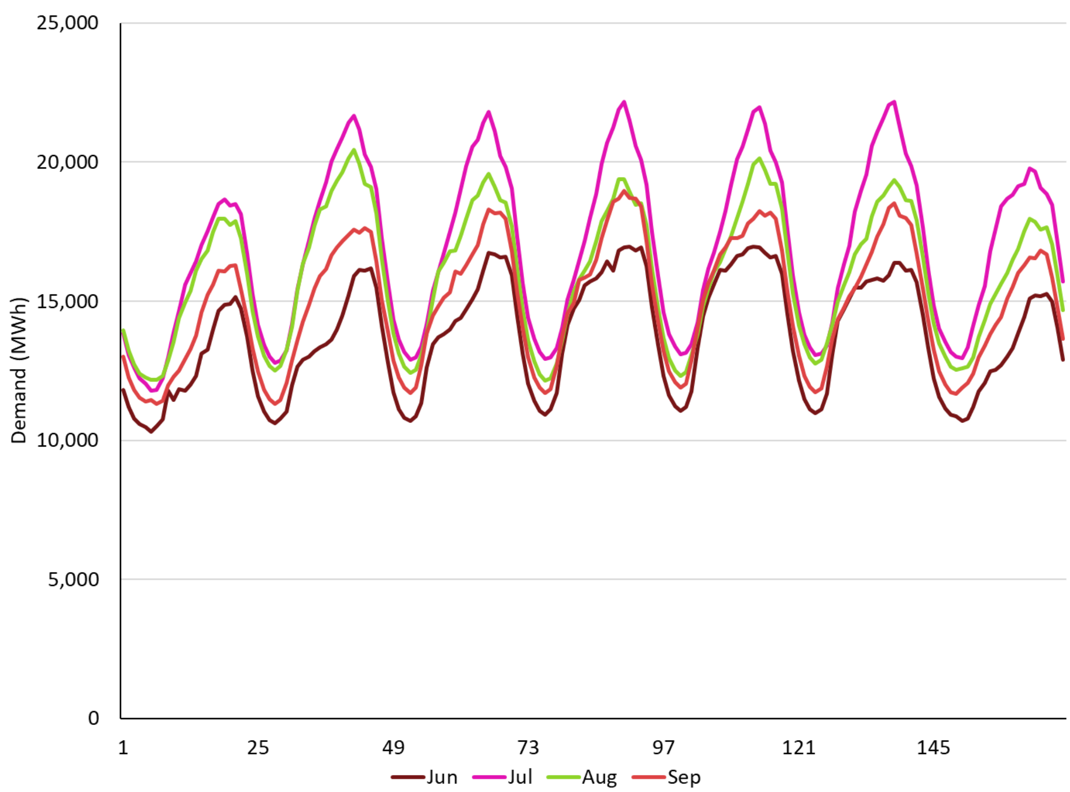


Figure 4: Hourly Load Profiles for Sample Weeks, Summer Months, 2030



RENEWABLE ENERGY PROFILES

Land-based wind energy profiles are based on Energy Exemplar's proprietary dataset, which normalizes profiles from the NREL Wind Integration National Dataset (WIND) Toolkit to reflect varying capacity factors, as existing wind sites often have different effective capacity factors than the NREL WIND Toolkit.[29] Offshore wind (OSW) profiles are set based on the WIND Toolkit database using the 2009 wind profile and the Toolkit IDs shown in Table 7.

Table 7: Wind Toolkit Data Sampled[30]

State	Lease/Call Area	Wind Toolkit IDs
MA	**500**	**96007,91897**
MA	**501**	**96526**
MA	**520**	**93857**
MA	**521**	**93348**
MA	**522**	**92673**
RI	**486**	**95466,95741,94113,93114**
RI	**487**	**91897**
DE	**482**	**54689,55311**
MD	**489**	**52657**
MD	**490**	**51704**
NJ	**498**	**61555,59139,61550**
NJ	**499**	**68746,64985,63457**
NY	**512**	**77536,77535,77779**
NY	**Fairways North**	**85703,90623**
NY	**Fairways South**	**80991,80083**
NY	**Hudson North**	**77536**

Solar PV energy profiles were set by running NREL's System Advisor Model (SAM) using Typical Month Year 3 (TMY3) data from the National Solar Radiation Data Base.[31] The TMY3 data is imported into SAM as the weather input and then SAM simulations are run with selected inputs for rooftop photovoltaic (RPV) and utility photovoltaic (UPV) systems to calculate solar energy profiles. Connecticut Green Bank data[32] for

---

[29] *See*, National Renewable Energy Laboratory, Wind Integration National Dataset Toolkit, https://www.nrel.gov/grid/wind-toolkit.html.

[30] Some Wind Toolkit IDs are used for multiple lease areas if there are no toolkit points located in a lease area.

[31] *See*, National Renewable Energy Laboratory, National Solar Radiation Data Base, https://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/by_state_and_city.html.

[32] *See*, Docket No. 19-06-29, Interrogatory Responses, dated April 2 and 3, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=19-06-29.

production from rooftop solar systems installed in 2017 and 2018 were used to adjust capacity factors to reflect Connecticut BTM solar in the Reference Case and in designing the DER Technology Use Cases, as outlined in Appendix B.

Table 8: SAM Modeling Parameters

Interface	UPV Fixed	UPV Tracking	RPV
Module Type	**Premium**	**Premium**	**Standard**
DC to AC Ratio	**1.31**	**1.25**	**1.1**
Inverter Efficiency	**96%**	**96%**	**96%**
Array Type	**Fixed Open Rack**	**1 Axis Tracking**	**Fixed Roof Mount**
Tilt (degrees)	**20**	**0**	**20**
Azimuth	**180**	**180**	**180**
Ground Coverage Ratio	**0.4**	**0.4**	**N/A**
Total Losses	**14%**	**14%**	**14%**

FUEL PRICES FORECAST

Fuel prices, as delivered to generators, are forecasted for natural gas, oil products, and coal. Nuclear generators are price takers and have virtually no dispatch flexibility. Therefore, no nuclear fuel price forecast is required as plants are assumed to run fully loaded and the cost of nuclear fuel is never at the margin.[33]

Natural Gas Price Forecast

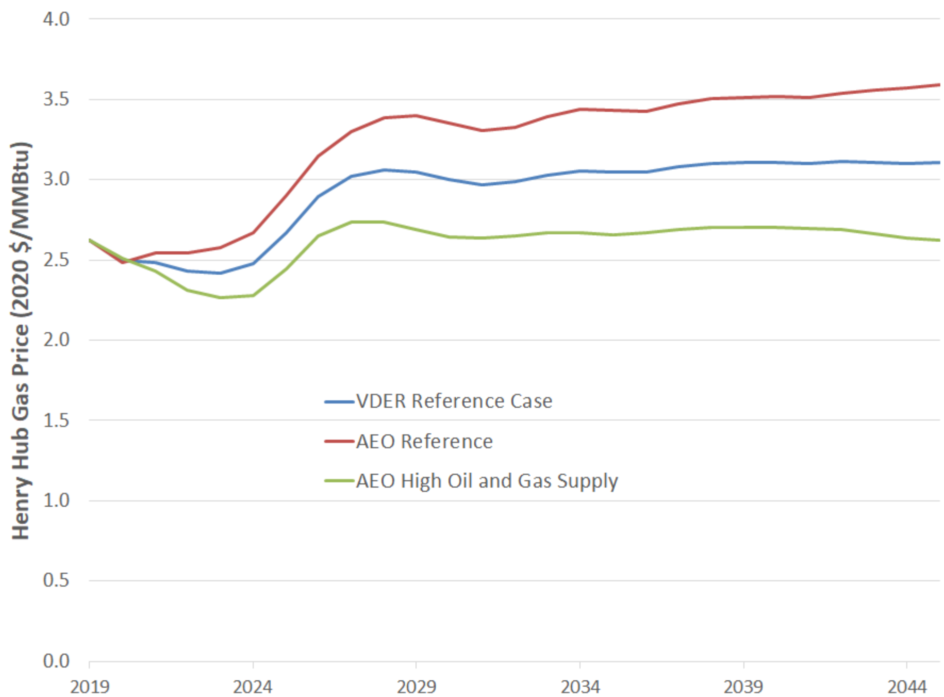
The forecast of delivered natural gas prices was based on the Henry Hub commodity price projection from EIA's 2020 AEO.[34] Historically, the AEO Reference Case has overestimated the trajectory of natural gas prices. A simple average of the AEO Reference Case and the AEO High Oil and Gas Resource and Technology Case was therefore used, as illustrated in Figure 5. Monthly shaping of natural gas prices into-the-pipe in Louisiana was applied to the annual prices over the study period based on the average monthly profile of historic Henry Hub prices observed over the last ten years.

---

33 Aurora schedules refueling outages per 18-month or 24-month cycles per a review of Nuclear Regulatory Commission operating data.

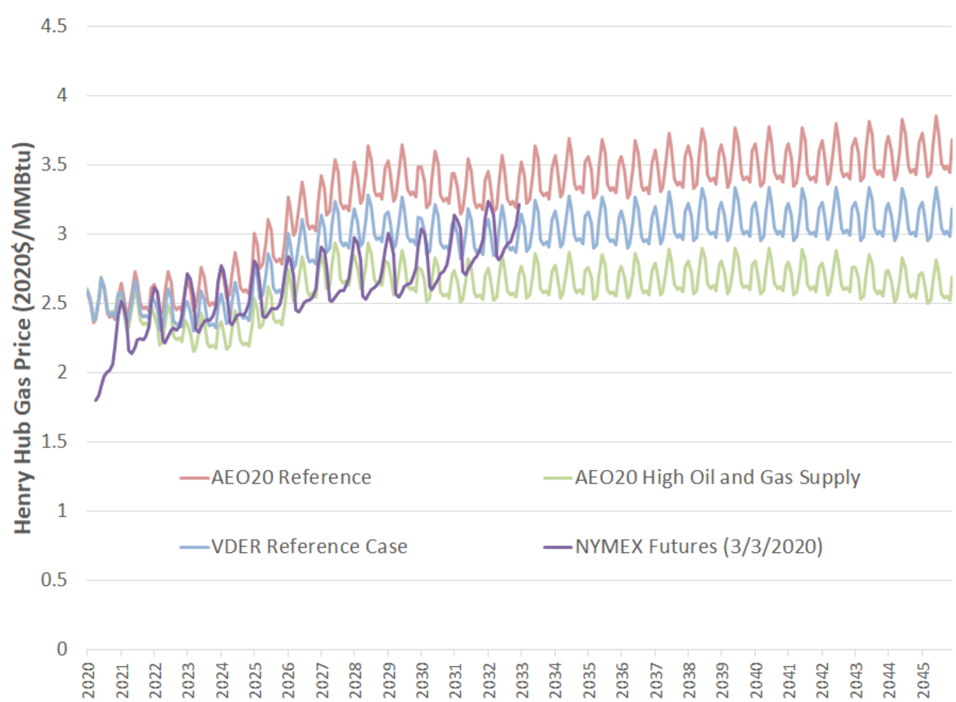
34 *See*, U.S. Energy Information Administration, Annual Energy Outlook 2020 with projections to 2050, dated January 2020, p. 48, https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Full%20Report.pdf.

Figure 5: Annual Average Natural Gas Commodity Price Projections



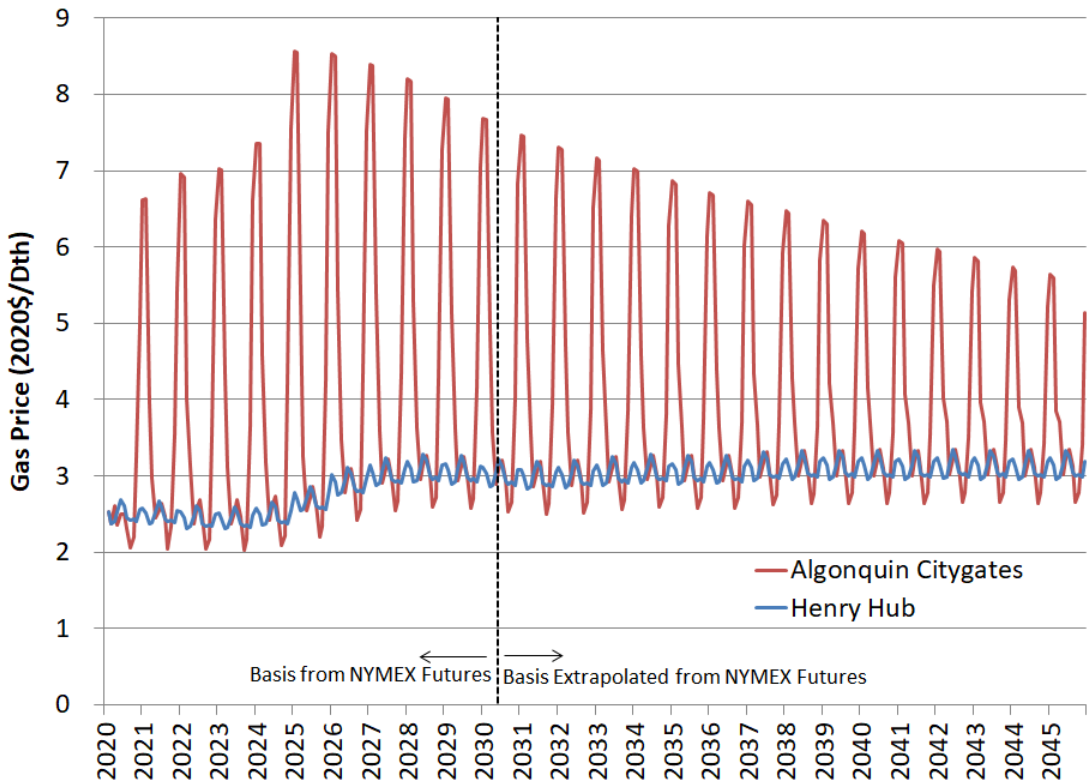
Use of the average of the AEO Reference and High Oil and Gas Resource cases was supported by a comparison to recent Henry Hub futures prices. Figure 6 overlays the March 3, 2020 New York Mercantile Exchange (NYMEX) settle prices against the 2020 AEO Henry Hub forecasts after monthly shaping has been applied. The AEO Reference case is consistently higher than the market perspective represented by NYMEX.

Figure 6: Natural Gas Commodity Price Projection Comparisons



Regional basis and the resultant delivered natural gas prices were based on the latest available OTC Global Holdings natural gas forward prices. This forward pricing data is available for a ten-year forecast period. The Algonquin Citygates basis forward price for the peak winter months increases from 2020 through 2024, and then declines over the remainder of the available price string. The forecast to 2045 was therefore extrapolated based on the annual percentage change for each month from 2024 through 2029. Figure 7 shows the resultant delivered Algonquin Citygates price and the monthly Henry Hub commodity price over the forecast period.

Figure 7: Monthly Average Natural Gas Price Projections for Henry Hub and Algonquin Citygates[35]



Other Fuel Price Forecasts

Delivered oil products prices were forecasted based on the 2020 AEO, consistent with the Henry Hub forecast. Coal prices were forecasted using the 2020 AEO prices for delivered coal to electric generators as a commodity price.[36] These prices were then adjusted on a unit and state-level to reflect local price adders based on basin sourcing and transportation costs. These adders were developed by Energy Exemplar and are primarily based on a review of EIA-923 fuel receipts data.

---

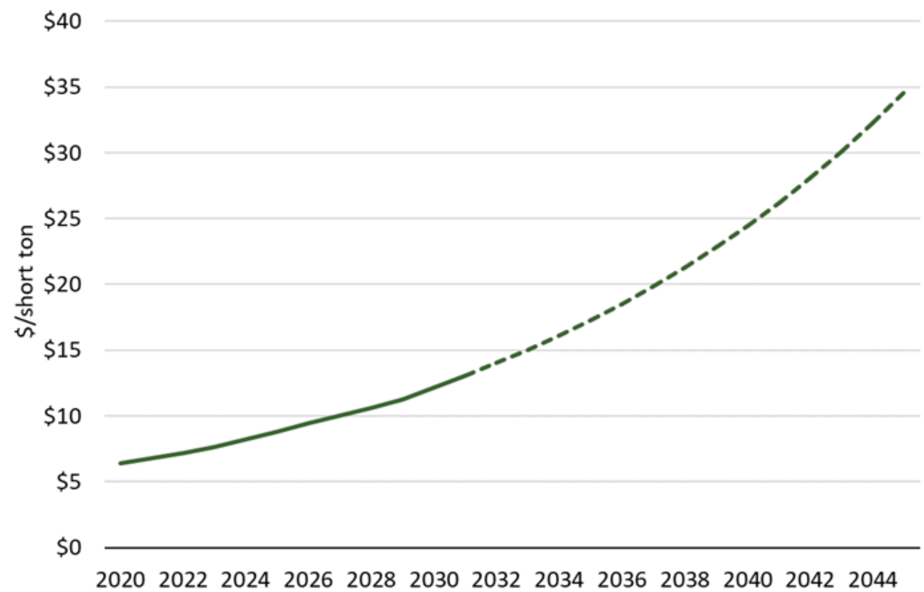
[35] Algonquin CItygates projection is based on forward prices as of December 4, 2019.

[36] *See*, U.S. Energy Information Administration, 2020 Annual Energy Outlook, Table 15. Coal Supply, Disposition, and Prices, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=15-AEO2020&cases=ref2020&sourcekey=0

CARBON ALLOWANCE PRICE

The CO_2 allowance price forecast relied on the Regional Greenhouse Gas Initiative (RGGI) Model Rule Policy Scenario forecast that was prepared on behalf of the 2017 RGGI Program Review.[37] It was assumed that RGGI prices will continue the trend in the most recent program review modeling results. Prices beyond 2031 were extrapolated by applying the growth rate observed in the program review prices. At the time the RGGI Model Rule forecast was prepared, New Jersey was not a RGGI participating state. New Jersey rejoined RGGI as of January 1, 2020.[38] The cap was assumed to increase accordingly, and therefore has no direct impact on the allowance prices. Pursuant to the Clean Economy Act, Virginia is expected to rejoin as a RGGI participating in 2021. Consistent with Governor Wolf's Executive Order, Pennsylvania is investigating joining RGGI as a participating state.

Figure 8: CO2 Allowance Price Forecast (nominal $)



NYISO has developed a proposal for pricing the Social Cost of Carbon into its energy markets, with accompanying tariff language drafted. However, a stakeholder vote has been delayed.[39] The outcome of any vote is far from certain and the proposal faces further hurdles during the FERC filing process. Therefore, the model did not incorporate a NYISO-specific carbon cost.

37 *See*, RGGI, Model Rule, dated December 14, 2018, https://www.rggi.org/sites/default/files/Uploads/Design-Archive/Model-Rule/2017-Program-Review-Update/2017_Model_Rule_revised.pdf.

38 Consistent with Governor Murphy's Executive Order No. 7 and finalization of the state's RGGI Rule, New Jersey will rejoin RGGI at the start of 2020.

39 *See*, NYISO, IPPTF Carbon Pricing Proposal, dated December 7, 2018, https://www.nyiso.com/documents/20142/2244202/IPPTF-Carbon-Pricing-Proposal.pdf/60889852-2eaf-6157-796f-0b73333847e8.

FIRM RESOURCE ADDITIONS

Any resource that has cleared in a forward capacity auction such as the ISO-NE FCM or PJM Base Residual Auction (BRA) was included as a scheduled addition in the Reference Case. PJM's ongoing matters with FERC have significantly delayed the BRA, but there is currently a capacity surplus in PJM and the uncertainty surrounding resource clearing has limited impact on ISO-NE market.

NYISO does not have a three-year forward capacity auction. NRG's Berrians East Replacement repowering project will replace the Astoria GTs (2-4) with three larger simple-cycle turbines of similar size; the proposed refurbishment was included in the 2019 NYISO Gold Book and has accepted a class year interconnection cost allocation.

Scheduled Renewable and Clean Energy Resource Additions

The Reference Case included all renewable and clean energy projects, including OSW, that have approved contracts and/or which have been selected for long-term contract under a state procurement authority. The in-service date and delivery zone for OSW projects are based on publicly available information. If this information is not in the public domain, then the in-service date was assumed based on milestones provided by other projects, and the delivery location was assumed based on the location of the lease area.

- US Wind and Skipjack OSW projects, with a combined 368 MW of capacity, will deliver into EMAAC (Delmarva Power and Light). Anticipated in-service dates are in 2021 and 2022, respectively. These contracts have been approved by the Maryland Public Service Commission.
- The 130 MW Deepwater Wind's South Fork OSW project will deliver into NY Zone K, with an anticipated in-service date of 2022. The Long Island Power Authority approved the contract.
- The Vineyard Wind 800 MW OSW project has an approved contract and was proposed to have a phased in-service date of January 2022 for the first 400 MW and June 2022 for the remainder of total project nameplate. Vineyard Wind announced on February 11, 2020 that the project schedule will be delayed due to a delay in obtaining the necessary BOEM approval. As a result, it was assumed that the in-service dates will be delayed by one year. Vineyard Wind will deliver into SEMA.
- Deepwater's 700 MW Revolution Wind project was selected by National Grid Rhode Island (400 MW), the Connecticut Clean Energy RFP (200 MW), and the Connecticut Zero Carbon RFP (104 MW). Revolution Wind was assumed to deliver into the Rhode Island RSP subarea and is expected to be placed in-service in 2023.
- The 1,200 MW New England Clean Energy Connect (NECEC) project, selected by the Massachusetts electric distribution companies (EDCs) under the 83D procurement has been approved by the Massachusetts Department of Public Utilities. The stated in-service date is 2023. The annual delivery profile was assumed to be similar to that of Hydro-Québec imports on the Phase II high-voltage direct current (HVDC) tie.
- The 880 MW Ørsted Sunrise Wind and 816 MW Equinor Empire Wind projects were selected in NYSERDA's first offshore wind procurement. Both projects were assumed to be in service in 2024.
- The New Jersey BPU awarded Ørsted a contract for its 1,100 MW Ocean Wind project. Ocean Wind was expected to be operational in 2024 and assumed to deliver into the Atlantic City Electric zone.

- In October 2019 the Massachusetts EDCs selected the Mayflower Wind 804 MW project to enter into contract negotiations. This project was expected to be operational in 2025 and was assumed to deliver into SEMA. The Mayflower project remains subject to approval from the Massachusetts Department of Public Utilities.
- Section 1 of Connecticut Public Act 19-71, An Act Concerning the Procurement of Energy Derived from Offshore Wind, directed the Connecticut Department of Energy and Environmental Protection (DEEP) to solicit offers for up to 2,000 MW of OSW.[40] In December 2019, DEEP selected Vineyard Wind's 804 MW Park City Wind project which was assumed to be delivered into SEMA. The Reference Case assumed commercial operation in 2025. The Park City Wind contract remains subject to approval from the Connecticut Public Utilities Regulatory Authority pursuant to Public Act 19-71.[41]

Except for Connecticut, the Reference Case also included generic resources to meet half of the remaining nameplate needed to meet states' offshore wind targets that have a statutory or regulatory authorization but have not yet initiated a procurement:[42]

- New York State has passed legislation that calls for 9 GW of offshore wind build by 2035. Half of the remaining uncontracted goal, or 3,692 MW, was included as generic OSW resources.
- New Jersey Governor Murphy signed in November 2019 Executive Order No, 92, which increased the NJ OSW goal from 3,500 MW by 2030 to 7,500 MW by 2035.[43] Half of the remaining uncontracted goal, or 3,200 MW, was included as generic OSW resources.
- Maryland passed the Clean Energy Jobs Act of 2019, which calls for the development of 1,200 MW of offshore wind by 2030. Half of this target (which does not include the contracted offshore wind projects), or 600 MW, was included as generic OSW resources.

For each of the OSW projects, the delivery profile was based on NREL Wind Toolkit data applicable to the lease area, as indicated in Table 7.

The Reference Case assumed that no other renewable resources are developed without a contract or a state-authorized procurement, as has been the case in ISO-NE. Therefore, beyond these scheduled additions, no other generic renewables were added to make up any renewable portfolio standard shortfalls in ISO-NE, NYISO, and PJM.

---

[40] Public Act 19-71, An Act Concerning the Procurement of Energy Derived from Offshore Wind, dated June 7, 2020, Section 1, https://www.cga.ct.gov/2019/act/pa/pdf/2019PA-00071-R00HB-07156-PA.pdf.

[41] The inclusion of this project is consistent with the Reference Case for the Integrated Resource Plan (IRP) DEEP is currently undertaking.

[42] As in the IRP, the Reference Case assumes Connecticut utilizes 804 MW from the Park City Wind project out of the 2,000 MW authorized under Public Act 19-71 as the purpose of the IRP is to study and make a schedule for future offshore wind solicitations. Further, the selection of up to 2,000 MW of OSW under Public Act 19-71 is at the discretion of DEEP and subject to approval by PURA.

[43] *See*, Governor Philip Murphy, Executive Order No. 92, dated November 19, 2019, https://nj.gov/infobank/eo/056murphy/pdf/EO-92.pdf.

Firm (Scheduled) Retirements

The scenarios included retirements documented by the RTOs in planning documents and notices. PJM deactivations lists were reflected in the resource mix. NYISO retirement notices and ISO-NE retirement bids through Forward Capacity Auction (FCA) 14 were also reflected in the resource mix.

Mystic units 8 and 9 were assumed to run through the end of the ISO-NE cost-of-service agreement covering FCA 13 and FCA 14 Capacity Commitment Period, and were expected to retire on May 31, 2024. Millstone units 2 and 3 were assumed to retire at the end of the current contracts with the Connecticut EDCs, which expire September 30, 2029.[44]

Approximately 167 MW of older simple cycle units in Connecticut are not expected to comply with the Phase 2 NOx RACT regulations (RCSA sections 22a-174-22e and 22a-174-22f), did not clear in FCA14, and will retire in 2023.

Per New York State's mandate, Indian Point units 2 and 3 will retire in 2020 and 2021, respectively. All other nuclear units are retired when their NRC licenses expire, which generally bring them to 60 in-service years.

All coal units in New York have retired, in part, as a consequence of recently finalized performance standards regarding CO_2 emission limits (6NYCRR Part 251). About 3,000 MW of downstate New York peaking resources are assumed to retire by 2025 resulting from the New York DEC's proposed rule *Ozone Season Oxides of Nitrogen (NOx) Emission Limits for Simple Cycle and Regenerative Combustion Turbines* (6NYCRR Part 227-3).

CAPACITY EXPANSION MODELING

The capacity forecast utilizes Aurora's Long Term Capacity Expansion functionality to determine an equilibrium path of annual resource additions and retirements beyond scheduled additions and retirements. Under this functionality, Aurora calculates the present value of all existing resources and determines which generators are candidates for retirement based on lowest present value over the forecast period. The model iterates to an equilibrium solution given potential candidate new resource options and retirements. In each iteration an updated set of candidate new resource options and retirements is placed into the system and the model performs its chronological commitment and dispatch logic for those resources. The model tracks the economic performance of all new resource options and resources available for retirement based on market prices developed in the iteration. At the end of each iteration the long-term logic decides how to adjust the current set of new builds and retirements, or it determines that the model has converged on an optimal solution. This capacity expansion technique relies on each RTO's planning reserve margin requirements in order to balance supply and demand and maintain resource adequacy.

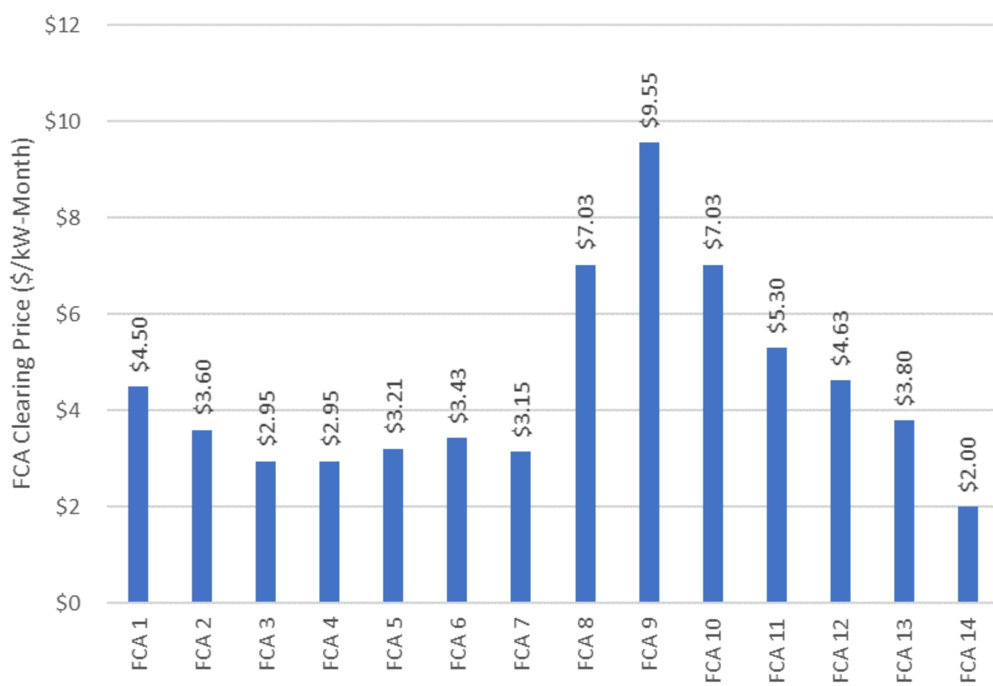
[44] Consistent with the decisions made in the joint study conducted by DEEP and PURA pursuant to June Special Session Public Act 17-3 and PURA Docket No. 18-05-04, DEEP and PURA determined that Millstone is "at risk" of closure absent a long-term contract. The current long-term contract with Millstone expires in 2029.

CAPACITY MARKET IMPACT OF DER

Aurora output can include ISO-level FCA clearing prices, but capacity price formation is subject to many uncertainties including the Competitive Auctions with Sponsored Policy Resources (CASPR) process, results of net Installed Capacity Requirement (ICR) studies, and stakeholder processes such as the triennial review. The triennial review will take place prior to FCA 16 (2022 with a 2025/2026 delivery year) and other reviews of the delist bid threshold and Pay for Performance (PfP) penalty rate will be done prior to FCA 15 (2021). It is therefore difficult to forecast capacity prices without the necessary simplifying assumptions.

The structure of the ISO-NE capacity market has been in flux since FCA 8, when the FCA price floor was removed and administrative pricing rules were triggered to determine the clearing price. While clearing prices for the first few years with a sloped demand curve were higher than had been observed in earlier FCAs, clearing prices have been falling in spite of the introduction of PfP, Minimum Offer Price Rule (MOPR), and the introduction of the substitution auction through the CASPR initiative. The substitution auction, a concept introduced to provide a path for existing resources to exit the capacity market by substituting out for a policy-sponsored resource, was introduced in FCA 13 and resulted in a 54 MW capacity commitment award to Vineyard Wind. Despite FCA 14 clearing at the lowest ever capacity clearing price as shown in Figure 9, FCA 14's substitution auction did not clear any capacity.

Figure 9: Historical FCA Clearing Prices (nominal $)



There are only 19 MW of capacity remaining for FCA 15 under the renewable technology resource (RTR) exemption, which allows certain renewable resources such as solar PV to bid into the FCA without being subject to MOPR. Considering that there are several renewable projects under contract in Connecticut and other ISO-NE states without a Capacity Supply Obligation, the seeming willingness of conventional generating resources to remain in the market despite historically low capacity prices, and the small amount of available RTR capacity that remains available for FCA 15, there is no guarantee that any of the DER included in the Study would clear the FCA as a supply-side resource.

Given the uncertainties surrounding potential changes in capacity market design or demand and supply dynamics and the difficult path to clearing upcoming FCAs faced by renewable resources, capacity price forecasts from Aurora were not used to derive the capacity market value for each DER type evaluated in the Study. Instead, the market impact, or Demand Reduction Induced Price Effect (DRIPE), and avoided generation capacity payment benefit were calculated using a spreadsheet model with the recognition that any forecasted capacity demand curves will be subject to considerable uncertainty. The methodology for these calculations is discussed in Section II.

ISO-NE's system-wide Marginal Reliability Impact (MRI) demand curve from FCA 14 provides the basis of the demand curve forecast. The range of the annual MRI curve bounded by the FCA10 outcome of $7.03/kW-Month and the FCA 14 clearing price of $2/kW-month represents the plausible range of capacity clearing prices for which the capacity DRIPE and avoided generation capacity payment benefit of each DER type was evaluated. Capacity DRIPE calculations were subject to a benefit decay schedule under which the capacity benefit of the DER was phased out over six years as suggested in the 2018 Avoided Energy Supply Components in New England study.[45]

ADDITION/ATTRITION FORECASTING

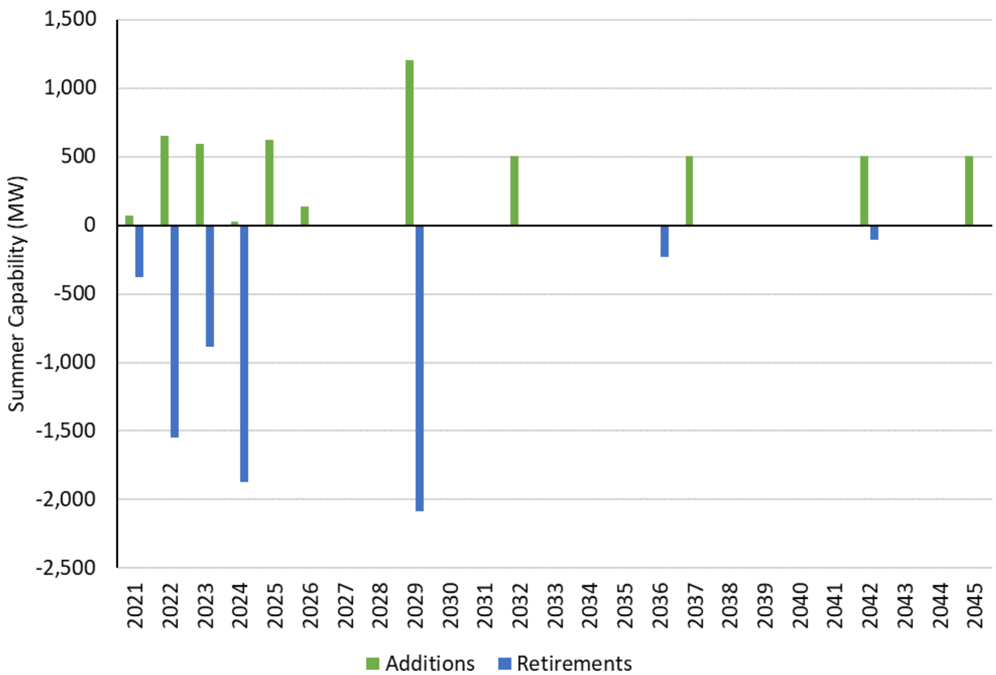
The Aurora capacity expansion model was applied to determine if generic resources are needed to meet reserve margin targets. Candidate resources were modeled based on the CONE study combined cycle and simple cycle combustion turbine units for the respective RTO. Candidates for retirement were limited to coal and oil-fired steam turbines, which ISO-NE has identified as "at-risk."

[45] Synapse Energy Economics, Inc., Resource Insight, Les Deman Consulting, North Side Energy, and Sustainable Energy Advantage, Avoided Energy Supply Components in New England: 2018 Report, dated October 24, 2018, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf.

Reference Case Results

Figure 10 provides an annual-level overview of planned and economic retirements and additions represented by total MW of summer capability.[46] This represents the resource balance that resulted from running Aurora's long-term capacity expansion function and that was used to model the Reference Case, as described above, and all six DER Use Cases, as described in Appendix B. New England Clean Energy Connect was assumed to obtain a Capacity Supply Obligation (CSO) in 2029 through a transfer of a portion of the Millstone units' CSO in the FCM Substitution Auction. Four gas-fired resources were added in ISO-NE in order to maintain system reliability between 2032 and 2045.

Figure 10: Annual Resource Additions and Retirements



Reference Case results reflect the modeling assumptions described in greater detail above. Figure 11 provides the baseline annual electric generation of units located in all of ISO-NE and units located in Connecticut. Figure 12 through Figure 15 provide the annual emissions from facilities located in Connecticut and in all of ISO-NE. These figures provide the baseline generation and emissions used to compare avoided generation and avoided emissions resulting from the six DER Use Cases included in the Study. The increase in emissions of CO_2, NO_X, and $PM_{2.5}$ in 2029 reflect the assumed retirement of Millstone. The variation in SO_2 emissions results from operation of coal units following the retirement of the Mystic units.

[46] Capacity Supply Obligations in ISO-NE's forward capacity market are based on a resource's expected reliable contribution during peak hours; therefore, summer capability is used to determine whether reliability targets are met and whether resources should be added. Summer capability varies by resource type and reflects the expected output of the resource during peak summer conditions.

Figure 11: Reference Case Annual Total Generation

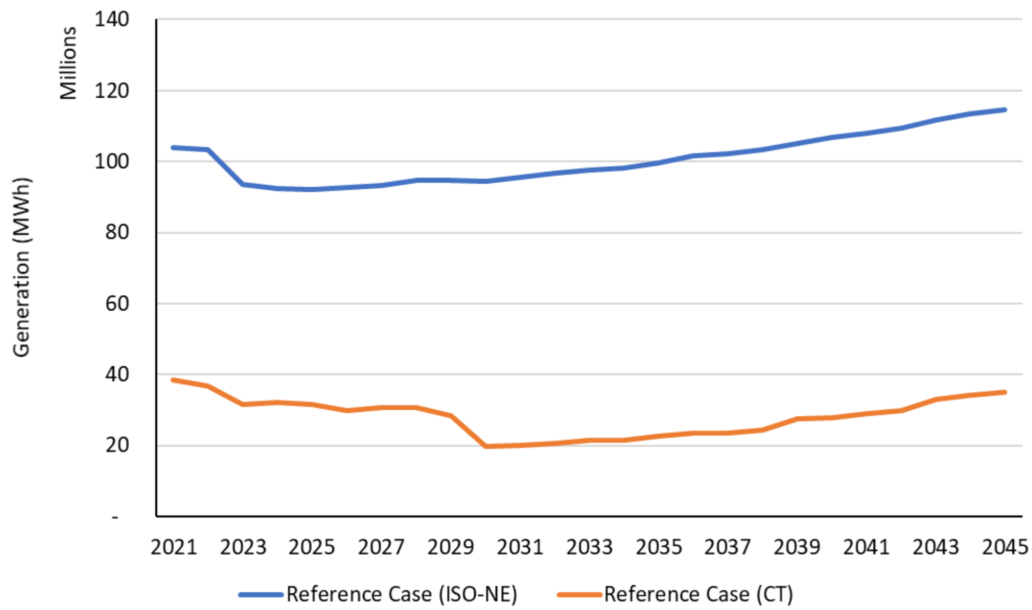


Figure 12: Reference Case Annual CO_2 Emissions

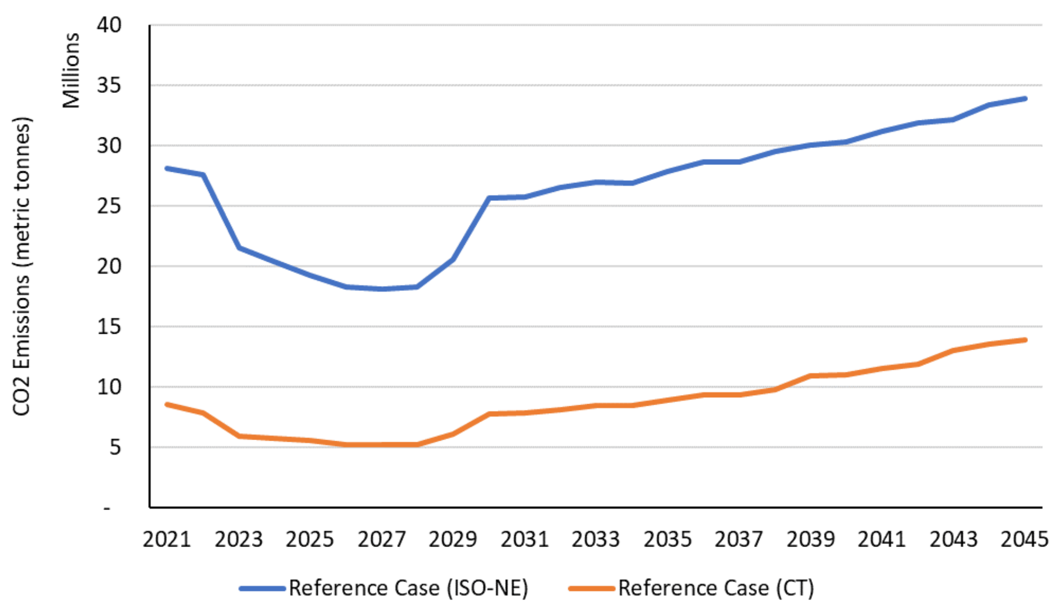


Figure 13: Reference Case Annual NO_X Emissions

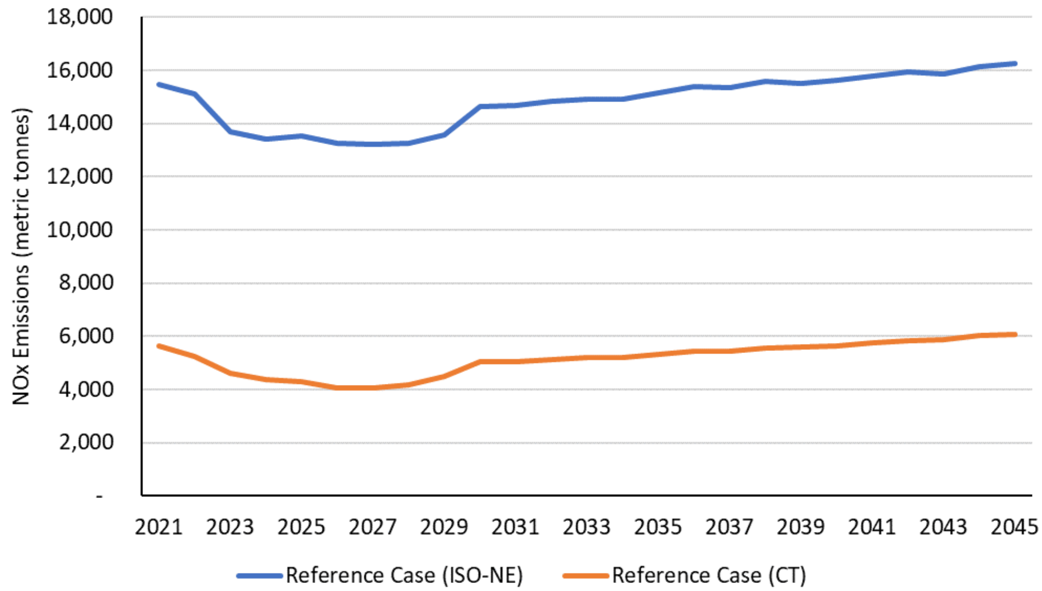


Figure 14: Reference Case Annual $PM_{2.5}$ Emissions

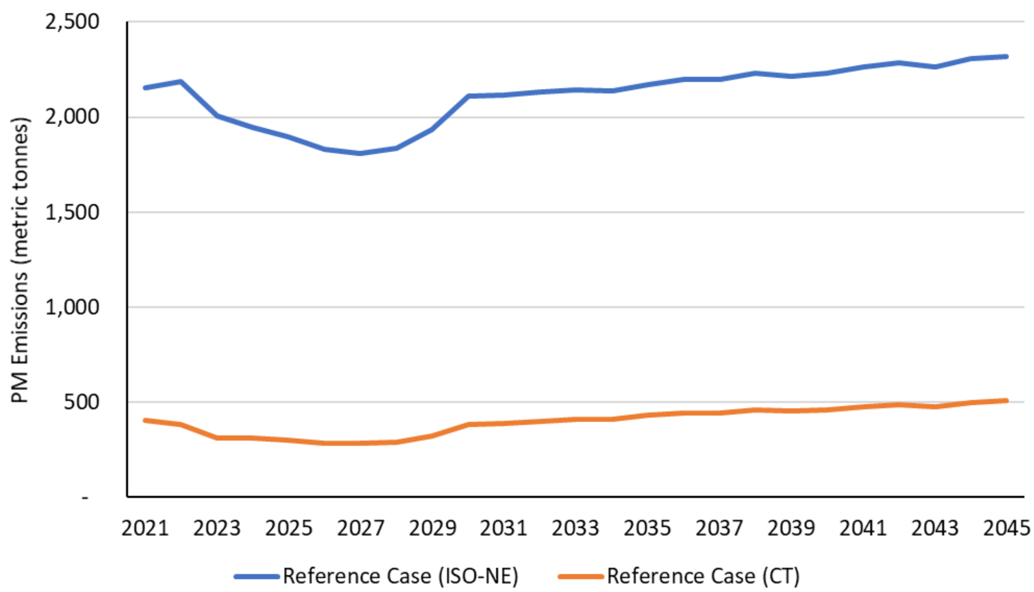


Figure 15: Reference Case Annual SO_2 Emissions

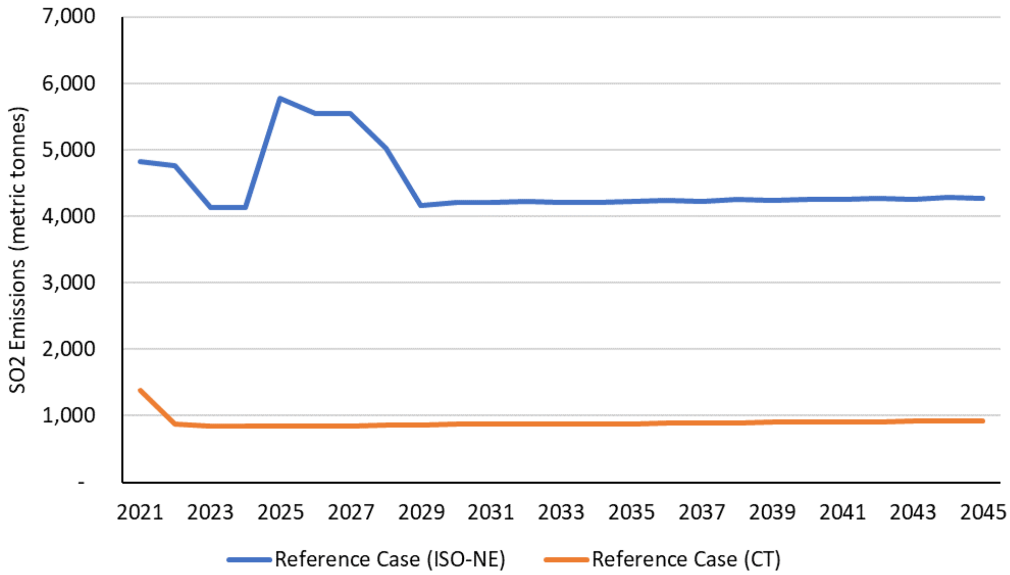
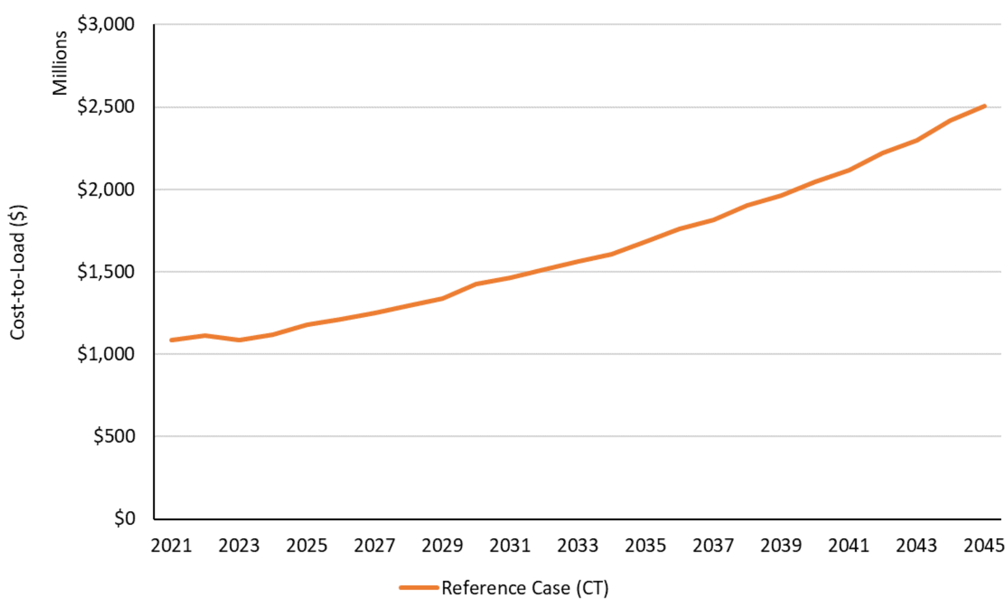


Figure 16 provides the annual Connecticut load costs for wholesale energy for the Reference Case in nominal dollars. Annual load costs represent the total expected energy costs required to serve Connecticut load. Annual load cost is calculated as the product of the hourly energy price and hourly demand, which are summed over the year. Load cost in this document is also referred to as "cost-to-load." Reference Case Connecticut load costs serve as a baseline to which Use Case Connecticut load costs can be compared.

Figure 16: Annual Connecticut Load Costs (nominal $)



Appendix B. DER Technology Use Cases and Quantitative Values

APPROACH TO TECHNOLOGY USE CASES

This Appendix defines six DER Use Cases used in the dispatch modeling for the Study. Each Use Case modeled annual incremental capacity additions of 100 MW of a particular type and use of a DER technology, combination of DER technologies, or EE in Connecticut. The 100 MW increments were added over a ten-year timeframe, from 2021 through 2030, resulting in total incremental capacity additions and/or load reduction for each Use Case of 1,000 MW. This approach creates a uniform deployment of resources to compare their relative values, as appropriate, based on MW deployment. Results for each Use Case were derived by comparing the Use Case model run to the Reference Case. As with the Reference Case, each Use Case was run through 2045 with no incremental DER or EE capacity additions modelled after the first ten years.

As noted in Appendix A, the Reference Case does not include any DER technology deployment in Connecticut over the study period, as the Study seeks to inform future DER policies and programs that would deploy incremental DERs in the state. The Reference Case does include a forecast of EE deployment in Connecticut over the study period, as the Study seeks to inform future EE policies and procurements that are incremental to the Conservation and Load Management Plan.

The Use Case dispatch modeling results are summarized in Section II. and are provided, with other modeling outputs, in the Excel workbooks appended as Appendix B.I. through Appendix B.VI. to the Study. The hourly production profiles for each Use Cases are provided in the worksheets titled, "UC Gen&Energy Revenue Hourly," included in Appendix B.I. through Appendix B.VI. for Use Case (UC)1 through UC6, respectively. The data sources for the hourly production profiles for each UC are summarized in Table .

Table 1: DER Technology Use Cases and Date Sources

Technology Use Case	Data Source(s)
(1) Behind-the-Meter (BTM) Solar Photovoltaic (PV)	2018 and 2019 historical production data from the Connecticut Green Bank (see footnote below)
(2) Front-of-the-Meter (FTM) Solar PV	Aggregated data provided to DEEP in recent procurements
(3) BTM Solar PV Paired with Electric Storage	Data from Use Case (1) overlaid with residential electric storage assumptions from slide 8 of Connecticut Green Bank's 11/13/19 presentation in Docket No. 17-12-03RE03
(4) FTM Electric Storage	Data from commercially available systems
(5) Fuel Cell	Aggregated data provided to DEEP in recent procurements
(6) Energy Efficiency	N/A (see description below)

UC1: BTM Solar PV

This Use Case utilizes historical production data from the Connecticut Green Bank residential BTM solar installations in Connecticut to extrapolate production profiles and to distribute the resources among sub-areas across the state. Consistent with the ISO-NE BTM PV Forecast, MW-ac capacity values were used for incremental BTM solar additions. Annual incremental solar additions of 100 MW-ac were distributed across the three Connecticut sub-areas based on the relative share of residential solar installations. Table 2 provides a summary of the residential solar installations provided by the Connecticut Green Bank for 2017 and 2018, as well as the relative share of the installations in each sub-area over the two years of data.

Table 2: Nameplate (MW-ac) of Zonal Residential Solar Installations

RSP Sub-Area	2017	2018	Share
Central Connecticut	15.35	20.15	52.1%
Norwalk	1.35	1.42	4.1%
Southwest Connecticut	12.50	17.48	43.8%
Total	29.20	39.05	100.0%

100 MW-ac of incremental BTM solar was added each year with 52.1 MW sited in central Connecticut, 4.1 MW sited in Norwalk, and 43.8 MW sited in southwest Connecticut.

Data from the Connecticut Green Bank on the production of the residential systems referenced in Table 2 was used to develop the energy generation profile.[1] A statewide production profile was created using the 2018 and 2019 annual production from Connecticut Green Bank residential installations that occurred in 2017 and 2018, respectively. The profile is based on the MW-ac generation rating and is grossed up 6.5 percent to reflect avoided transmission and distribution losses consistent with ISO-NE's 2019 PV forecast.[2] Further, consistent with NREL data and the Connecticut Green Bank's long-term forecast, a 0.5 percent yearly PV degradation rate was applied for each incremental addition of production.[3] The production profile created using the Connecticut Green Bank data was also used to model existing BTM solar in Connecticut in the Reference Case and all Use Cases.

UC2: FTM Solar PV

Aggregated production data from FTM solar PV systems was used to develop the hourly energy profiles for this Use Case. The data was aggregated from energy profiles from proposals for solar PV projects 20 MW and less connected to the electric distribution system in Connecticut, which were submitted in response to DEEP's Zero Carbon procurement pursuant to Conn. Gen. Stat. § 16a-3m. A 0.5 percent annual PV degradation rate was also applied over the forecast period. Consistent with the proposals, each annual increment of 100 MW of FTM solar PV added in this Use Case was sited in the Connecticut Central Regional

---

[1] *See*, Docket No. 19-06-29, Interrogatory Responses, dated April 2 and 3, 2020, http://www.dpuc.state.ct.us/dockcurr.nsf/(Web+Main+View/All+Dockets)?OpenView&StartKey=19-06-29.

[2] *See*, ISO-NE, Final 2019 PV Forecast, dated April 29, 2019, https://www.iso-ne.com/static-assets/documents/2019/04/final-2019-pv-forecast.pdf.

[3] *See*, National Renewable Energy Laboratory, STAT FAQs Part 2: Lifetime of PV Panels, dated April 23, 2018, https://www.nrel.gov/state-local-tribal/blog/posts/stat-faqs-part2-lifetime-of-pv-panels.html.

System Plan (RSP) sub-area. Also, as these systems were treated as supply resources, the generation was not grossed up to reflect avoided transmission and distribution losses.

UC3: BTM Solar PV Paired with Electric Storage

This Use Case utilized the data and production profiles from UC1 for BTM solar PV and overlaid assumptions relating to residential energy storage systems (ESS) on top of the BTM solar PV production profiles. This Use Case also used the same assumptions as UC1 for PV degradation and the same assumptions as UC6 for avoided transmission and distribution losses (*i.e.* 8 percent). In total, this Use Case deployed 1,000 MW of BTM solar PV and 500 MW in residential ESS from 2021 through 2030.

Operating parameters for the paired ESS are summarized in Table 3. Values shown in Table 3 represent the PV and ESS for an individual residential installation of 8.0 kW (DC), and were scaled for the total ESS added (*i.e.* 50 MW per year, for a total of 500 MW over the Use Case).

Table 3: ESS Operating Parameters[4]

System Specification	
BTM PV power	8.0 kW (DC)
ESS power	4.0 kW
ESS energy	10.0 kWh
ESS efficiency	92%
ESS duration	2.5 hr
ESS available energy	8.0 kWh
ESS available duration	2.0 hr
ESS backup reserve	20%
ESS backup energy	2.0 kWh
ESS backup duration	0.5 hr

Aurora scheduled the paired storage resources with the constraint that the storage resource may only be charged from the BTM resource. The storage resource was dynamically scheduled to dispatch during the highest-priced hours.

Based on the analysis submitted by the Connecticut Green Bank regarding BTM solar systems paired with electric storage,[5] the Agencies considered multiple discharging constraints for this Use Case such as the constraint the Green Bank used of limited ESS production to on-site load. In hopes of analyzing a unique

[4] Adopted from Connecticut Green Bank's presentation: Docket No. 17-12-03RE03, dated November 13, 2019, p. 8. *See also*, Docket No. 19-06-29, Connecticut Green Bank Written Comments, dated February 14, 2020, Attachment 1, p.14, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/375693d69d27ed4785258512005fc568/$FILE/CT%20Green%20Bank%20complete%20comment3%20021420.pdf.

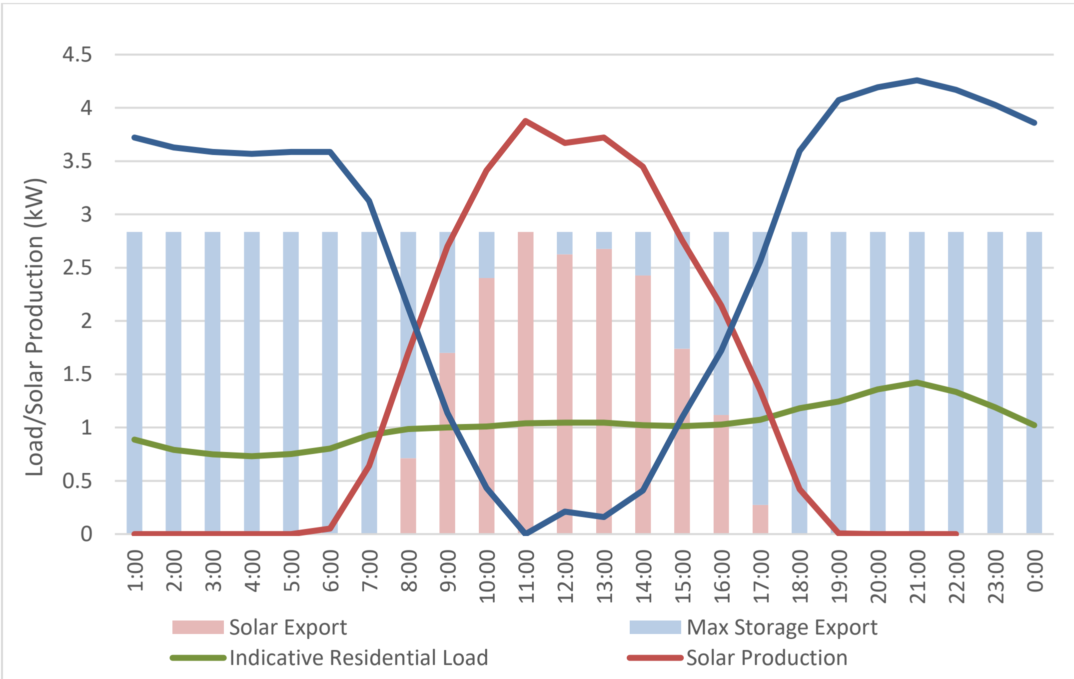
[5] *See*, Connecticut Green Bank Written Comments, dated February 14, 2020, Attachment 1, p. 35, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/375693d69d27ed4785258512005fc568/$FILE/CT%20Green%20Bank%20complete%20comment3%20021420.pdf.

discharging constraint that allowed for greater ESS dispatchability, the Agencies evaluated the following hourly dispatch constraint:

$$ESS_{\text{hourly max production}} = [\text{Solar PV} - \text{Load}_{\text{residential customer}}]_{\text{max}} - \text{Solar PV}_{\text{hourly production}}$$

Figure depicts the considered dispatch constraint for an illustrative day in April.

Figure 1: Illustrative Graph of Considered BTM Storage Dispatch Constraint (Illustrative April Day)[6]



The Agencies explored the use of such a dispatch constraint as exported power from any BTM system has implications for the distribution system. More specifically, any increase in exported power due to the inclusion of an ESS above a standalone BTM solar PV system has the potential to incur additional distribution system upgrades and to increase the complexities of the utility's interconnection process. This dispatch constraint would mitigate these implications while allowing the ESS to be dispatched during more peak hours.

A post-processing review of an unconstrained ESS dispatch for this Use Case showed only 18 hours where this constraint would have been exceeded, over more than 9,000 modeled days, and many of the exceedances were minimal. As such, the Agencies felt it was appropriate to use data from the unconstrained ESS dispatch model run for this Use Case.

---

[6] This graph does not illustrate the charging constraint used for this Use Case.

UC4: FTM Electric Storage

This Use Case utilized operating parameters and performance data in the public domain for a commercially available 4-hr storage system.[7] The ESS for this Use Case was installed in a FTM configuration in 100 MW increments within the Connecticut load zone. In order to maximize wholesale energy revenues, Aurora dynamically scheduled storage to dispatch during the highest-priced hours. As these systems were treated as supply resources, the generation was not grossed up to reflect avoided transmission and distribution losses.

UC5: Fuel Cell

Aggregated data from fuel cell proposals submitted in DEEP's 2018 Best-in-Class procurement were used to determine input parameters including heat rates, expected degradation and outage rates, and emissions rates. For the 1,000 MW of FTM fuel cell capacity studied in this Use Case, a weighted average heat rate of 7,284 Btu/kWh was used. Based on stakeholder comments provided by Bloom Energy, fuel cells were modeled to run at full capability after accounting for maintenance outages and degradation.[8] The 6.25 percent outage rate used to model FTM fuel cells in this Use Case was derived by taking a weighted average of the outages provided in the Best-in-Class procurement bids. Maintenance cycles and fuel cell degradation was accounted for by modeling a constant levelized annual outage rate. Emissions rates shown in Table 4 were also derived from aggregated data provided in submissions to the Best-in-Class procurement.

Table 4: Fuel Cell Emissions Rates

Pollutant	Rate (lb/mmBtu)
CO_2	113.4
NO_x	0.0014
SO_2	0.0006
$PM_{2.5}$	0.00009

The annual incremental 100 MW of FTM Fuel Cell capacity was apportioned to the three Connecticut RSP sub-areas based on the location of existing Connecticut fuel cell capacity in the 2018 EIA-860 data.[9] Each 100 MW increment of fuel cell nameplate capacity added was spread across the Connecticut sub-areas as follows: 55.36 MW in Central Connecticut, 42.57 MW in Southwest Connecticut, and 2.07 MW in Norwalk.

---

[7] *See*, Tesla, Powerpack: Utility and Business Energy Storage, https://www.tesla.com/powerpack.

[8] Based on the same comments from Bloom Energy, the Agencies understand that BTM and FTM fuel cell operation is similar and, thus, did not distinguish between the two in this Use Case. The only impactful difference in relation to the dispatch modeling, of which the Agencies are aware, is the treatment of distribution and transmission losses. As a rough approximation, the wholesale energy market outcomes presented in Section II. of the Study could be grossed up by 6.5 - 8 percent to account for this difference.

[9] *See*, U.S. Energy Information Administration, Form EIA-860 detailed data with previous form data (EIA-860A/860B), https://www.eia.gov/electricity/data/eia860/.

UC6: Energy Efficiency

Because production data varies greatly depending upon the energy efficiency measure implemented, this Use Case modeled incremental load reduction consistent across all hours, resulting in 1,000 MW of cumulative reduced load in all hours after the ten-year deployment modeled in these Use Cases. This approach to modeling load reduction consistent across all hours helps policymakers and regulators to identify and quantify the benefit of reducing load in each hour over the forecast period and at various levels of demand. Ultimately, the modeling performed for this Use Case can inform future program design by providing a resource to quantify the energy efficiency measures that are most valuable and which hours should be targeted for demand response programs.

The annual incremental 100 MW of EE capacity was apportioned to the three Connecticut RSP sub-areas based on the 2019 CELT and were grossed up 8 percent, from 926 MW, to reflect avoided transmission and distribution losses consistent with ISO-NE's load forecast methodology.[10] EE additions modeled in this Use Case were incremental to the EE deployment forecasted for Connecticut in the 2019 CELT forecast period.

[10] ISO-NE, Long-Term Load Forecast Methodology Overview, dated September 27, 2019, p. 16, https://www.iso-ne.com/static-assets/documents/2019/09/p1_load_forecast_methodology.pdf.