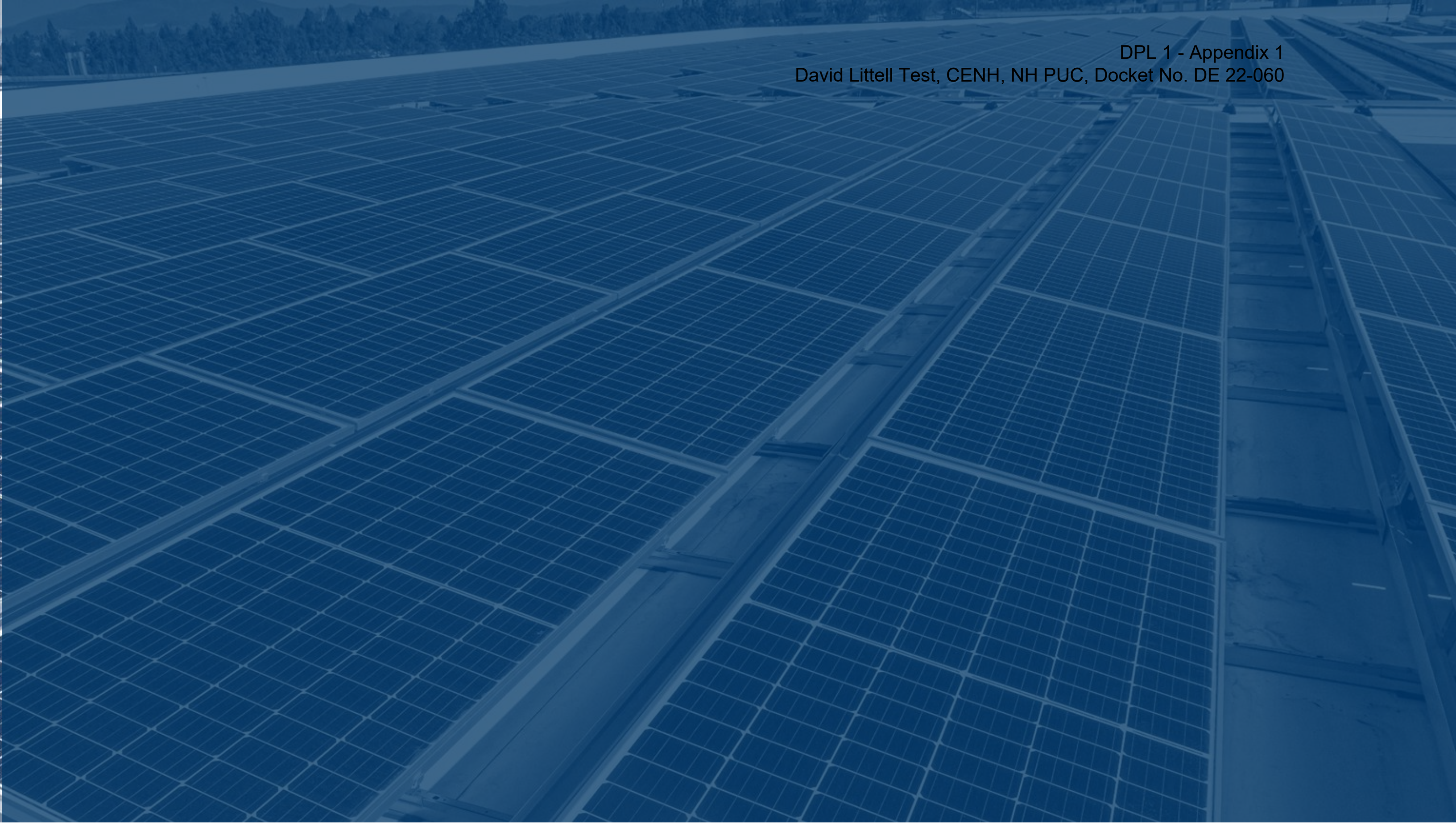

New Hampshire Value of Distributed Energy Resources

Final Report

Submitted to:

New Hampshire Department of Energy

www.energy.nh.gov

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With support from Power Advisory

About Dunsky

Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

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Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

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List of Acronyms

AESC	Avoided Energy Supply Costs
BTM	Behind-the-Meter
CO_2	Carbon dioxide
DER	Distribution Energy Resource
DG	Distributed Generation
DRIPE	Demand Reduction Induced Price Effect
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
GHG	Greenhouse Gas
HE	Hour Ending
HLGS	High Load Growth Scenarios
ISO-NE	Independent System Operator – New England
kWh	Kilowatt-hour
LGHC	Large Group Host Commercial
LMP	Locational Marginal Price
LNS	Local Network Service
LSEs	Load Serving Entities
MRVS	Market Resource Value Scenario
MW	Megawatt
NEM	Net Energy Metering
NO_x	Nitrogen oxide
PTF	Pool Transmission Facilities
PUC	Public Utilities Commission
RGGI	Regional Greenhouse Gas Initiative
RNS	Regional Network Service
ROC	Rest of Criteria
RPS	Renewable Portfolio Standard
SO_2	Sulfur dioxide
T&D	Transmission and Distribution
VDER	Value of Distributed Energy Resources

EXECUTIVE SUMMARY

Introduction

The New Hampshire Value of Distributed Energy Resources (VDER) study assesses the value of behind-the-meter (BTM) Distributed Energy Resources (DERs) that are owned by customers-generators and are eligible to participate in net energy metering (NEM) programs in New Hampshire. Statewide value is assessed from the perspective of the utility system and – through a rate and bill impact analysis – from the perspective of New Hampshire ratepayers, both NEM participants and non-participants.

This report answers the following key questions (with relevant study component indicated in brackets):

- **What are the system-wide avoided cost values of net-metered DERs installed during the 15-year study period to the utility system in New Hampshire?** (base value stack)
- **How does this value change if environmental externalities are considered?** (environmental externalities sensitivity)
- **How does this value change if system-wide loads increase?** (high load growth scenarios)
- **How does this value change with participation in the ISO-NE regional wholesale markets?** (market resource value scenario)
- **How do net-metered DERs impact ratepayers under the current NEM tariff structure and how would that impact change under an alternate compensation structure?** (rate and bill impacts analysis)

Methodology Overview

The VDER study methodology framework can be summarized by five high-level steps, outlined below:

First, baseline technology-neutral avoided cost values are established (step 1). Next, DER production curves are developed for each resource type (step 2) and mapped against the technology-neutral avoided costs to calculate the avoided cost value of DERs by system type (step 3). Avoided cost values are also calculated under sensitivity cases, including consideration of environmental externalities, high load growth scenarios, and a market resource value scenario (step 4). Finally, the rate and bill impacts are assessed, determining how DER deployment and compensation will affect New Hampshire rates and customer bills (step 5).

Key Findings

The results provided in this section are illustrative. The values presented below are calculated using specific sample system types, which were selected to be representative of common systems installed in the state. Specifically, the system types modeled were: residential and commercial south-facing solar PV (with and without storage), residential and commercial west-facing solar PV, large group host commercial (LGHC) solar PV, and micro hydro. The system specifications can be found in the 'Establishing DER Production Profiles' section of this report.

Although this approach is useful in highlighting trends, it does not generate values that can be applied to other system types. The model that accompanies this report allows users to generate results specific to other system types using a custom production profile.

In New Hampshire, the DER systems modeled for this study are expected to have provided a total system-wide net avoided cost value of **$0.11 to $0.18 per kWh energy produced in 2021** (Figure 1) and are forecasted to provide **$0.10 to $0.23 per kWh produced in 2035** (Figure 2), varying by DER system type:

Figure 1. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2021 (2021$)

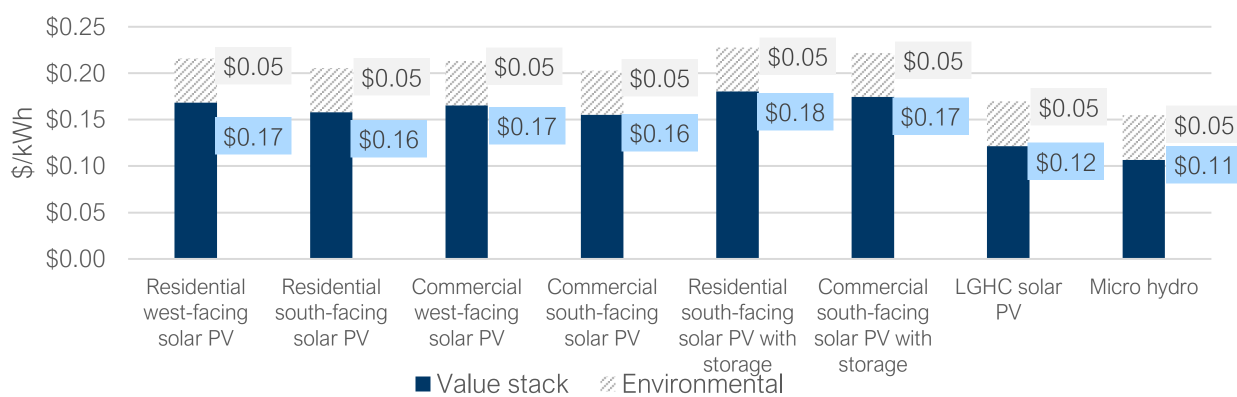
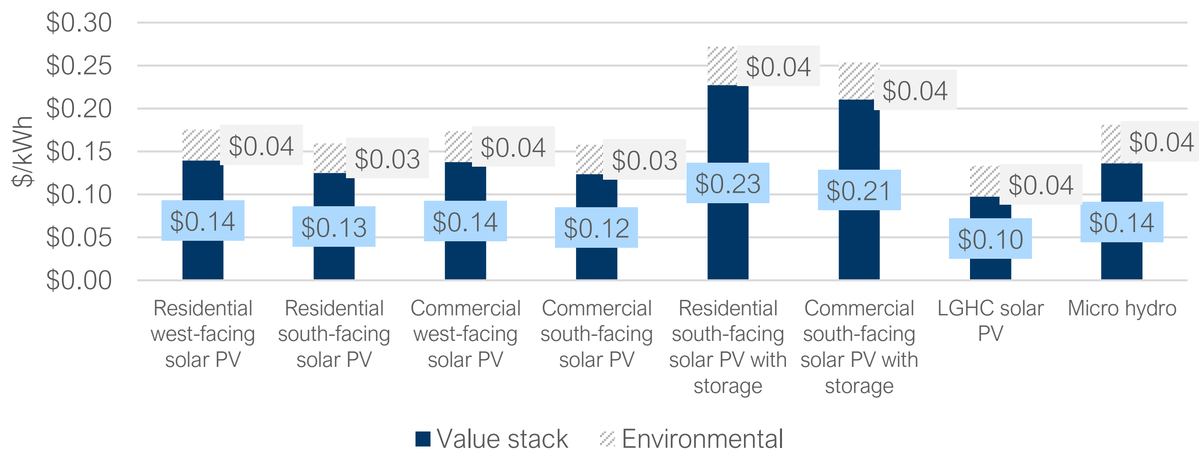


Figure 2. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2035 (2021$)



The total avoided cost value stack *decreases* over the study period for solar-only systems, primarily as a result of decreasing energy avoided costs. Net-metered DER value *increases* over time for solar paired with storage and for micro hydro as a result of the ability of those systems to realize greater Transmission and Distribution (T&D) avoided costs, which are assumed to increase over the study period. If the full social cost of environmental externalities (CO2, NOx) is considered, the value of net-metered DERs increases by 20%-45%, varying by year and by DG system type.

Although west-facing solar PV systems provide 5-10% greater avoided cost value by generating electricity later in the day (at times of peak demand), customer-generators in New Hampshire are currently incentivized to maximize solar production by installing south-facing systems, as these systems produce a greater volume of electricity overall.

Avoided cost values may change as a result of increasing system loads or should DERs participate in the regional wholesale energy or capacity markets. The impacts of these factors were assessed through the high load growth scenario (HLGS) and the market resource value scenario (MRVS), respectively. The change in avoided cost value from the baseline value stack for those scenarios is shown for 2021 in Figure 3 and for 2035 in Figure 4 below.

Figure 3. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2021 (2021$)

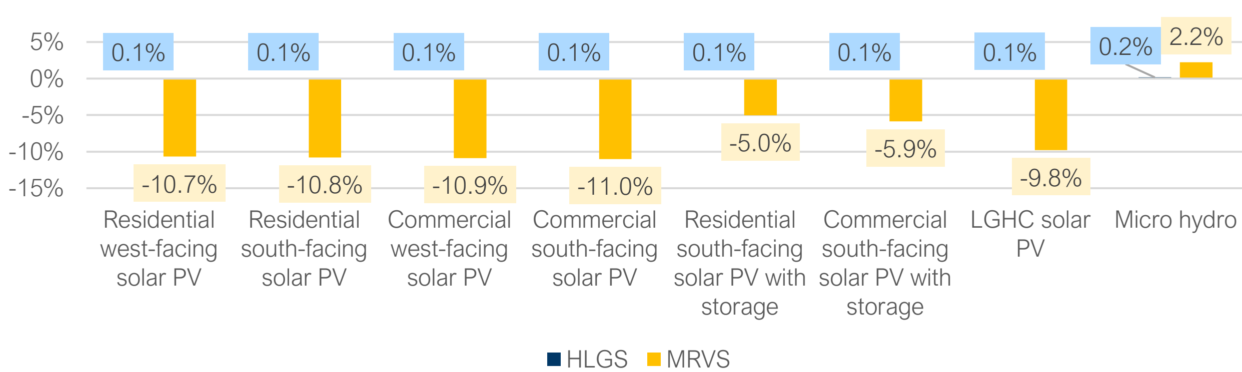
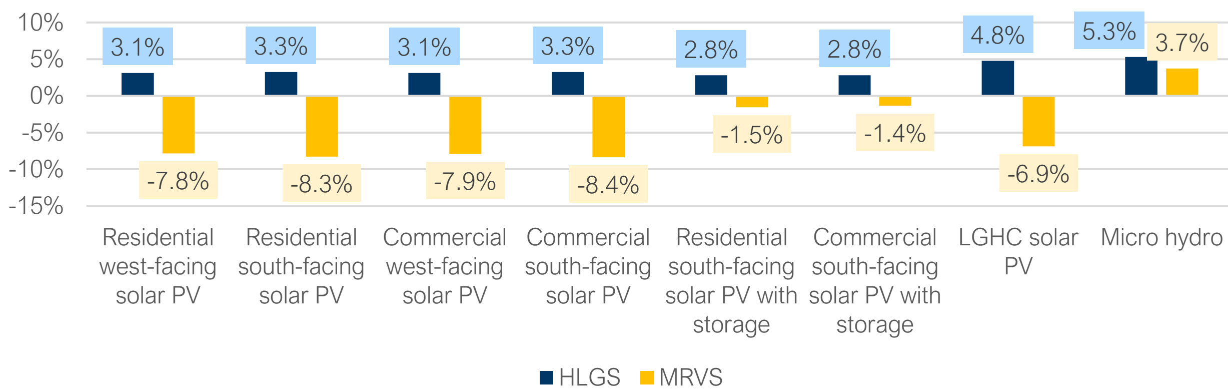


Figure 4. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)



Increased loads under high load conditions, reflecting increased building and transportation electrification, have minimal impacts on the value of DERs in 2021 (less than 1% difference). In 2035, increased loads drive 2.8% to 5.3% higher values than the baseline value stack, varying by system type. The environmental externalities avoided cost sensitivity is also assumed to change with loads, increasing in value as loads grow due to assumptions that higher-emitting resources will be required to meet the incremental demand.

Net-metered DERs also may participate in the wholesale markets, rather than acting merely as passive resources that generate avoided cost value by reducing customer loads. From a utility system perspective, under current market rules, all systems provide greater value by passively reducing load than by participating as aggregated resources in the wholesales markets, with the exception of micro hydro. Micro hydro plants are able to consistently generate energy during the summer and winter reliability periods, thereby increasing their value in the forward capacity market.

Net-metered DERs are expected to provide value beyond what is shown here, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services, and resiliency. Additional research and data collection may support valuation of these criteria in the future.

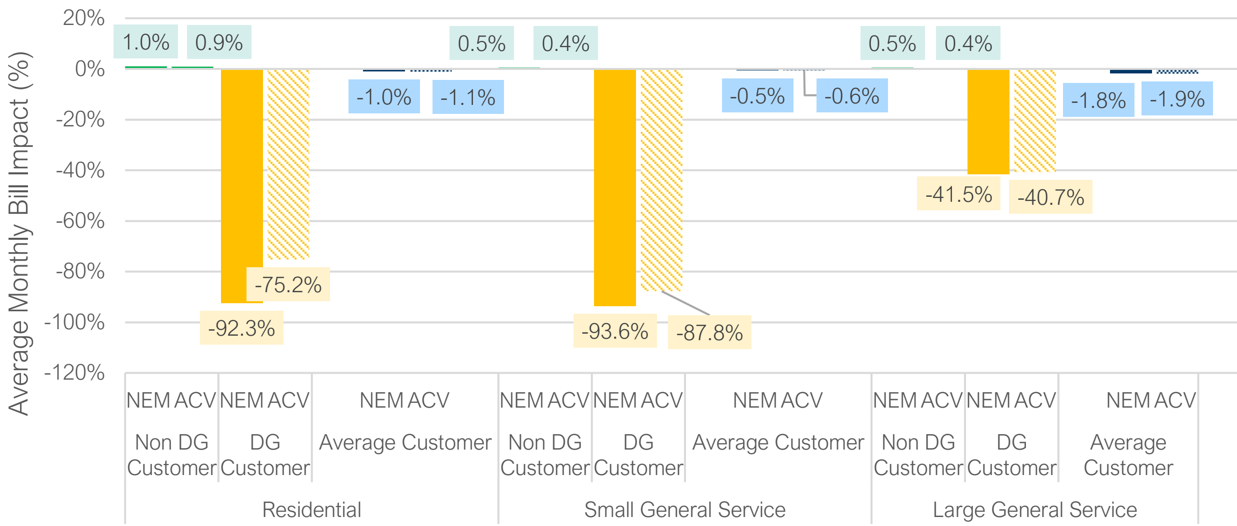
Customer-installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[1]

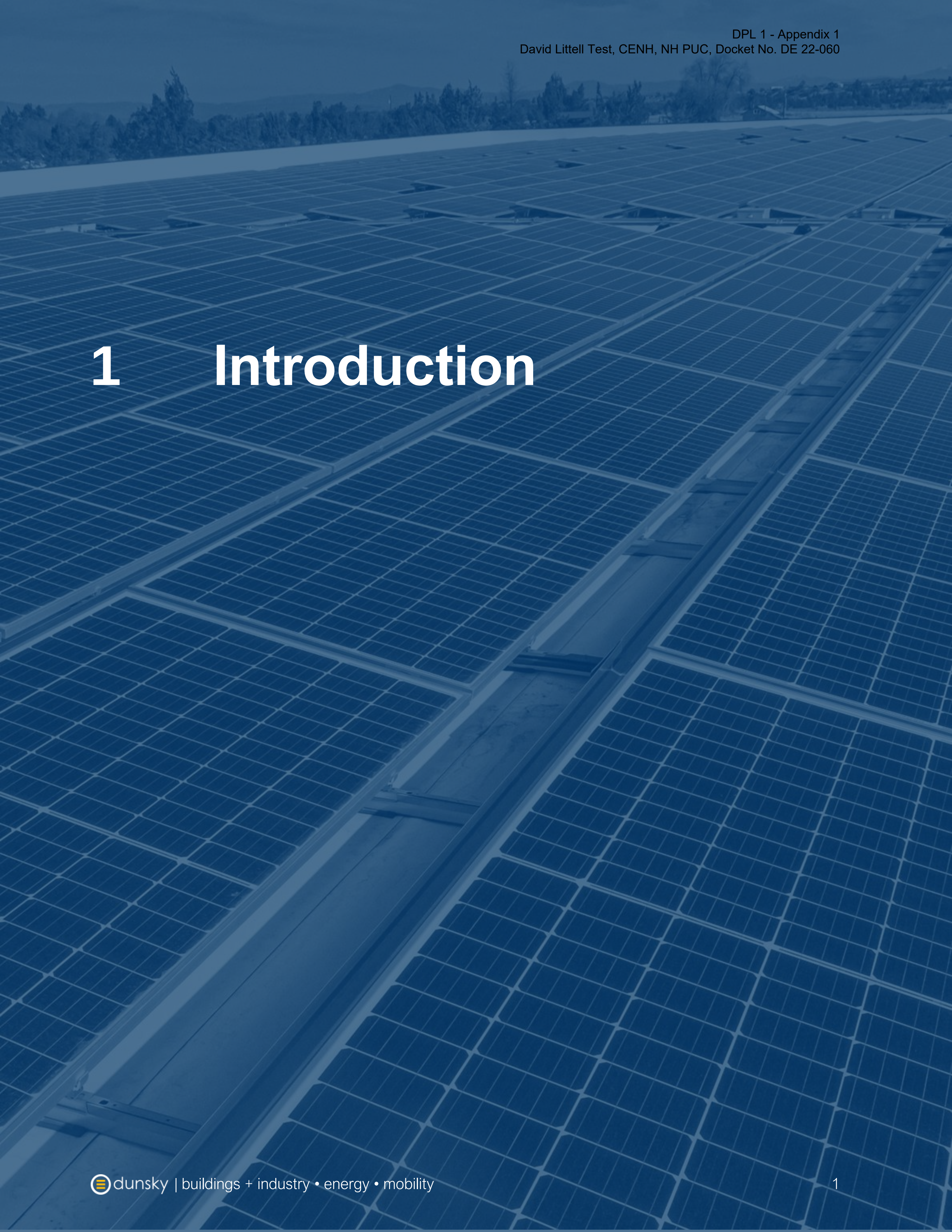
The rate and bill impacts analysis demonstrate that DG will cause rates to increase slightly for all rate classes and across all utilities under the current alternative net metering tariff design. Monthly bills would increase by a small percentage for non-DG customers but would decrease by a larger percentage for DG customers. . The average impact across each customer class, referred to as the “average customer” impact, is expected to be a bill reduction. In the alternative, a compensation model based on the avoided

[1] NH House Bill 1116 (2016). Available online: https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2016&id=293&txtFormat=html

cost value stack (i.e., an ACV tariff approach) would slightly reduce rate increases experienced by customers, with virtually the same non-DG customer impacts but slightly lower bill savings for DG customers, which would be reduced to a greater degree – in particular for residential customers (Figure 5).

Figure 5. Bill Impacts Across Rate Classes in Eversource Territory Under ACV and NEM Scenarios (Relative to no-DG scenario)





1 Introduction

Introduction

The New Hampshire Value of Distributed Energy Resources (VDER) study assesses the value of behind-the-meter (BTM) Distributed Energy Resources (DERs) that are owned by customers-generators and that are eligible for compensation through net energy metering (NEM) programs.[2] Statewide value is assessed from the perspective of the utility system and – through a rate and bill impact analysis – from the perspective of New Hampshire's ratepayers.

DG systems can generate energy and thereby decrease utility load, reducing the total demand that must be met by New Hampshire's utilities – and the ISO New England (ISO-NE) wholesale markets. This can reduce utility costs, generating avoided cost values.[3,4] The value that such DERs provide is location- and time-dependent, varying by hour, season, and year. These variations result from changing conditions in the ISO-NE wholesale markets and within New Hampshire's transmission and distribution systems, including resource availability, demand, congestion, and infrastructure. This statewide study *does not* capture variation by specific locations within New Hampshire, which was evaluated in a separate study completed for New Hampshire in 2020.[5] The study *does* capture variation in value by time by quantifying average state-wide hourly avoided cost value stacks from 2021 to 2035. The value that a net-metered DER can generate depends on the coincidence of its energy production/load reduction with the hourly avoided cost value stacks. This study maps hourly load reductions to hourly avoided costs for a sample of DERs that are generally representative of the system types participating in New Hampshire's NEM program.

This report answers the following key questions (with relevant study component indicated in brackets):

- **What are the system-wide avoided cost values of net-metered DERs installed during the 15-year study period to the utility system in New Hampshire?** (base value stack analysis)
- **How does this value change if environmental externalities are considered?** (environmental externalities sensitivity analysis)
- **How does this value change if system-wide loads increase?** (high load growth scenario analysis)
- **How does this value change with direct participation in the ISO-NE wholesale power markets?** (market resource value scenario analysis)
- **How do net-metered DERs impact rates and customer bills, and how do those impacts change under an alternate compensation structure?** (rate and bill impacts analysis)

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[2] In this study, the terms Distributed Energy Resource (DER) and Distributed Generation (DG) are used interchangeably to refer to technologies eligible to participate in New Hampshire's NEM program.
[3] Avoided costs represent reductions in cost as a result of marginal reductions in load.
[4] Alternatively, DERs may also increase utility costs. For example, they may necessitate utility system upgrades.
[5] Guidehouse. (2020). New Hampshire Locational Value of Distributed Generation Study. Available online: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF

1.1 – Study Context

The first DER NEM programs were established in New Hampshire many years ago. Today in the state, DER systems up to 1 MW in size (and up to 5 MW in size for "municipal host" facilities) are eligible to net meter, and participants are compensated in accordance with the New Hampshire alternative NEM tariff (NEM 2.0 tariff).[6,7] Since their inception, New Hampshire's NEM programs have experienced considerable year-over-year increases in DG deployment. As of December 2020, there were more than 10,000 systems enrolled in NEM programs with the state's utilities, equivalent to approximately 109 MW of total installed capacity.[8]

New Hampshire has experienced increased DER penetration in recent years, and it is anticipated that trend may continue. As net-metered DER penetration increases, changing impacts – both avoided costs and incurred costs – are expected for both utilities and ratepayers. This value stack assessment quantifies those impacts, considering changes to avoided and incurred costs resulting from future incremental additions of net-metered DERs in the state. For the purposes of this study, these avoided cost/cost categories are referred to as "value stack criteria."

The study was conducted on behalf of the New Hampshire Department of Energy. The New Hampshire alternative NEM tariff (NEM 2.0) was approved in a June 2017 order issued by the Public Utilities Commission (PUC).[9] The same order specified that a VDER study be conducted to assess the value of long-term avoided costs using marginal energy resource values and incorporating test criteria from standard energy efficiency benefit-cost analysis, a directive which shaped the VDER study methodology. The results of this study are expected to inform future NEM tariff development proceedings before the PUC.

1.2 – Study Scope

The study scope is defined by the following:

- **Study Period:** 2021-2035.
- **Geography:** The study is statewide, covering the three regulated electric utility service territories in New Hampshire: Public Service Company of New Hampshire d/b/a Eversource Energy

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[6] An outline of New Hampshire's current alternative "NEM 2.0" tariff, including how it is contrasted with the standard "NEM 1.0" tariff, is available online: https://www.puc.nh.gov/sustainable%20energy/Group%20Net%20Metering/PUC-SE-NEM-Tariff-2020.pdf.

[7] Systems installed prior to September 1, 2017 are compensated under the standard (or interim) net metering tariff (NEM 1.0) and are grandfathered until December 31, 2040.

[8] ISO-NE Distributed Generation Forecast Working Group. (2020). New Hampshire Update on State Distributed Generation Policy Drivers. Available online: https://www.iso-ne.com/static-assets/documents/2020/12/dgfwg_nh2020.pdf

[9] Order No. 26,029, issued in Docket DE 16-576 on June 23, 2017. Systems on the alternative NEM tariff are grandfathered until 2040 if a new rate goes into effect in the future.

(Eversource), Unitil Energy Systems, Inc. (Unitil), and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty (Liberty).

- **Distributed Generation System Types:** The DERs included in this study are limited to distributed generation (DG) technologies that are eligible for NEM in New Hampshire, specifically solar, solar paired with battery storage, and small hydro. The study includes distributed generation archetypes that are representative of average installations in the residential and commercial sectors. This study does not extend to other types of DERs.

- **Value Perspectives:** The study assesses the value of new net-metered DERs from the perspective of the utility system, participating customer-generators, non-participating utility customers, and average utility customers. Existing DER impacts are assumed to be accounted for in the market.

- **Value Proposition**: The study primarily focuses on the ability of net-metered DERs to generate value through load reductions, however direct participation in the ISO-NE markets is also considered as a sensitivity in the market resource value scenario. The study also includes levelized net present value customer installed costs; in the future, those costs could be used to evaluate how NEM crediting and compensation may impact reasonable opportunities to invest in DG and receive fair compensation for net electricity exports to the grid.

- **Data Sources**: The study aims to maintain consistency with energy efficiency cost-effectiveness evaluation practices, to the extent possible, by using standard benefit-cost criteria, tools and methodologies from the regional Avoided Energy Supply Costs (AESC) 2021 study.[10] Utility data requests and interviews, as well as other relevant sources, were used to assess value stack criteria that fell outside of the AESC study scope.

- **Sensitivities:** The study also assesses sensitivities to determine:

    a. The value of environmental externalities (while mitigating the potential for double-counting by excluding certain price-embedded environmental costs);

    b. Impacts of future high load growth on value stack criteria; and

    c. The value that net-metered DERs can achieve by participating directly as market resources rather than merely as passive load-reducing resources.

- **Model:** The study includes an accompanying interactive model, allowing users to assess the full suite of avoided cost value stack and sensitivity results.

[10] Synapse Energy Economics. (October 2021). Avoided Energy Supply Components in New England: 2021 Report – Non-embedded environmental compliance section. Available online: https://www.synapse-energy.com/project/aesc-2021-materials

1.3 – Study Limitations

The reader should keep in mind the following study limitations:

- In this study, net-metered DERs are treated as price takers, where the magnitude of their adoption has little or no impact on wholesale market prices. The Demand Reduction Induced Price Effect (DRIPE) is intended to evaluate the price-depressive effects on energy and capacity, however the potential price impacts of DERs on the value of other avoided cost components, such as Regional Network Service (RNS) and Local Network Service (LNS) transmission charges, Renewable Portfolio Standard (RPS), and environmental externalities, and others, have not been evaluated.
- The avoided cost values calculated in the VDER study are assumed to apply statewide. Actual avoided costs, however, are expected to vary within the state and may be subject to local grid and market conditions.
- Distribution capacity avoided costs include only avoided small-scale system-wide investments. Locational distribution capacity avoided costs are not considered in this study, but may be significant; potential avoided costs are locational as well as time-varying.11
- For some value stack criteria, such as distribution system operating expenses, avoided cost values were determined using historic investment relative to historic load growth, with the assumption that historic trends will be indicative of future costs. That may not be the case if the utility system experiences unprecedented DER growth or higher load growth in future years.
- In the high load growth scenarios, the equation to calculate marginal emissions for the environmental externalities sensitivity analysis was developed through a regression analysis between New Hampshire's hourly demand and the associated CO_2 and NOx emissions, and as a result the emissions factor is assumed to increase with increased demand. The equation does not capture changes in resource mix and market conditions that could result in lower emissions rates.
- Avoided costs are assessed from the perspective of in-state cost impacts, consistent with the approach used to assess benefits from energy efficiency activities in the state.
- As market conditions evolve, avoided cost values may change. If market conditions change significantly from those forecasted at the time of this study, the avoided cost values may be affected. The accompanying model can be used to assess how changes to avoided cost values would affect the estimated value of various DERs.

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[11] Guidehouse. (2020). New Hampshire Locational Value of Distributed Generation Study. Available online: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF

2 Methodology

2.1 – Methodology Overview

The VDER study methodology framework can be summarized by five high-level steps, outlined below:

1. Establish **Technology Neutral Value Stack** → 2. Develop **DER Production Profiles** → 3. Assess **DER Avoided Cost Value** → 4. Test **Avoided Cost Sensitivities** → 5. Assess **Rate and Bill Impacts**

First, technology-neutral avoided cost values are established (step 1). Next, DER production curves are developed for each resource type (step 2) and mapped against the technology-neutral avoided costs to calculate the avoided cost value of DERs by system type (step 3). Avoided cost values are also calculated under sensitivity cases, including consideration of environmental externalities, high load growth scenarios, and a market resource value scenario (step 4). Finally, the rate and bill impacts are assessed, determining how DER deployment and compensation will affect New Hampshire rates and customer bills (step 5).

The methodologies for each of these steps are described at a high-level in the sections that follow. Additional methodological detail is provided in the appendices.

2.2 – Technology Neutral Value Stack

2.2.1 – Base Value Stack Criteria

In keeping with the study goals of maintaining consistency with energy efficiency cost-effectiveness evaluation, avoided cost values from the AESC study (2021 edition) are used wherever possible.[12] For avoided cost criteria that are not included in the AESC study, relevant inputs were gathered through a combination of New Hampshire utility data requests, utility interviews, and literature reviews. Each value stack criterion falls into one of the following three groupings, categorized according to data availability and the evaluation methodology used:

- Evaluated using **AESC data, methods, and results**
- Evaluated using **quantitative methods unrelated to AESC**
- Evaluated using **qualitative review**

[12] AESC 2021 includes four counterfactual scenarios that estimate avoided costs under scenarios that include or exclude various demand-side resources. The purpose of these counterfactual scenarios is to calculate avoided cost values while either accounting for or excluding demand-side resources in a systematic fashion to understand the associated implications for avoided costs. For this study, AESC counterfactual 2 was selected, which does not include building electrification impacts. Building electrification impacts are included in the high load growth sensitivity, however.

The sections below describe each of the criteria at a high level, providing rationale as to why the criterion has value. Detailed methodologies and sources are included in Appendix C: Detailed Base Value Stack Methodologies.

Across all criteria, prices are adjusted to real 2021 dollars and $/kWh values are calculated for each hour of the study (8,760 hours per year, years 2021-2035).

2.2.1.1 – Energy

Evaluated using **AESC data, methods, and results**

Energy produced by net-metered DG reduces the amount of energy that New Hampshire utilities and load-serving entities must procure through the ISO-NE wholesale energy market, thereby reducing costs. Hourly Locational Marginal Prices (LMPs) specific to the New Hampshire zone reflect the displaced variable generation costs associated with the marginal resource(s) in the system and are thus considered to be an appropriate measure of the value of avoided energy in the state.

2.2.1.2 – Capacity

Evaluated using **AESC data, methods, and results**

Production by net-metered DERs that is coincident with the annual ISO-NE system peak reduces the amount that utilities and load-serving entities pay for capacity procurement in the ISO-NE market, thereby reducing in-state costs for New Hampshire utilities and Load Serving Entities (LSEs).[13] The avoided cost of capacity is determined by the ISO-NE Forward Capacity Market (FCM) and adjusted to reflect the variation between the Forward Capacity Auction (FCA) clearing price, which is established three years in advance of the time that capacity is procured, and the actual cost of capacity procured in the market.

2.2.1.3 – Ancillary Services and Load Obligation Charges

Evaluated using **AESC data, methods, and results**

Two assumptions underpin the valuation of this criteria element:

1. Any reduction in wholesale load would reduce ancillary service and load obligation charges that are assessed to New Hampshire utilities and LSEs;[14] and
2. Given challenges in accurately determining a price forecast and cost projections for these criteria, they can be proportionally pegged to wholesale energy prices for the purpose of this analysis.[15]

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[13] ISO-NE calculates capacity payment obligations for New Hampshire's distribution utilities (and all other load-serving entities in the ISO-NE market area), based on their relative contributions to the ISO-NE annual system peak load hour during the preceding year. If net-metered DG systems reduce utility load during the ISO-NE system peak hour, the capacity payment obligations assigned to New Hampshire's utilities and LSEs are reduced, resulting in in-state avoided costs.

[14] This approach is similar to how such charges are currently calculated for purposes of surplus net-metered generation payments in New Hampshire.

[15] Although ancillary services and load obligation charges are *not* always proportional to wholesale energy costs, there is a rationale for linking these for the purpose of this analysis. In ISO-NE, natural gas combustion turbines are typically the marginal energy resources and also typically provide ancillary services. It therefore follows that the price of ancillary services using those resources would be proportional to the price of providing energy using such resources.

As such, it is assumed that a reduction in wholesale load due to net-metered DER production will reduce the ancillary services and load obligation charges that are assessed to New Hampshire's utilities and LSEs, resulting in in-state avoided costs.

2.2.1.4 – RPS Compliance

Evaluated using **AESC data, methods, and results**

Energy produced by behind-the-meter DERs reduces the utility's retail energy sales. Because RPS obligations are proportional to energy supplied (i.e., retail sales), increased DER output results in decreased RPS compliance costs.[16] This avoided cost value is only applied to the portion of energy that is generated by DERs and consumed behind-the-meter; it excludes the portion of energy output that is exported back to the grid.

2.2.1.5 – Transmission Charges

Evaluated using **quantitative methods unrelated to AESC**

ISO-NE collects Regional Network Service (RNS) and Local Network Service (LNS) charges to cover the costs of upgrading and maintaining regional bulk transmission system infrastructure and certain lower voltage local facilities. Utility RNS and LNS charges are assessed monthly based on the coincidence of utility system monthly peaks with the monthly ISO-NE system peak. Production by net-metered DG resources that is coincident with the monthly ISO-NE system peak reduces the amount that utilities pay in RNS and LNS transmission charges, thereby reducing in-state costs.

2.2.1.6 – Transmission Capacity

Evaluated using **qualitative review**

There may be some transmission capacity upgrades that are not deemed to be either Pool Transmission Facilities (PTF) covered by RNS charges, or more local transmission facilities covered by LNS charges, as described in the 'Transmission Charges' criteria summarized above. It is expected that those other upgrades would be driven by demand during system peak periods. Net-metered DERs that reduce load during those peak windows may be able to avoid or defer such upgrades. Because this criterion is assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

[16] The RPS requires electricity providers to serve a minimum percentage of their retail load using renewable energy. Across ISO-NE, the requirements vary by state. In New Hampshire, the total percentage of renewables required increases each year until 2025 according to a pre-defined schedule. The New Hampshire RPS statute includes minimum requirements by four renewable energy classes (with one specific additional carveout): new renewable energy (class I), useful thermal energy (class I thermal), new solar (class II), existing biomass/methane (class III), and existing small hydroelectric (class IV). If electricity providers are not able to meet the RPS requirements by acquiring renewable energy certificates, they must pay alternative compliance payments ($/MWh) into the state renewable energy fund.

2.2.1.7 – Distribution Capacity

Evaluated using **quantitative methods unrelated to AESC**

Energy produced by net-metered DG has the potential to avoid or defer distribution capacity upgrade costs if it reduces load at hours associated with reliability concerns (i.e., during peak hours that would otherwise drive investments in distribution system upgrades). In connection with the Locational Value of Distributed Generation (LVDG) study,[17] New Hampshire's utilities estimated the capital investments that would be required at various substations or circuits as a result of capacity deficiencies based on relevant planning criteria. Beyond those upgrades required to address capacity deficiencies, some investments are also expected to be required to address non-capacity upgrades (e.g., those related to reliability or performance issues), which the LVDG study did not address. Because the capacity-related deficiencies and the related potential avoided costs, reviewed in the LVDG study are highly locational, those costs are not considered in this study, which reviews system-wide avoided costs only.

2.2.1.8 – Distribution System Operating Expenses

Evaluated using **quantitative methods unrelated to AESC**

Net-metered DG has the potential to increase or decrease distribution-level system operating costs incurred by the utilities. For the purpose of the study, this criterion is considered to be an avoided cost, with any incremental costs associated with distribution system operating expenses covered under the 'T&D system upgrades' criterion. As such, this criterion represents reductions or deferrals of distribution system operating expenses, as a result of equipment life extension, lower maintenance costs, lower labor costs, and other such expense reductions or deferrals.

2.2.1.9 – Transmission Line Losses

Evaluated using **AESC data, methods, and results**

Energy produced by net-metered DG resources reduces the energy that would otherwise move through the transmission network. Any surplus energy that is exported by such resources to the distribution system is assumed to be contained within the distribution network; no transmission backflow associated with such surplus energy is assumed to occur. As such, the avoided transmission line losses apply to the *total* energy produced by the DG resource. It should be noted that this avoided cost criterion is calculated as a *cumulative* value, incorporating line loss values from the energy, capacity, and DRIPE avoided cost criteria. Any value from avoiding transmission line losses that is typically attributed to those other criteria has been removed to avoid double-counting and is included in this criterion instead.

[17] Guidehouse Inc. (2020). New Hampshire Locational Value of Distributed Generation Study. Accessible online at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF#:~:text=The%20New%20Hampshire%20Public%20Utilities%20Commission%20%28the%20Commission%29,metering%20docket.%20In%20its%20February%202019%20order%2C%201

2.2.1.10 – Distribution System Line Losses

Evaluated using **AESC data, methods, and results**

Energy produced by net-metered DG reduces the energy that would otherwise move through the utility distribution system. Any surplus energy that is exported by such resources to the distribution grid is assumed to stay within the distribution system. As such, avoided distribution line losses apply *only* to the portion of the energy produced by the DG resource that is consumed behind-the-meter. As with the transmission line losses criterion, this avoided cost is calculated as a *cumulative* value, incorporating line loss values from all relevant energy, capacity, RPS compliance, and DRIPE avoided cost criteria. Any value from avoiding distribution line losses that is typically attributed to those other criteria has been removed to avoid double-counting and is included in this criterion instead.

2.2.1.11 – Wholesale Market Price Suppression

Evaluated using **AESC data, methods, and results**

Electricity generated by DG at customers' sites reduces the overall energy and capacity procured through the wholesale market. The reduced demand results in lower market clearing prices, and this price suppression benefit - DRIPE - ultimately may be passed on to market participants and their customers. For this analysis, we considered the direct price suppression benefits that result from reduced energy (Energy DRIPE), reduced capacity (Capacity DRIPE), and the indirect price suppression benefits that result from reduced electricity demand on gas prices, which in turn reduces electricity prices (Electric-to-Gas-to-Electric cross-DRIPE).

2.2.1.12 – Hedging/Wholesale Risk Premium

Evaluated using **AESC data, methods, and results**

Retail avoided costs include a risk premium which increases the price of retail electricity beyond the price of wholesale electricity. This premium accounts for the risk inherent in establishing contract prices in advance of supply delivery; there is uncertainty in the final market prices that will be charged to the supplier, and there is uncertainty in the final electricity demand of buyers. Load reductions from net-metered DERs reduce wholesale energy and capacity obligations, and therefore load-serving entities' (such as the suppliers of default service energy to New Hampshire electric utilities) costs to mitigate those market risks.

2.2.1.13 – Distribution Utility Administrative Costs

Evaluated using **quantitative methods unrelated to AESC**

An increase in installed DG resources may increase associated utility administrative costs. Examples include those costs associated with NEM program administration, metering, billing, collections, evaluations, and any unreimbursed interconnection assessments. The utilities' related administration costs, including labor, materials, and outside services that are in excess of the administration costs for a typical non-DG customer, and are not covered by the customers themselves, are included in this criterion.

2.2.1.14 – Transmission and Distribution System Upgrades

This criterion is an incurred cost category rather than an avoided cost category. It encompasses all costs related to transmission and distribution system upgrades that are driven by the addition of net-metered DG to the grid. Because this criterion was assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

Evaluated using **qualitative review**

2.2.1.15 – Distribution Grid Support Services

This criterion may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs for distribution system support services required as net-metered DG penetration increases. Because this criterion was assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

Evaluated using **qualitative review**

2.2.1.16 – Resilience Services

In this study, resilience services are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[18] Resiliency has the potential to generate significant value, although this value is expected to be highly context-specific. Because this criterion was assessed using a qualitative review, it is not quantified as part of the value stack; instead, qualitative insights are included in the results section.

Evaluated using **qualitative review**

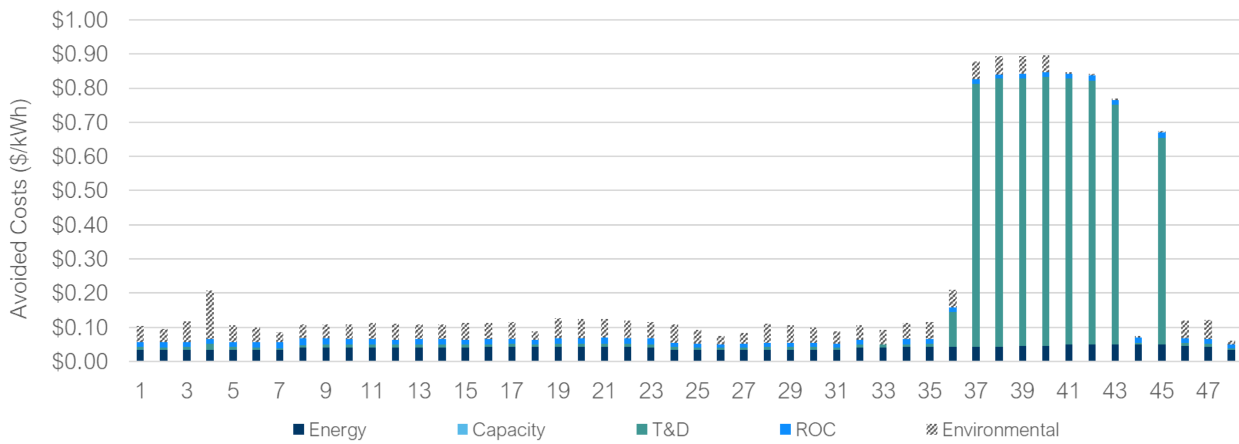
2.2.2 – Example Value Stack

The avoided cost value criteria are combined to develop a technology-neutral value stack which quantifies avoided cost values during each hour of the study period. Figure 6 below illustrates this value stack for a hypothetical 48-hour period. These days include a number of estimated peak demand hours on the New Hampshire distribution grid, demonstrating how avoided cost values vary according to system conditions. For ease of presentation, the avoided cost criteria are grouped into four categories: energy, capacity, transmission and distribution (T&D), and rest of criteria (ROC).[19] The environmental externalities sensitivity is also shown.

[18] This definition was sourced from the US DOE Office of Energy Efficiency and Renewable Energy, available online: https://www.energy.gov/eere/femp/distributed-energy-resources-resilience

[19] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

Figure 6. Technology-Neutral Value Stack (2021$)



A subset of hours starting at hour 36 includes high avoided cost values in the T&D category, which coincide with periods of high system demand. The hourly avoided costs for these criteria are assumed to be driven by system peaks, and therefore increase in value when demand is high and decrease when demand is low.

2.2.3 – Customer Installed Costs

Customer installed costs are calculated separately from the value stack. Costs are calculated on a net present value basis for each system type, considering upfront and operational costs as well as available incentives. The costs are levelized by total energy production over the system's lifetime. In the future, those estimated costs could be used to assess the cost-effectiveness of DER systems from the perspective of customer-generators with net-metered DG systems. Customer installed costs are described in more detail in Section 3.3 below.

2.3 – DER Production Profiles

To assess the value of DERs, illustrative net-metered DG production curves are required. The study characterizes eight archetypal DG resources for the assessment, aiming to represent the diversity of systems that participate in statewide NEM programs:

- **Residential south-facing solar** (7.8 kW DC, 6.5 kW AC): The system size represents the average residential solar PV system currently installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape. [20]

- **Residential west-facing solar** (7.8 kW DC, 6.5 kW AC): The system size represents the average residential solar PV system installed in Eversource's territory. To date, customer-generators in New Hampshire have been incentivized to maximize volumetric energy credits by installing south-facing systems. Given limited New Hampshire-specific data for west-facing

[20] ISO New England. (2022). Load Forecast. Available online: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Hourly%20Behind-the-Meter%20Photovoltaic%20Data

production profiles, the normalized solar production profile from PV Watts informed the production profile shape for the west-facing system. [20]

- **Commercial south-facing solar** (36 kW DC, 30 kW AC): The system size represents the average commercial solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape.[20]

- **Commercial west-facing solar** (36 kW DC, 30 kW AC): The system size represents the average commercial solar PV system installed in Eversource's territory. To date, customer-generators in New Hampshire have been incentivized to maximize volumetric energy credits by installing south-facing systems. Given limited New Hampshire-specific data for west-facing production profiles, the normalized solar production profile from PV Watts informed the production profile shape for the west-facing system.[21]

- **Residential south-facing solar paired with storage** (7.8 kW DC, 6.5 kW AC solar PV system, 4-hour duration 10 kWh/2.5kW storage system): The system size represents the average residential solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape.[20] The storage system size and duration represent a typical residential storage system. The storage system charging hours were selected to occur during high solar production and relatively lower avoided cost values (HE11 to HE14) while discharging hours were selected to occur during periods of higher avoided cost value (HE18 to HE21). The charging and discharging windows remained fixed throughout the study period; a dynamic optimization schedule for charging and discharging was out-of-scope for this study.

- **Commercial south-facing solar paired with storage** (36 kW DC, 30 kW AC solar PV system, 4-hour duration 40 kWh/10kW storage system): The system size represents the average commercial solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape.[20] The storage system size and duration represent a typical small commercial storage system. The storage system charging hours were selected to occur during high solar production and relatively lower avoided cost values (HE11 to HE14) while discharging hours were selected to occur during periods of higher avoided cost value (HE18 to HE21). The charging and discharging windows remained fixed throughout the study period; a dynamic optimization schedule for charging and discharging was out-of-scope for this study.

- **Large Group Host Commercial Solar** (195 kW DC, 162 kW AC single-axis tracking): The system size represents the average large general commercial solar PV system installed in Eversource's territory. The normalized solar production profile published by ISO-NE informed the production profile shape. [22]

- **Micro hydro** (3 MW): Using internal tools, Dunsky developed an 8,760 hourly load profile for a small hydro facility that considered the month-to-month variation in generation for a small run-

[21] NREL. (2022). PVWatts Calculator. Available online: https://pvwatts.nrel.gov/
[22] ISO New England. (2022). Load Forecast. Available online: https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/?document-type=Hourly%20Behind-the-Meter%20Photovoltaic%20Data

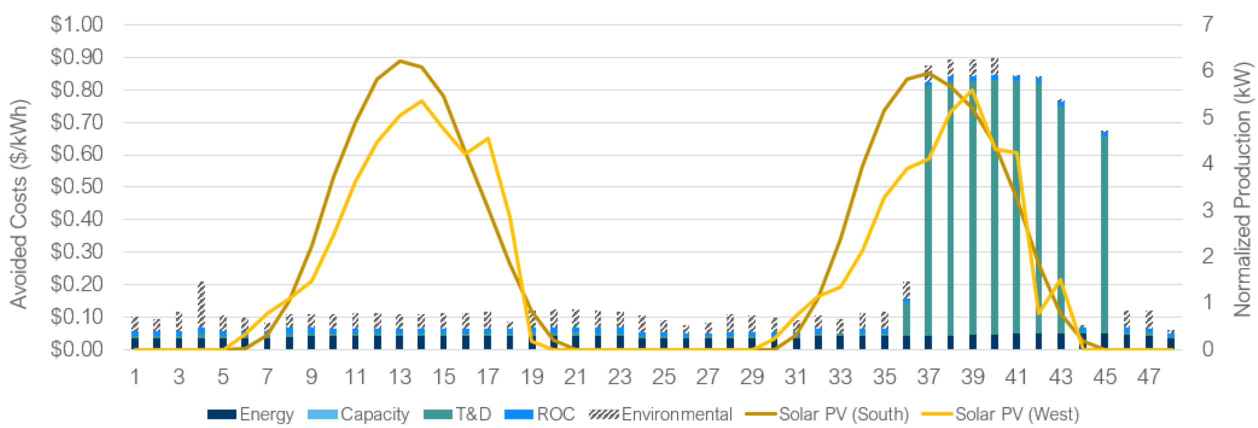
of-river hydro facility located in New Hampshire. The month-to-month variation in hydro generation was developed using New Hampshire-specific hydro data from the U.S. DOE EIA.[23] Because hydro facilities vary in size and capacity factors, for modelling purposes, we assumed a small hydro facility of 3 MW.

To minimize day to day variations, the production profile was averaged by hour for each month for all solar systems. Annual 8,760 production profiles for each system type are included in Appendix Section A: DER Production Profiles.

2.4 – DER Avoided Cost Value

Figure 7 below shows how production of two residential systems, one south-facing and one west-facing, varies across the same hypothetical 48-hour period, and how that production maps to the illustrative hourly avoided cost stack presented in section 2.2.2 Example Value Stack.

Figure 7. Technology-Neutral Value Stack and Sample Solar Production Profile (2021$)



To assess DER value, the production curves for each DG type (in kW) are combined with the technology-neutral value stack for each hour (in $/kW) to assess technology-specific hourly avoided costs (in $/kWh). To assess average annual avoided cost values, the technology-specific avoided costs are summed across all hours in each year and then divided by the total annual DG production to calculate an average annual avoided cost value. A similar process is used to determine average seasonal avoided cost values – the total avoided costs are summed across all months in a season, then divided by total production during that season.

2.5 – Avoided Cost Sensitivities

Sensitivities are included in the study to test how the avoided cost value associated with DERs may be expected to change according to the degree to which externalities are considered (Environmental Externalities Sensitivity), should future load growth be higher-than-projected (High Load Growth

[23] EIA. (2022). New Hampshire Electricity Dashboard. Available online: https://www.eia.gov/beta/states/states/nh/data/dashboard/electricity

Scenarios), or should aggregated DERs participate in the ISO-NE market (Market Resource Value Scenario). The methodologies used to assess these sensitivities are briefly described in the following sections.

2.5.1 – Environmental Externalities Sensitivity

Fossil fuel combustion generates greenhouse gas (GHG) emissions and other air pollutants, including carbon dioxide (CO_2) emissions, sulfur dioxide (SO_2) emissions, nitrogen oxide (NO_x) emissions, and particulate matter. Methane emissions are also released during natural gas production, transportation, and use. A portion of the environmental costs associated with CO_2 emissions are already embedded in wholesale electric energy prices. However, there are additional societal costs associated with CO_2 and other emissions that are not embedded in energy prices. Where possible, the environmental externalities sensitivity assesses the avoided cost value of each air pollutant type considering only non-embedded costs. The approach taken for each air pollutant type is described below:

- **CO_2 emissions:** The AESC wholesale energy price forecasts include the costs of compliance with the Regional Greenhouse Gas Initiative (RGGI). For this analysis, the full social cost of CO_2 emissions (net of RGGI compliance costs to avoid double-counting) is included in the environmental externalities value.[24]

- **SO_2 emissions:** The AESC assumes that all coal-fired generation – the primary source of SO_2 emissions from electricity generation – is taken offline by 2025. For this analysis, the value of SO_2 emissions is assumed to be minimal, and therefore is not included in the environmental externalities value.

- **NO_x emissions:** The AESC wholesale energy forecasts do not include any costs associated with NO_x emissions. For this analysis, the full social cost of NO_x emissions (AESC 2021) is included in the environmental externalities value.[25]

- **Particulate matter:** The AESC wholesale energy price forecasts do not include any costs associated with particulate matter. When considering energy generation, particulate matter is primarily produced by coal and biomass combustion. Because coal-fired generation is assumed to be taken offline by 2025, the impacts of particulate matter from coal combustion are not included in the environmental externalities value. Although biomass remains a generation source throughout the study period, it provides baseload power rather than marginal generation. Because biomass facilities do not generate electricity on the margin, reductions in biomass-related particulate matter emissions are not expected as a result of net-metered DER load reductions. The impacts of particulate matter are therefore also excluded from the environmental externalities value.

[24] Synapse Energy Economics. (2021). AESC 2021 Supplemental Study: Update to Social Cost of Carbon Recommendation. Available online: https://www.synapse-energy.com/sites/default/files/AESC_2021_Supplemental_Study-Update_to_Social%20Cost_of_Carbon_Recommendation.pdf
[25] Synapse Energy Economics. (2021). Avoided Energy Supply Components in New England: 2021 Report – Non-embedded environmental compliance. Available online: https://www.synapse-energy.com/project/aesc-2021-materials

- **Methane:** Although the societal costs of methane are considerable on a per ton basis, methane emissions are challenging to quantify and forecast as they primarily occur upstream from power generation during the production, processing, storage, transmission, and distribution of natural gas and oil, and have not been thoroughly monitored or studied. In addition, the U.S. government is taking steps to substantially reduce upstream methane emissions through a proposed rule applicable to new and existing facilities, which targets a 74% reduction in methane emissions from oil and gas production from 2005 levels by 2030.[26] Given the challenges inherent in developing methane emissions forecasts for ISO-NE, and in view of federal government proposals to reduce methane emissions during the study period, methane is not included in the environmental externalities value.

Environmental externalities represent benefits/costs that are external to utility system valuation and therefore are not currently included in NEM tariff design. There is value in estimating actual non-embedded environmental externality benefits associated with net-metered DG production, however, and as such those benefits are included in the study as a sensitivity.

2.5.2 – High Load Growth Scenarios

The value that net-metered DG resources bring to customers, utilities, and the grid will vary to some degree depending on the magnitude and characteristics of future load growth. Future electricity load growth will depend, in large part, on the extent of heating electrification in buildings and transportation electrification, each of which will exert an influence on the timing and extent of seasonal electric system peaks. The inherent uncertainty around the adoption of these technologies translates into uncertainty around load growth on the system. The high load growth scenarios (HLGS) analysis considers several scenarios for increased load growth – each varying with respect to building or transportation electrification adoption – to investigate the impact of loads on the value of net-metered DERs. The detailed HLGS methodology is included in Appendix Section D: High Load Growth Scenarios Methodology.

2.5.3 – Market Resource Value Scenario

Apart from the avoided cost benefits achieved through passive load reduction, aggregated DG resources may generate monetizable value by participating directly in wholesale power markets. The market resource value scenario (MRVS) sensitivity quantifies the value of net-metered DG resources participating directly in relevant wholesale power markets for those criteria where there is a readily discernible market value or a value different from those established in the load reduction estimate, notably capacity. DG resources could theoretically also provide ancillary services to the market; however, provision of those services typically requires that resources do not participate in the energy market, so DER provision of ancillary services is expected to be uneconomic.[27] Accordingly, ancillary services market values are not

[26] US EPA. (2021). News Release: U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health. Available online: https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health
[27] As one example, for a solar resource to provide operating reserves, it requires "headroom," which would allow it to increase output in response to a generator activation instruction by ISO-NE. To provide such headroom, the generator would need to be dispatched down, resulting in an opportunity cost for the operator.

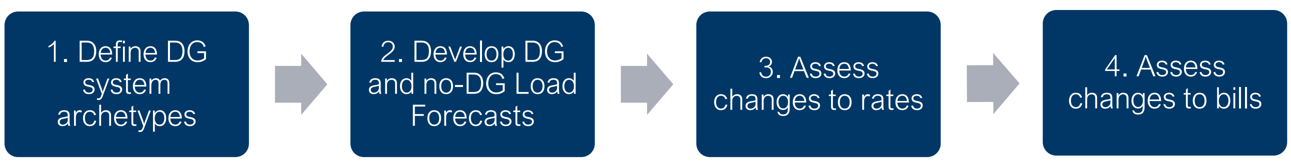
quantified as part of the MRVS. The detailed MRVS methodology is included in Appendix E: Market Resource Value Scenario Methodology.

2.6 – Rate and Bill Impacts

The Rate and Bill Impact Assessment provides high-level insight into the impact of DG deployment in New Hampshire on ratepayers, considering the benefits received and the costs incurred by the utilities as a result of incremental DG additions (which, for the purpose of this analysis, are limited to solar PV systems), and considering how those values are passed on to ratepayers.

The assessment aims to provide a future-looking estimate of the direction and magnitude of the rate and bill impacts of DG deployment and to identify any potential cost-shifting between customers with and without DG. It is not intended to represent an exact projection of future electricity rates and utility cost recovery. Instead, it serves as a future-looking approximation of the impacts on ratepayers attributable to DG deployment in New Hampshire.

The rate and bill impacts methodology can be summarized by four high-level steps, outlined below:



2.6.1 – Define DG System Archetypes

For this analysis, solar PV system archetypes are defined for each utility (Eversource, Unitil, and Liberty) and for representative rate classes (residential, small commercial, and large commercial). System archetypes are defined by the PV system size as well as the percentage of energy produced that is consumed behind-the-meter based on the load patterns of a typical customer in that rate class.

The assumptions used for each are calculated using *utility-specific* interconnection data, resulting in average system size assumptions that vary by utility. The archetypes used for this analysis are summarized in Table 1 below.

Table 1. Rate and Bill Impacts Analysis Solar PV Archetype by Rate Class and Utility

Rate Class	Eversource	Unitil	Liberty	% Self-Consumed
Residential	7.6	12.2	10.1	72% (Monthly Netting)
Small Commercial	24.5	43.0	41.3	65% (Monthly Netting)
Large Commercial	329.2	47.2	209.6	99% (Hourly Netting)

2.6.2 – Develop DG and no-DG Load Forecasts

To assess the impacts of DG, a 'no-DG' scenario is required to serve as a baseline. The 'no-DG' scenario is a hypothetical illustration of the system outlook in the absence of projected *new* DG capacity additions and is used as a comparison to evaluate the impact attributable to future incremental DG deployment. The no-DG load forecast is developed by multiplying the forecast of customer counts for each rate class by the expected electricity sales.

The DG scenario reflects the impacts associated with future DG deployment forecasted by ISO-NE, which assumes that 140 MW of additional DG (predominantly solar PV) will be deployed in New Hampshire between 2021 and 2030; that amount is above and beyond the existing 120 MW already deployed today. Using insights from historical utility interconnection data, we estimated the expected distribution of future DG deployment among the three utilities and three rate classes.

Using the forecasted level of DG uptake, our team then estimated the corresponding hourly energy production and used that to estimate the expected impacts of DG deployment on annual energy consumption (GWh) and peak load (MW) for each utility and rate class. The impacts were calculated at the customer meter/distribution system, transmission system, and bulk system, using assumptions on system losses as well as the peak coincidence factor between the different levels.

Beyond the utility/rate class level load forecast, our team computed the average monthly electricity consumption (i.e., kWh consumed per month), as well as the annual non-coincident peak demand (i.e., kW peak demand used for the purpose of demand charges), for each of the three archetype rate classes across the three utilities for three representative customer types:

- **Typical DG customer:** a customer assumed to install the defined archetype DG system and experiencing a corresponding reduction in the customer's energy consumption and peak demand.
- **Typical non-DG Customer:** assumed to have the same consumption profile as the average utility customer in the no-DG scenario.[28]
- **Average utility customer:** computed as the total consumption divided by the number of customers across each rate class and utility.

[28] The consumption profile of all three customer types is assumed to be the same in the hypothetical no-DG scenario, equivalent to the energy consumption and peak demand of the average customer in that rate class.

2.6.3 – Assess Changes to Rates

The future deployment of DG is expected to create upward pressure on rates (due to lost utility revenues and program cost recovery) and downward pressure on rates (due to avoided utility costs).[29, 30] Additionally, rates are also impacted by reduced system throughput. The figure below highlights the theoretical framework that was used to assess the rate impacts of DG.[31]

Figure 8. Theoretical Framework Used to Assess the Rate Impacts of DG

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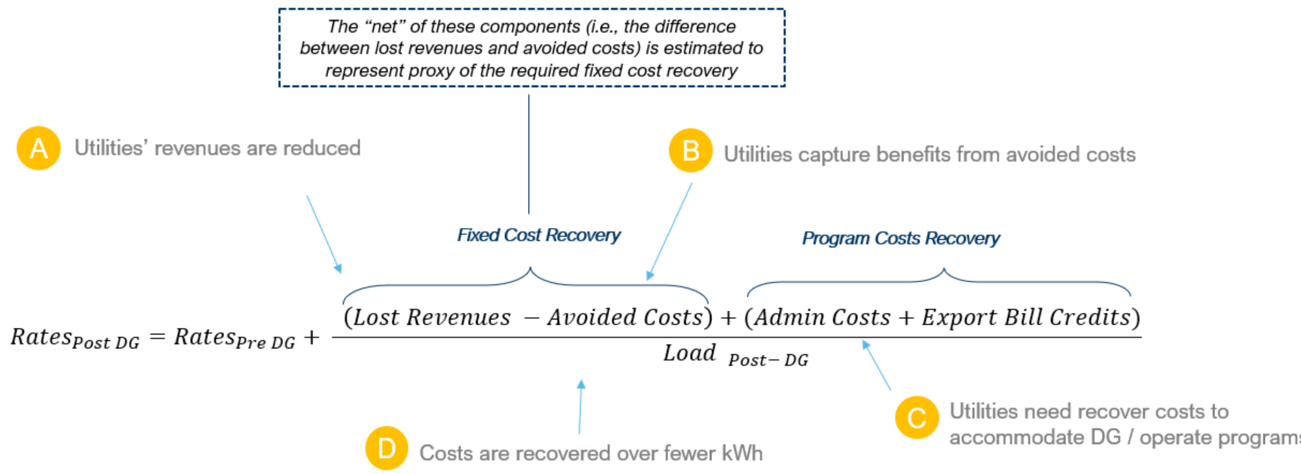

Specifically, the framework captures several key impacts of DG deployment on rates[32]:

A. Lost utility revenues due to reductions in electricity consumption.

B. Avoided costs, as indicated and quantified by the Value Stack assessment.

C. Program administration[33] and system costs, including compensation for net DG exports, incurred by utilities to accommodate DG.

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[29] Utility revenues are reduced because of reduced retail sales. These retail sales reductions are equivalent to the energy production by DG systems that is consumed behind-the-meter. Reduced retail sales create upward pressure on rates by increasing the share of utility fixed costs that must be covered by each unit of energy that is sold. Program costs refer to the costs required to administer DG-specific programs and compensate for exports. Utilities must recover the costs of running programs through rates. Again, as retail sales volumes are reduced, the share of program costs that must be covered by each unit of energy sold must be increased.

[30] Utilities also realize value as retail sales are reduced, avoiding the costs that would have been required to serve loads if they were not being served by behind-the-meter DG.

[31] This approach is largely in-line with that applied to evaluate the Rate and Bill Impacts of Energy Efficiency Programs in New Hampshire.

[32] The results of the rate impact assessment are based on the relative changes in the volumetric portion of the rates post-DG. The fixed charges and non-bypassable charges are assumed to be unchanged in the post-DG scenario.

[33] The assumed program administration costs include the costs for FTE (Labor), Engineering, Management, IT Support, Metering, and Installation. The administration cost projections were based on the forecasted number of installations across the three rate classes for each utility.

D. System costs that are recovered over lower energy sales.

The rate at which exported DG electricity output is compensated impacts rates for all utility customers. To illustrate the impacts of different potential DG program designs on ratepayers, changes to rates were assessed under two scenarios for DG compensation:

1. **NEM Tariff Scenario:** Assumes DG exports are compensated at a rate that is in alignment with current NEM compensation rates in the state.[34]
2. **Avoided Cost Value Stack (ACV) Tariff Scenario**: Assumes that DG exports are compensated at an avoided cost rate that is in alignment with the calculated value stack assessment.[35]

DG compensation impacts rates by changing the 'export bill credits' portion of the program cost recovery value (item C above). All other factors remain constant between the two scenarios.

2.6.4 – Assess Changes to Bills

Simply considering rates does not tell the whole story. Analysis of effects on customer bills, which are calculated using volumetric rates ($/kWh and $/kW) and consumption (kWh and kW peak), as well as fixed charges, provides a better indication of the overall impact on customers.

Representative monthly bills were computed for each of the utility/rate class permutations under the no-DG scenarios. Bills were then recalculated for each of the three representative customer groups described above (i.e., typical DG, typical non-DG customer, and average utility customer) under the assumed level of future DG deployment. Evaluating changes in bills of customers with DG and those without DG provides insights into the degree of cost-shifting between customer groups (i.e., the degree to which non-DG customers will see bill increases as a result of rate impacts from DG installations). Additionally, the estimated impacts on monthly bill for the average utility customer pre- and post-DG highlight the extent to which utility customers on average are better or worse off as a result of future DG uptake.

Changes to bills are assessed under two scenarios: the NEM scenario and the ACV scenario described above. The results are largely focused on presenting the average per cent increase/decrease in customers' monthly bills attributable to DG over the period 2021 to 2035 for each of the typical customer archetypes to indicate the long-term impacts of DG on utility customers.

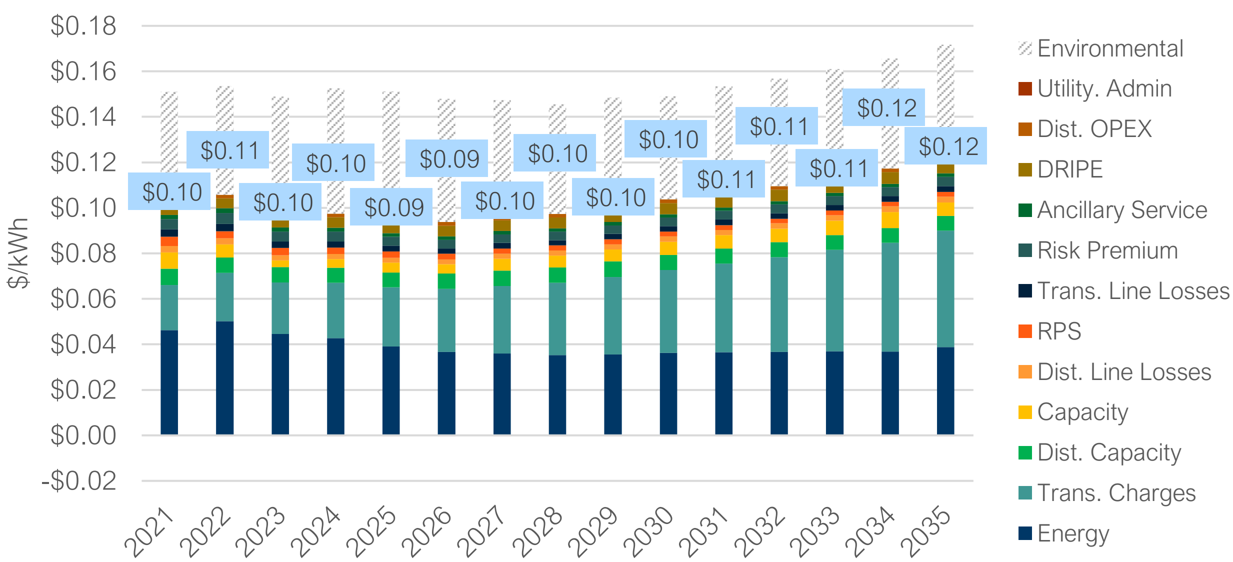
[34] The current alternative NEM tariff structure compensates systems under 100 kW at 100% of the generation and transmission rate components and 25% of the distribution rate component through monetary bill credits for monthly net exports. For systems over 100 kW, the export bill credit is equivalent to 100% of the generation rate component based on hourly net exports over the billing month.
[35] The analysis **does not** consider the impact that the transition to an Avoided Cost Value Stack compensation model would have on DG economics and deployment trends in New Hampshire (i.e., the same level of future DG deployment is assumed to occur under both scenarios).

3 Results

3.1 – Technology-Neutral Value Stack

The technology-neutral value stack quantifies the total avoided cost value during each hour of the study period. These hourly values can be averaged across each study year to generate average annual avoided costs, as shown in Figure 9 below.

Figure 9. Average Annual Technology-Neutral Value Stack (2021$)[a]



a. Totals shown are net values and exclude the value of environmental externalities

On an average annual basis, the technology-neutral avoided cost value stack ranges from $0.09/kWh to $0.12/kWh, excluding environmental externalities. Energy and transmission charges are the largest two value stack criteria in each study year, collectively representing between 65% and 74% of the total value. Initially, energy represents a larger share of the value stack. However, the avoided cost value of energy generally decreases over the study period as a result of 1) study-specific assumptions, and 2) AESC forecast trends:

1) In the first five years of the study, the energy avoided costs included in this study are higher than the AESC avoided cost forecast to account for increases in natural gas prices since the AESC was published.[36]
2) The value of energy declines over time in the AESC forecast as lower-cost resources increasingly participate in the market, such as offshore wind and solar.

Meanwhile, transmission charges avoided costs are forecasted to increase over time. For the initial study years, the transmission charge forecast trend was sourced from near-term (2021-2024) projections. Given limited insight into how these projections may vary post-2024, this near-term trend

[36] Energy prices have continued to increase following the analysis phase of the study. The study represents a snapshot in time, and there is a high degree of uncertainty around how prices can be expected to move in the future.

was extrapolated over the study period. Additional insights into this calculation are included in Appendix Section C.5: Transmission Charges.
Each of the remaining value stack criteria individually represents, at most, 7% of the value in any given year. Utility administration is the only value stack criteria with an average negative value. This represents the additional utility administrative costs of connecting and maintaining customer-generator DG installations over-and-above standard customer administrative costs.

Environmental externalities, which account for the social cost of carbon (net of carbon costs already embedded in wholesale energy prices) and the social cost of nitrogen oxide, would increase the value stack by between 41% and 59%, varying by year. Changes in the value of environmental externalities decline over time as the generating resource mix on the ISO-NE system is projected to increasingly include lower-emitting resources. Specifically, the AESC assumes that all coal-fired generating resources in ISO-NE are retired by 2025, and that some gas and oil generating units also are retired during the study period.

Annual averages are provided above for each of the criteria, however the values can vary considerably from hour to hour within a given year. Table 2 below includes the average annual values alongside the minimum and maximum hourly values for each of the criteria in 2021 and in 2035. These values are also provided for years 2025 and 2030 in Appendix Section B: Results Tables.

Table 2. Average Annual, Minimum Hourly, and Maximum Hourly Technology-Neutral Value Stack for 2021 and 2035 (2021$)

Criteria	2021			2035		
	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)
Energy	$0.046	$0.030	$0.082	$0.039	($0.008)	$0.159
Transmission Charges	$0.020	$0.000	$14.945	$0.051	$0.000	$38.407
Distribution Capacity	$0.007	$0.000	$0.667	$0.006	$0.000	$0.602
Capacity	$0.007	$0.000	$63.000	$0.006	$0.000	$52.000
Distribution Line Losses	$0.003	$0.000	$7.674	$0.002	($0.000)	$5.873
RPS	$0.004	$0.004	$0.004	$0.002	$0.002	$0.002
Transmission Line Losses	$0.003	$0.000	$4.474	$0.003	($0.000)	$3.424
Risk Premium	$0.005	$0.001	$1.151	$0.004	($0.001)	$0.726
Ancillary Service	$0.002	$0.001	$0.005	$0.002	($0.001)	$0.009
DRIPE	$0.004	$0.001	$4.954	$0.005	($0.001)	$8.541
Distribution OPEX	$0.002	$0.000	$0.149	$0.002	$0.000	$0.149
Utility Admin	($0.000)	($0.002)	$0.000	($0.000)	($0.002)	$0.000

For some criteria, the average annual value is considerably different from the maximum value in a given hour. In the most extreme case – the capacity criteria – value is only assigned to a single hour of the year, the annual ISO-NE system peak hour. The capacity payment obligations assigned to New Hampshire's utilities and load-serving entities are calculated according to the contribution of their customers to peak load during that single hour; production at any other hour will not affect capacity payment obligations, and therefore has zero capacity value. This results in a large difference between the average annual capacity value and the maximum hourly value. As other examples, the distribution capacity, transmission line loss, and distribution line loss criteria avoided costs are assumed to be driven by load reductions during peak hours on New Hampshire distribution systems. The annual value of each of those components is spread out over the top 100 peak distribution system hours, while the remaining 8,660 hours in each year have zero value, again driving considerable differences between the average annual value and the maximum hourly value.

The average annual value achieved by a particular DER (on a $/kWh basis) may be higher or lower than the average annual technology-neutral value stack value, depending on the specific DER production characteristics. DER-specific avoided cost values are influenced by the degree to which its electricity production coincides with hours of high avoided cost value and not with hours with zero avoided cost value. The avoided cost value achieved by a number of illustrative DER systems is presented in the sections that follow.

3.2 – Value Generated by DERs

The avoided cost value that net-metered DERs provide to the electricity system is assessed by considering DER production profiles in combination with the hourly value stack, as described in the DER Avoided Cost Value section above. The VDER model that accompanies this report allows users to produce the value stack that can be achieved by common DER technologies in New Hampshire. This tool is used to analyze the DER system types described in the "DER Production Profiles" section of this report, calculating the benefits that each provides to the electric system and – if reflected in rates – to customer-generators over the 2021 to 2035 period. The results show the degree to which load reductions from DERs can generate avoided cost value for the electric system, and how that value can be expected to vary over time as a result of changing system conditions.[37]

This study does not address all DERs, but rather focuses on a subset of those resources that are eligible for NEM in New Hampshire. The following sections illustrate key trends for sample DER system types that are generally representative of the most commonly-installed configurations: residential and commercial solar PV, residential and commercial solar PV paired with storage, large group host commercial solar PV, and micro hydro generation.

The results provided in this section are illustrative. Because the values presented below are calculated using specific sample system types, they should not be applied to other system types. The model that accompanies this report allows users to generate results specific to other system types using a custom production profile.

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[37] Although avoided costs also vary by location, the scope of this study only considers statewide averages. A separate Locational Value of Distributed Generation Study was conducted and the results of that study are available online: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF.

3.2.1 – Residential and Commercial Solar PV

Avoided cost values are modeled for south- and west-facing solar PV arrays for the residential and commercial sectors. Figure 10 and Figure 11 below show the calculated value of the south- and west-facing residential systems for several years during the study period. Detailed results tables showing the average annual value of each of the criteria in each study year are included in Appendix Section B: Results Tables. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

Figure 10. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 (2021$)[a]

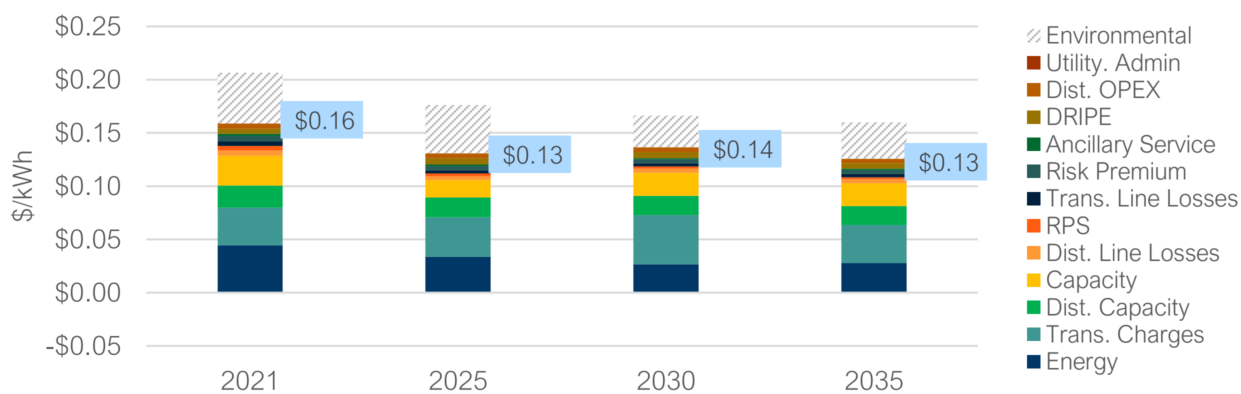
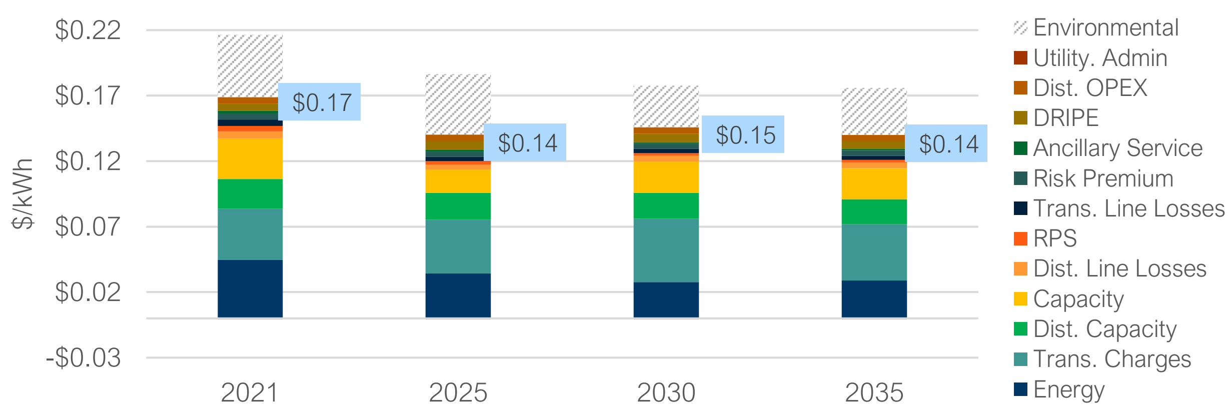


Figure 11. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 (2021$) [a]



a. Totals shown are net values and exclude the value of environmental externalities

Throughout the study period, residential west-facing solar PV generates 5%-10% more avoided cost value than residential south-facing solar PV.[38] Although south-facing systems have greater production overall, west-facing systems generate energy later in the day, increasing the portion of generated energy that is coincident with ISO-NE and New Hampshire-specific peak hours. This allows west-facing systems to generate greater value for those avoided cost categories that are driven by peak demand. Customer-

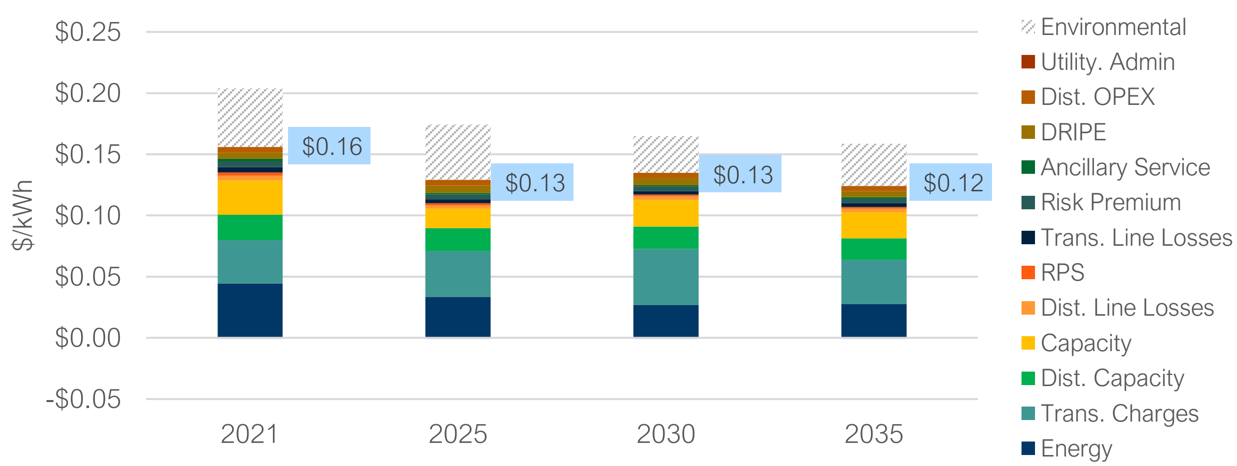
[38] When considering all study years, not only those highlighted in the graphs above, and excluding environmental externalities.

generators in New Hampshire are currently incentivized to maximize solar production by installing south-facing systems, given that those systems produce a greater volume of electricity overall.

Energy is the largest avoided cost criterion for both system types in 2021, representing 28% of the base avoided cost value stack for south-facing systems and 27% for west-facing systems.[39] The value of energy is assumed to decline over time, however, as lower marginal cost resources increasingly participate in the market. By 2035, transmission charges – which are assumed to increase over the course of the study period, based on trends seen in short-term forecasts – become the largest avoided cost criteria for both system types, representing 29% of the base value stack for south-facing systems and 31% for west-facing systems. Accounting for the non-embedded social costs of carbon and nitrogen oxide as environmental externalities increases the value of each system by $0.03-$0.05/kWh (representing 22%-36% of total value for a south-facing system and 22%-34% of total value for a west-facing system).

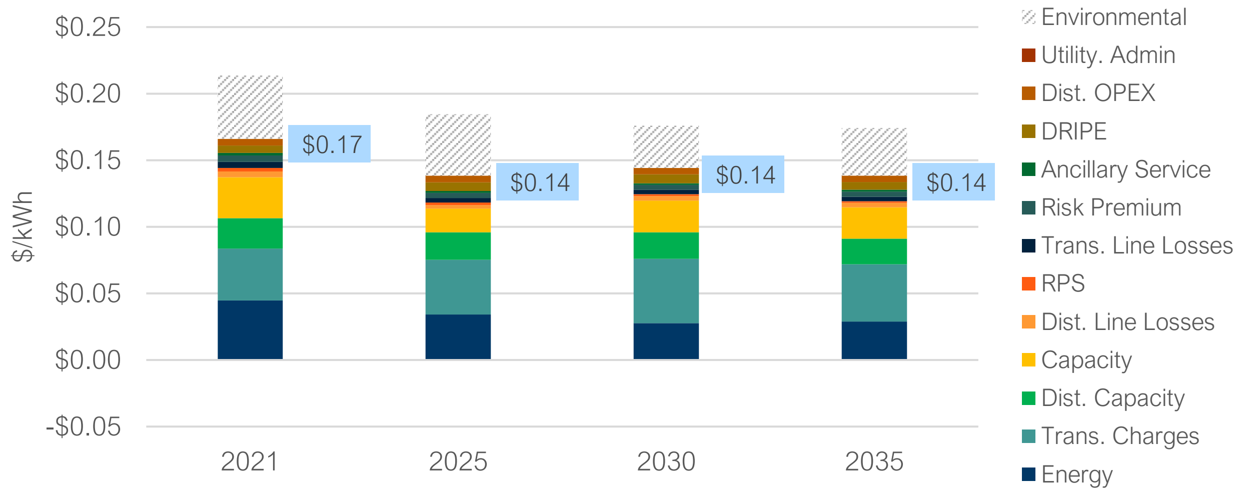
Figure 12 and Figure 13 below show the average annual avoided cost value of commercial south-facing and west-facing systems, respectively, for several years during the study period. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

Figure 12. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2021 (2021$)[a]



[39] The base avoided cost value stack refers to the value stack excluding environmental externalities.

Figure 13. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2021 (2021$) [a]



a. Totals shown are net values and exclude the value of environmental externalities

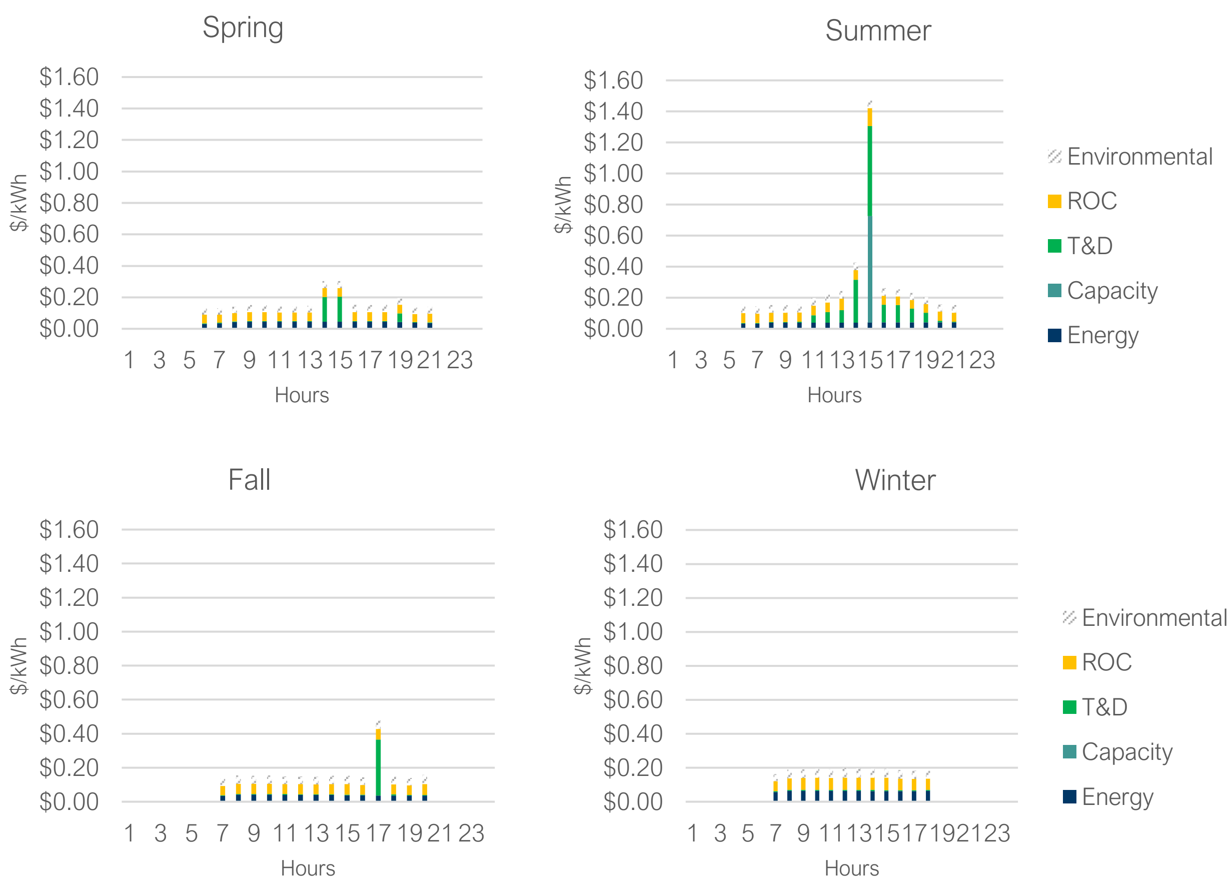
West-facing commercial solar PV systems produce 6%-10% more value than south-facing commercial solar PV systems, again due to their production having greater coincidence with evening system peaks. Commercial solar PV systems with the same orientation as residential systems have the same avoided costs for all criteria with the exception of RPS compliance and distribution line losses. Both the RPS compliance and distribution line loss criteria have sector-specific elements that lead to variations in avoided costs between the sectors.[40] As a result, commercial systems offer slightly less value (1%-2% lower across the study period) than residential systems. Because commercial customer-generators are assumed to consume a smaller portion of the energy produced by solar PV systems behind-the-meter, the reduction in retail sales is less for commercial PV systems, which results in reduced RPS and line loss avoided costs. Moreover, the commercial sector has lower assumed line loss factors than residential systems, again reducing line loss avoided cost value.

The previous graphs illustrate the year-over-year variations in avoided cost values. However, there is also considerable variation throughout a given year due to differences in DER production profiles as well as seasonal changes in demand, congestion, generating resources, and other factors that influence grid conditions. Figure 14 below illustrates how avoided cost value ($/kWh) changes over an average 24-hour period in each season in the year 2021 for a south-facing residential system.[41,42] For ease of presentation,

[40] RPS compliance is calculated using sector-specific assumptions for the portion of DG energy output generated that is consumed behind-the-meter. Line losses account for sector-specific behind-the-meter consumption and sector-specific line loss factors. The sector-specific assumptions used to calculate these values are described in Appendix C.
[41] For brevity, we do not include parallel graphs for a residential west-facing system or commercial systems as the high-level seasonal trends are similar among various solar PV system types. These results can be generated using the accompanying VDER model.
[42] The seasonal avoided cost values for years 2025, 2030, and 2035 are included in Appendix Section B: Results Tables.

the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.

Figure 14. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2021, Year 2021 Shown (2021$)



In most hours, the avoided cost values are lowest during the spring and fall shoulder season days when the ISO-NE system demand is typically at its lowest. A limited number of spring and fall afternoon hours show higher avoided costs due to increased T&D values. These hours coincide with the ISO-NE monthly system peak, when the transmission charges levied on New Hampshire utilities are assessed, which increases load reduction value. Transmission charges also cause a spike to summer avoided costs during the afternoon hours. The summer daytime values are further driven up by the annual ISO-NE system peak, leading to sizable capacity avoided costs.

Avoided cost values may also be impacted by the total system load, or if resources participate in the market. Avoided cost values were assessed under those conditions through the high load growth scenarios (HLGS) and the market resource value scenario (MRVS), respectively. These sensitivity scenarios are described below, and the results are presented in the figure that follows.

High Load Growth Scenarios (HLGS): To a degree, avoided cost values will be affected by total system loads. The study considers how avoided costs could change under higher load conditions, reflecting increased adoption of transportation and building electrification. Generally, it is assumed that increased loads will lead to higher avoided cost values, increasing the value of load reductions from DERs. The figure that follows features the highest load growth scenario assessed, which includes building electrification and transportation electrification assumptions that exceed those included in the AESC.[43] In addition to the baseline value stack, the figure also shows how the avoided costs for environmental externalities are expected to rise with increased overall system load due to an assumption that higher-emitting generating resources will be needed to meet that higher load.[44]

Market Resource Value Scenario (MRVS): Rather than acting as passive resources that generate value merely by reducing loads on the system, net-metered DERs may participate directly in the ISO-NE markets as aggregated resources that provide wholesale market services. For this analysis, DERs are assumed to have the ability to provide energy, capacity, or ancillary services. The energy value that DERs can achieve is assumed to be equal to the avoided cost of energy, and so is unchanged from the value stack assessment. For practical purposes, DERs are assumed to *not* participate in the ancillary services market, even through they do have the ability to provide those services; additional information regarding DER provision of ancillary services is included in the Qualitative Market Resource Value Scenario Insights section of this report. However, the capacity value that DERs can achieve in the wholesale market is different from the avoided cost of capacity as a result of two factors:

1. MW Value: Reducing demand requirements through load reductions, as considered in the value stack assessment, has the benefit of reducing capacity requirements *and* reducing the reserves associated with those capacity requirements. By instead acting as a supply resource, as considered in the MRVS assessment, DERs do not realize the benefits associated with reserve avoidance, generating less total value. In general terms, the value of each MW reduced by a DER through behind-the-meter consumption is of greater value than that of each MW bid into the wholesale market as capacity.

2. Timing of Value: Avoided capacity value attributable to load reduction is assessed according to production during a single hour of the year: the ISO-NE annual system peak hour. In contrast, market capacity value is assessed according to average production during summer and winter reliability hours.[45] Whether a DER provides greater value by reducing load or by participating in the

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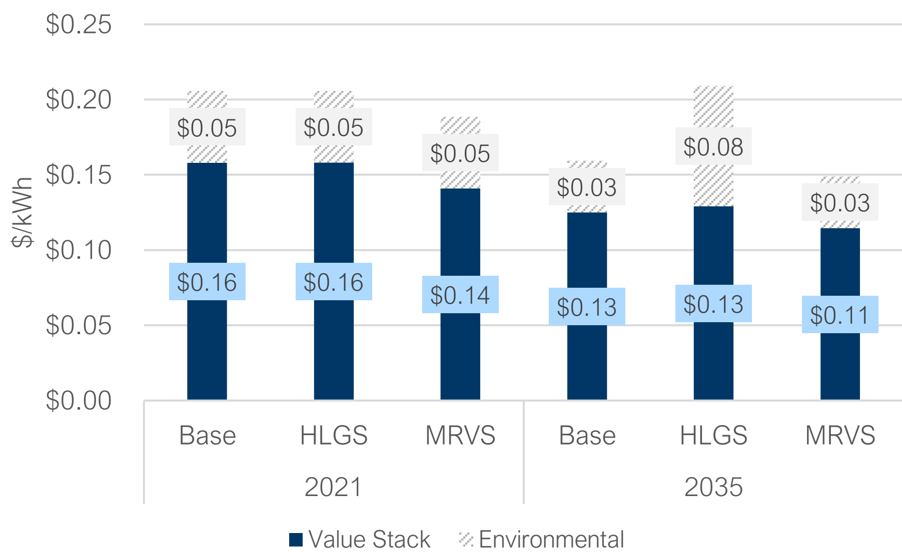
[43] The HLGS analysis includes three load growth scenarios which vary with respect to assumed levels of transportation and building electrification. Scenario 3 – the results of which are highlighted above – assumes higher-than-AESC transportation and building electrification. These scenarios are described in greater detail in Appendix Section D: High Load Growth Scenarios Methodology and can also be explored in the accompanying VDER model.
[44] In the high load growth scenarios, the equation to calculate marginal emissions was developed through a regression analysis between New Hampshire's hourly demand and the associated CO_2 and NOx emissions. The equation does not capture changes in resource mix and market conditions that could result in lower emissions rates.
[45] Additional information regarding reliability hours is included in Appendix Section E: Market Resource Value Scenario Methodology.

capacity market depends on the peak or reliability hours in a given year and the DER's production during those hours.

Mirroring the baseline value stack, the value of the MRVS declines over time. This is primarily a result of declining energy price avoided costs. Market participation may result in changes to avoided cost criteria values beyond energy and capacity (for example, RPS compliance or line losses); however, for the purposes of this analysis, the remaining value stack criteria are assumed be to the same as the baseline value stack.

Figure 15 illustrates the avoided cost value for the baseline avoided cost value stack alongside the HLGS and MRVS for a south-facing residential solar PV array.

Figure 15. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario (MRVS), for Years 2021 and 2035 (2021$)



The HLGS generates approximately the same value as the base value stack in 2021 but has 3% higher value than the base value stack in 2035 excluding environmental externalities (a difference too small to show in the data label). In the early years of the study, the variation in load between the baseline and HLGS is minimal. However, in later years, the cumulative impact of electrification under the HLGS drives increased avoided cost values over the baseline. Under the HLGS, the environmental externalities value is essentially the same as the base value stack in 2021 but increases to 132% of the base value stack in 2035 due to the assumption that higher-emitting resources are required to meet additional load.

Under current wholesale market rules, south-facing residential solar PV systems provide more value to the utility system by passively reducing load than by participating in the energy and capacity markets. That result is mirrored for the west-facing residential system and the south- and west-facing commercial systems. For the south-facing residential system featured in Figure 15 above, the MRVS results in 11% less value than the baseline in 2021 and 8% less value in 2035.

3.2.2 – Residential and Commercial Solar PV Paired with Storage

Avoided cost values are modeled for south-facing solar PV arrays paired with storage for the residential and commercial sectors.[46] Figure 16 and Figure 17 below show the value of these systems for several years during the study period. Detailed results tables showing the average annual value of each of the avoided cost criteria in each study year are included in Appendix Section B: Results Tables. The results shown are for systems installed in 2021, and all values are in real 2021 dollars.

Figure 16. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 (2021$)a

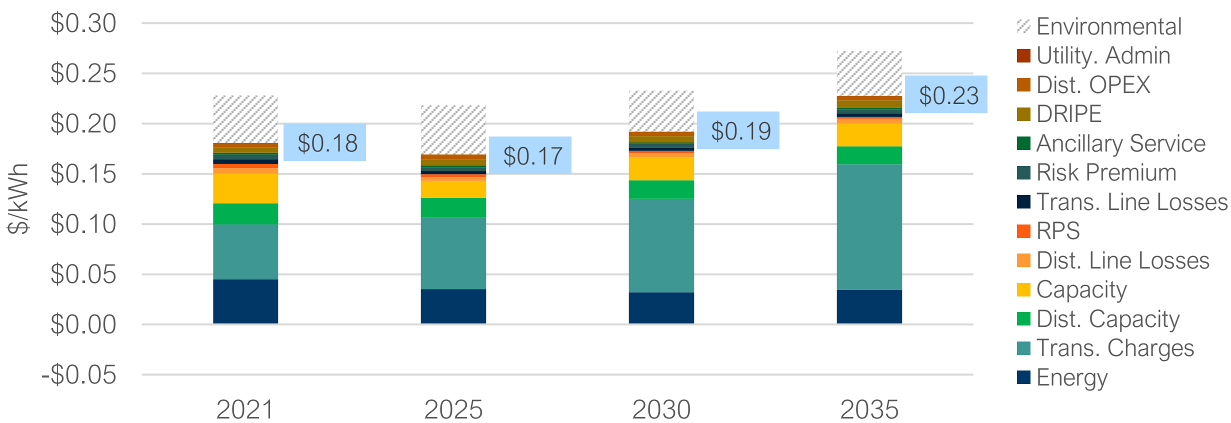
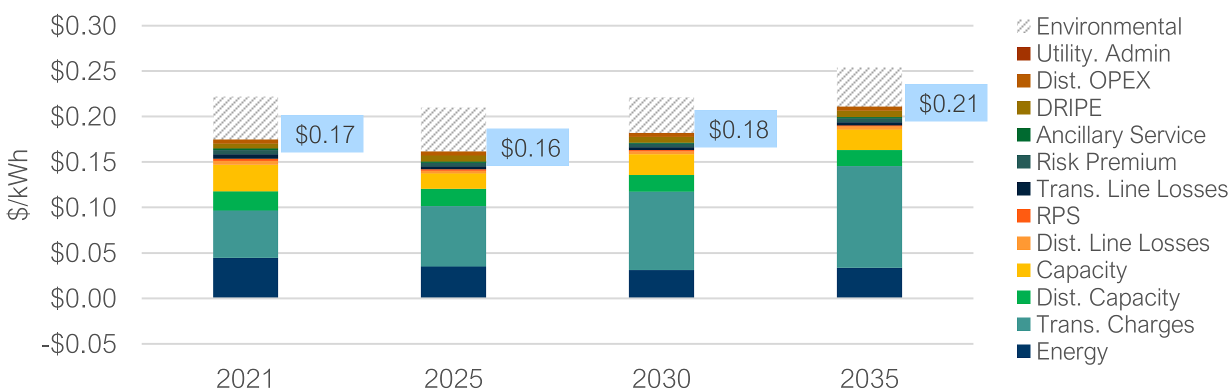


Figure 17. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 (2021$)[a]



a. Totals shown are net values and exclude the value of environmental externalities

46 Although west-facing solar PV arrays paired with storage are not modeled, the accompanying VDER model allows users to input custom resource profiles to generate value stacks for other solar paired with storage configurations using the tool.

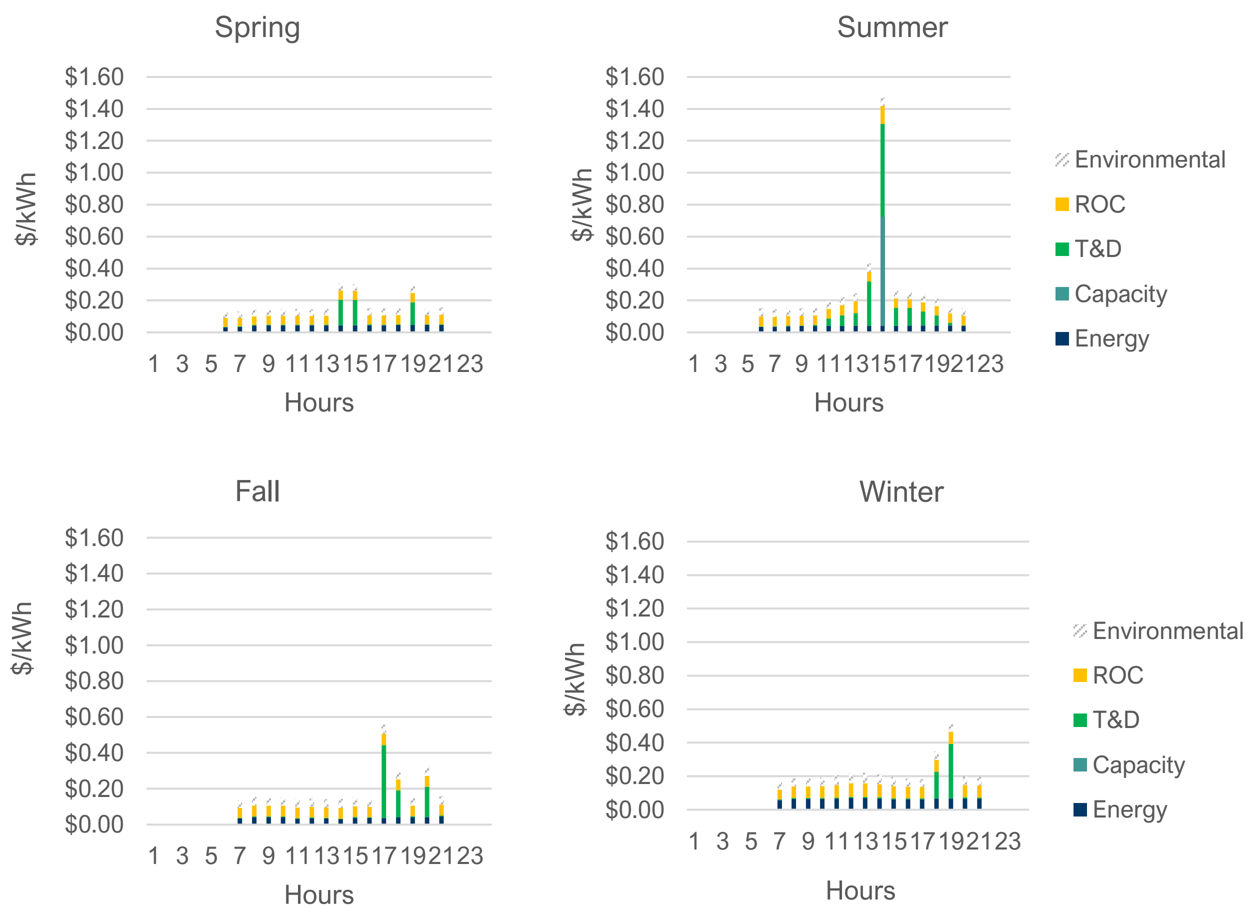
In any given year, residential solar PV systems paired with storage generate between 14% and 82% greater base avoided cost value than solar-only systems; commercial solar PV systems paired with storage generate 12% to 70% greater base avoided cost value.[47] The battery storage system is assumed to be charged with energy generated by the solar array during off-peak times when avoided costs are low and solar generation is high (i.e., HE11 to HE14). The storage system is assumed to discharge during peak periods in the early evening (HE18 to HE21 in Winter and HE17 to HE20 in Summer) when solar production is lower and avoided cost values are higher. This timing of battery charging, and discharging provides considerable additional benefits for many avoided cost categories, including transmission charges, energy, line losses, and DRIPE.

Unlike solar-only systems, the total avoided cost value for solar paired with storage systems increases over time. These increases are primarily a result of transmission charge avoided costs, which are assumed to increase in value over the study period. In 2021, transmission charges are the largest avoided cost value for both system types (30% of the base value stack). By 2035 the value of transmission charges is projected to make up 55% of base avoided cost values for residential systems and 53% for commercial systems while other avoided costs, including energy, decline over time.[48] Environmental externalities increase the value of residential systems by 20%-29% and of commercial systems by 20%-30%.

As with solar-only systems, there is considerable variation within each year as a result of seasonal production patterns and distribution system condition changes. Figure 18 below illustrates how avoided cost values change over an average 24-hour period in each season for a residential solar paired with storage system. For ease of presentation, the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.[49]

[47] The base avoided cost value stack refers to the value stack excluding environmental externalities. These comparisons consider all study years, not just those shown above.
[48] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[49] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

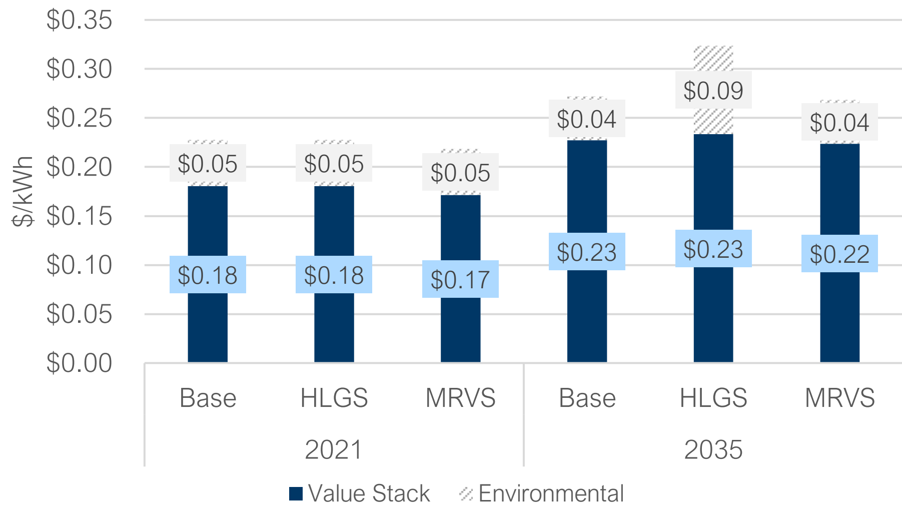
Figure 18. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021, Year 2021 Shown (2021$)



The addition of storage allows these systems to realize greater value than solar-only systems across all seasons. This is particularly the case for T&D costs – solar and storage systems offer load reductions during ISO-NE and New Hampshire peak times during all seasons, achieving greater value.

The avoided cost load reduction values of solar paired with storage systems are also assessed under the HLGS and MRVS. These values are contrasted with the baseline avoided cost value stack for a south-facing residential solar paired with storage system in Figure 19. Because both system types have the same orientation, the commercial system results mirror the residential system results; only residential system results are shown here.

Figure 19. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario, for Years 2021 and 2035 (MRVS) (2021$)

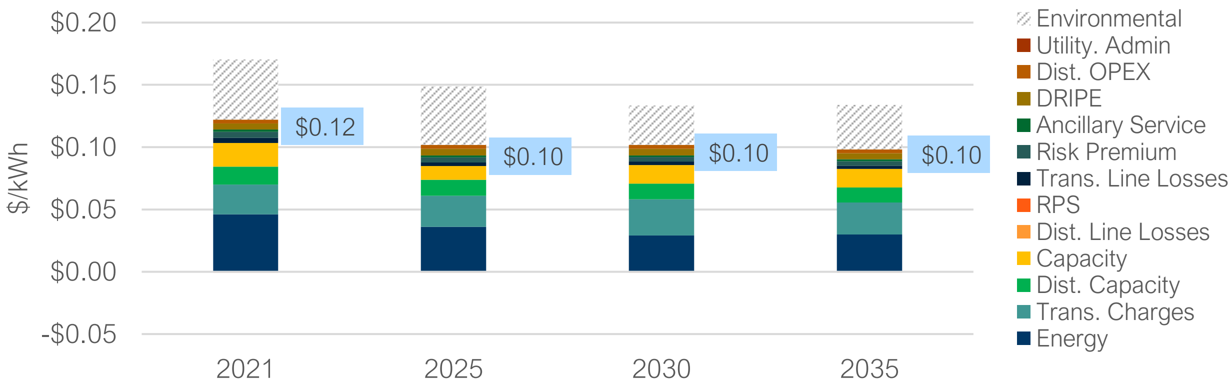


In 2021, the HLGS has approximately the same value (less than 1% difference) as the base value stack, excluding environmental externalities. This increases to nearly 3% higher value by 2035 - again, excluding environmental externalities – as increased transportation and building electrification load impacts increase the per unit costs of meeting system needs. It should be noted that the change is too slight to be captured as an increase in the labels shown above. The HLGS environmental externalities are the same as baseline values in 2021 but 102% higher in 2035. This reflects the assumption that increased electric energy demand will increase the emissions intensity of generating resources on the margin. Considering the market participation impacts modeled under the MRVS, the system realizes 5% less value through direct market participation as compared to passive load reduction in 2021 and 2% less value in 2035.

3.2.3 – Large Group Host Commercial Solar PV

Avoided cost values are modeled for a single-axis tracking large group host commercial (LGHC) solar PV array. Figure 20 shows the value of such a system for several years during the study period. A detailed results table showing the average annual value of each of the avoided cost criteria in each study year is included in Appendix Section B: Results Tables. The results shown are for a system installed in 2021, and all values are in real 2021 dollars.

Figure 20. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 (2021$)a



a. Totals shown are net values and exclude the value of environmental externalities

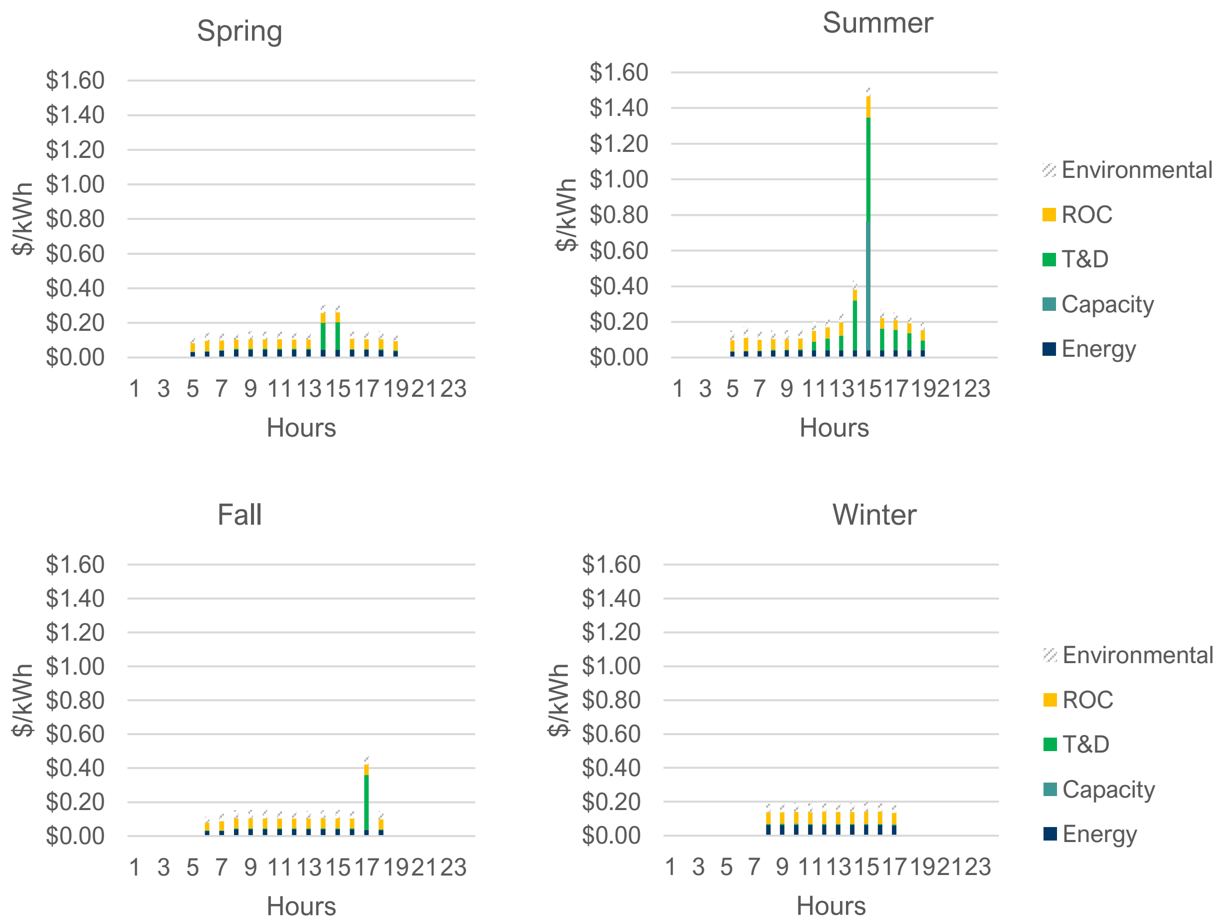
The LGHC solar avoided cost value trends mirror the residential and commercial solar-only system results, declining across the study period largely due to declining energy avoided costs. In a given year, LGHC avoided cost values are lower than residential or commercial systems. Because there is assumed to be minimal load associated with the LGHC system, there is no significant opportunity to reduce retail sales through electricity production to generate RPS compliance avoided cost values. Distribution line loss values are also less as a result of lower assumed line loss values for these systems.

Energy is the largest avoided cost component in all study years, representing 38% of the base avoided cost value stack value in 2021 and 31% by 2035.[50] Environmental externalities increase the total avoided cost value stack value by $0.03-$0.05 per kWh (31%-48% of the total value), varying by year due to changing system emissions intensity.

As with the residential and commercial systems with behind-the-meter load, the LGHC system shows variation by season as a result of shifting production profiles and system conditions. Seasonal 24-hour period averages are shown in Figure 21. For ease of presentation, the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.[51]

[50] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[51] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

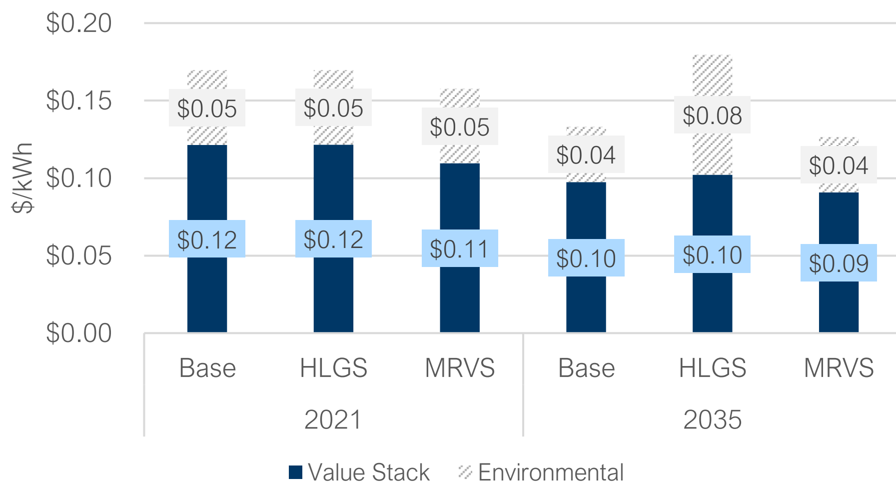
Figure 21. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021, Year 2021 Shown (2021$)



Mirroring the smaller solar-only systems, the LGHC system avoided cost values show a spike in spring and summer late afternoon hours due to avoidance of transmission charges. Capacity values also increase avoided costs during summer afternoons due to coincidence with annual ISO-NE peaks.

As with other system types, LGHC system avoided cost values will vary with total system loads. Furthermore, the value of LGHC systems would change if they directly participated in the wholesale markets. Figure 22 illustrates the avoided cost value for the baseline avoided cost value stack, as well as for the HLGS and the MRVS.

Figure 22. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario (MRVS), for Years 2021 and 2035 (2021$)



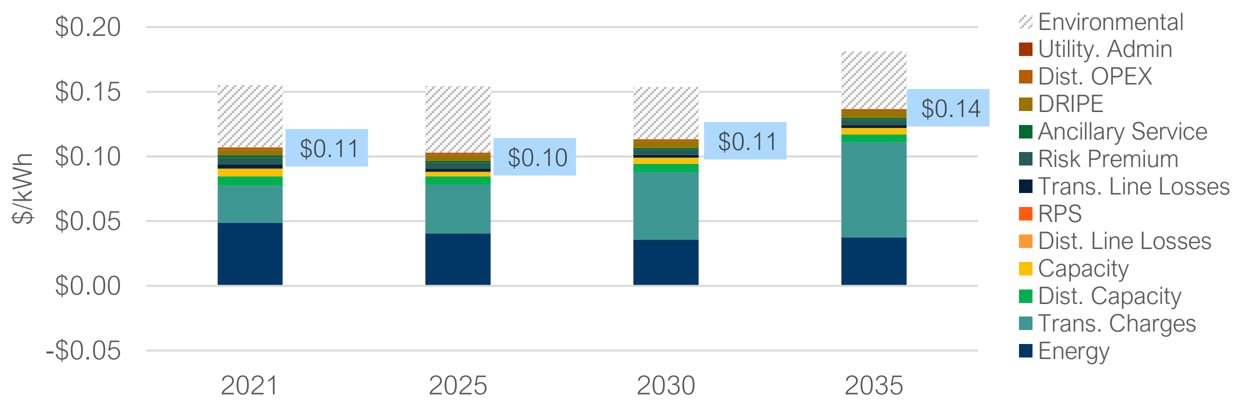
In 2021, the high load growth scenario has approximately the same value (less than 1% difference) as the base avoided cost value stack. In 2035, the high load growth scenario results in 5% higher value excluding environmental externalities. The value increases under the high load growth scenario as increased transportation and building electrification load impacts increase the per unit costs of meeting system needs. High load growth scenario environmental externalities are the same as base values in 2021 but 117% higher in 2035. This reflects the assumption that higher demand will increase the emissions intensity of generating resources on the margin. The system realizes 10% less value through direct market participation as compared to passive load reduction in 2021 and 7% less in 2035, excluding environmental externalities.

3.2.4 – Micro Hydro

Avoided cost values are modeled for a small run-of-river hydroelectric facility. Figure 23 shows the value of such a facility for several years during the study period. A detailed results table showing the average annual value of each of the criteria in each study year is included in Appendix Section B: Results Tables. The results shown are for an existing hydroelectric project.[52] All values are in real 2021 dollars.

[52] The facility is assumed to apply run-of-river operation strategies, where the flow rate into the reservoir behind an existing dam is equal to the flow rate out of the facility.

Figure 23. Average Annual Avoided Cost Value for Micro Hydro Facility (2021$) [a]



a. Totals shown are net values and exclude the value of environmental externalities

Similar to LGHC solar, micro hydro avoided cost value is limited compared to behind-the-meter systems. Because there are assumed to be minimal loads directly attached to the hydro facility, there is no significant opportunity to reduce retail sales through generation, eliminating RPS compliance avoided cost values. Distribution line loss values are also eliminated as hydro systems are expected to export virtually their entire production into the distribution network, and therefore they cannot avoid distribution line loses. Similar to solar paired with storage systems, and in contrast to solar-only systems, the avoided cost value of micro hydro increases from the study start to the study end. Consistent generation allows the hydro facility to achieve significant transmission charge benefits, which are assumed to increase in value over the study period. A slight decline is noted from the early study years to the mid-point in the study period as the value of energy – high in the first years of the study as a result of high natural gas prices – starts to decline.

In 2021, energy is the largest avoided cost criterion, representing 46% of the base avoided cost value stack.[53] By 2035, transmission charges are the largest criterion, representing 54% of the total base avoided cost value. Environmental externalities increase the total avoided cost value stack value by $0.05 in 2021 and by $0.04 in 2035 (45% and 33% of the total value, respectively).

Figure 24 illustrates how avoided cost value changes over an average 24-hour period in each season in the year 2021 for the micro hydro facility. For ease of presentation, the avoided cost criteria are presented as energy, capacity, T&D, Rest of Criteria (ROC), and environmental externalities.[54]

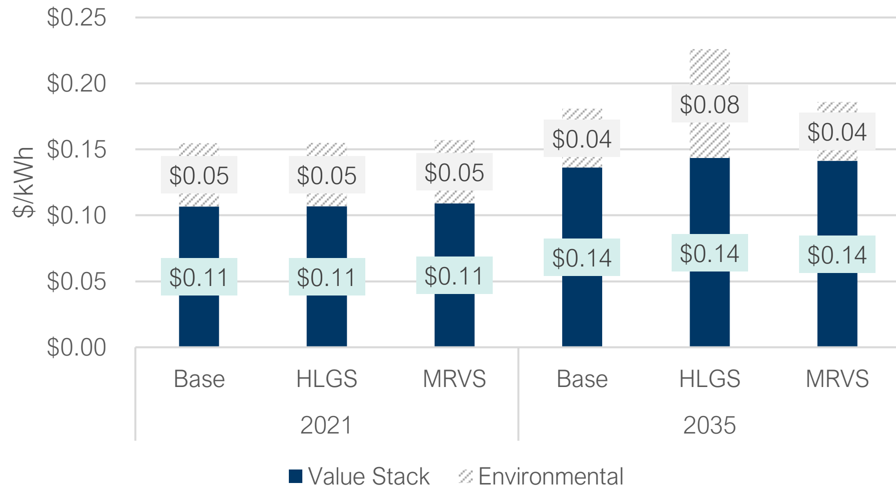
[53] The base avoided cost value stack refers to the value stack excluding environmental externalities.
[54] Here, T&D includes the following quantified avoided cost criteria: transmission charges, distribution capacity, distribution operating expense, transmission line losses, and distribution line losses. ROC includes all quantified baseline criteria with the exception of energy, capacity, and those criteria included in the T&D category.

Figure 24. Average Hourly Seasonal Avoided Cost Values for Micro Hydro Facility, Year 2021 Shown (2021$)

Although micro hydro facilities also experience seasonality effects, their production realizes avoided cost value at all hours of the day and across all seasons. Micro hydro power plants have higher avoided cost values during many hours in the winter season as a result of increased production. In all seasons, production is coincident with monthly ISO-NE system peaks and generates avoided transmission charge benefits. Coincidence with the annual ISO-NE peak also provides capacity benefits during the summer season.

As with other system types, micro hydro facility avoided costs values will vary with total system loads. Also, the value of micro hydro facilities would change should they directly participate in the market. Figure 25 illustrates the avoided cost value for the baseline avoided cost value stack, as well as for the HLGS and the MRVS.

Figure 25. Average Annual Avoided Cost Value for Micro Hydro Facility Under the Baseline Value Stack (Base), High Load Growth Scenario (HLGS), and Market Resource Value Scenario (MRVS), for Years 2021 and 2035 (2021$)



In 2021, the HLGS has approximately the same value (less than 1% difference) as the base avoided cost value, but it grows to 5% by 2035, excluding environmental externalities. Environmental externalities between the base value stack and the HLGS are approximately the same in 2021 but increase to be 85% higher than the base value stack in 2035. Unlike all other system types, micro hydro facilities generate greater value to the system by directly participating in the wholesale energy and capacity markets rather than by just passively reducing load. Unlike the avoided capacity cost value, which is limited to a single annual peak hour, the capacity market value for direct market participants is distributed across a number of hours during ISO-NE's summer and winter reliability periods. The consistent generation of hydro plants realizes greater value during these periods than other system types, resulting in higher values. In 2021, direct market participation generates 2% higher values than the baseline value stack and in 2035 that differential increases to 4%.

3.2.5 – Qualitative Value Stack Criteria

Four value stack criteria were assessed qualitatively; there was not enough data at this time to develop values, or it was determined that they likely had relatively minimal value that did not warrant extensive quantitative analysis. The qualitatively assessed criteria are described below:

Transmission capacity: The AESC outlines a general approach for assessing the value of non-Pool Transmission Facilities (PTF) avoided transmission capacity costs – i.e., those costs related to transmission upgrades that are not covered by RNS or LNS transmission charges - by considering planned expenditures resulting from planned load increases. The New Hampshire utilities that were interviewed, however, did not identify any non-PTF transmission-related expenditures which could be avoided or deferred due to load reductions to support this assessment. The utilities noted that transmission capacity value is primarily covered under the Transmission Charges criteria. The AESC includes a summary of the T&D avoided cost criteria considered by each utility in ISO-NE when screening demand-side management (DSM) measures and programs. Eversource in Connecticut was the only utility included in that review which considers non-PTF avoided costs in addition to PTF avoided costs when evaluating or screening DSM. The non-PTF value is estimated to be 1.1% of the PTF value, supporting the assertion that the Transmission Charge criteria accounts for the vast majority of the transmission system avoided costs that can be realized from reduced loads.

Transmission and Distribution System Upgrades: This criterion is an incurred cost category rather than an avoided cost category. Although individual customers who have installed DG systems are responsible for most if not all of the incremental investment required to support their systems, future DG deployment is expected to have a cumulative impact on the system not attributable to any single customer which may require utility investment. Through interviews, the utilities acknowledged that this would likely be the case in the future as DER penetration on the system increases, but they were not able to quantify the values as, to date, all upgrades associated with DER installations have been funded by the customer-generators.

Distribution Grid Support Services: This criterion may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs for distribution system support services required as DER penetration increases. For example, costs may be incurred to correct for voltage issues caused by DERs. On the other hand, some DER resources can provide support services such as power factor correction or power quality support, potentially resulting in avoided costs to the utilities. Beyond converting direct current energy to alternating current energy, advanced solar PV inverters are increasingly designed to serve additional functions related to grid integration and monitoring. During the interviews, the utilities noted that they have not required additional grid support services as a result of DER installation to-date, nor have they tested the full functionality of advanced inverters. They also indicated that support service functionality offered by advanced inverters may simply be used to correct issues caused by the associated DER systems; therefore, it is unclear whether there would be a net benefit from a system perspective. At least one of the utilities is planning a pilot to test advanced inverter support functionality as part of its grid modernization plan, so data to support the valuation of this criterion may become available in the future.

Resiliency: A formal definition of resiliency has not been developed in New Hampshire regulation or for the purpose of energy efficiency programs and policies. In this study, “resilience services” are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[55] In order to provide such resilience services, DERs must be configured as microgrids, or a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can operate in both grid-connected and island-mode.[56] To use DERs in a microgrid context, additional equipment is required beyond that associated with typical systems used in net-metering applications. Requirements vary according to need; for example, manually establishing a grid-islanded load will require less investment than advanced applications that can centrally control load shedding and generator output.[56] The costs and benefits of microgrid installations will vary from site-to-site, as each installation requires site-specific analysis, engineering, and equipment. Planning solar PV systems to be microgrid-ready can be a low- or no-cost way to facilitate installation of equipment

[55] This definition was sourced from the U.S. DOE Office of Energy Efficiency and Renewable Energy, available online: https://www.energy.gov/eere/femp/distributed-energy-resources-resilience.
[56] U.S. DOE. (2019). Energy Exchange Pre-Conference Workshop: Distributed Energy Technologies for Resilience and Cost Savings. Available online: https://www.nrel.gov/docs/fy19osti/74625.pdf.

required for microgrid applications at a later date.[57] This may include selecting inverters that are able to interact with the grid or operate in microgrid modes, inverters that are responsive to microgrid controllers, or simply ensuring there is space onsite near the DER installation for additional components in the future.

A report from the National Association of Regulatory Utility Commissioners (NARUC) found previous regulatory proceedings that have attempted to value resiliency but were unsuccessful at arriving at a quantified value of resilience services.[58] The report noted that resilience value has been quantified in non-regulatory proceedings, but these have been highly context specific.

Regulatory bodies in New Hampshire have not yet explored a definition for resiliency in the state nor considered the metrics that might be used to measure resiliency. There may be an opportunity to consider additional ways to value resiliency should these definitions or metrics be developed in the future. Opportunities for DER microgrids are being actively investigated by researchers and utilities across the country. Those initiatives may also provide insights about the value of resiliency from DERs in New Hampshire moving forward.

3.2.6 – Qualitative Market Resource Value Scenario Insights

Ancillary services are wholesale market functions that ensure the reliability of the bulk power system through the dispatch of low-cost and fast-responding resources. Traditional dispatchable resources, such as natural gas combustion turbines, provide ancillary services such as regulation, 10-minute spinning, 10-minute non-spinning, and 30-minute operating reserves. However, in the future, such services potentially could be provided by aggregated DERs such as solar PV, energy storage, or micro hydro facilities.

Micro hydro facilities are traditionally run-of-river systems, where the flow rate into the reservoir matches the flow rate out of the facility. Since such a facility's output flexibility is constrained, it would be technically challenging for such facilities to provide ancillary and balancing services. On the other hand, solar PV has the technical capability to provide regulation and balancing services through precise output control. Solar would traditionally reduce its output and make itself available to provide up or down regulation services either by increasing the generation (to the technical max) or reducing its output. It is often required that resources providing ancillary services do not participate in the energy market, however. Because wholesale energy is currently a significant value driver, it is considered unlikely that such generation systems would sacrifice energy values for ancillary services values.

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[57] NREL. (2017). Microgrid-Ready Solar PV – Planning for Resilience. Available online: https://www.nrel.gov/docs/fy18osti/70122.pdf.
[58] NARUC. (2019). The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices. Available online: https://pubs.naruc.org/pub/531AD059-9CC0-BAF6-127B-99BCB5F02198.

3.3 – Levelized Customer Installed Costs

This section addresses levelized customer installed costs for the systems modeled for the study. The costs[59] in each year represent the net present value of total lifetime capital and operational costs for a system installed *in that year* levelized by the system's total lifetime energy production: the levelized costs in 2021 represent the lifetime costs of a system installed in 2021, while the levelized costs in 2035 represent the lifetime costs of a system installed in 2035.[60]

The costs account for available incentives, notably the Federal Solar Tax Credit, but do not account for benefits from net-energy metering participation. These costs could be compared to levelized net-metered customer-generator tariff compensation to assess cost-effectiveness and in future proceedings to evaluate potential tariff impacts on reasonable opportunities to invest in and receive fair compensation for net metering systems, per House Bill 1116 (2016), from the customer-generator perspective.[61]

Table 3. Levelized Customer Installed Costs by System Type

System Type	Lifetime $/kWh Cost			
	2021	2025	2030	2035
Residential solar, south-facing	$0.07	$0.06	$0.04	$0.04
Residential solar, west-facing	$0.09	$0.08	$0.05	$0.05
Commercial solar, south-facing	$0.04	$0.04	$0.03	$0.03
Commercial solar, west-facing	$0.06	$0.06	$0.04	$0.04
Residential solar, south-facing, paired with storage	$0.10	$0.10	$0.06	$0.06
Commercial solar, south-facing, paired with storage	$0.07	$0.06	$0.05	$0.04
Large Group Host Commercial Solar	$0.05	$0.06	$0.04	$0.04
Micro hydro	$0.06	$0.06	$0.06	$0.06

Generally, solar costs are assumed to decline over time, with the exception of a short-term increase in costs as the Federal Solar Tax Credit expires (assumed for this study to expire in 2024).[62] The lower energy production of west-facing systems increases their costs over south-facing systems on a levelized basis, while the larger size of commercial systems – in particular LGHC systems – allows them to benefit from economies of scale, resulting in lower levelized costs.

[59] Costs were informed by the NREL Annual Technology Baseline, available online: https://atb.nrel.gov/
[60] Costs include all administrative and project management costs associated with project development and operation, inverter costs at year 15 (for solar systems), and general maintenance costs.
[61] A levelized net-metered tariff is not included in this study.
[62] Additional information about the source for the projected technology cost declines is included in Appendix Section C.18: Customer Installed Costs.

South-facing residential solar with storage systems are assumed to have 50% to 66% higher levelized lifetime costs than south-facing residential solar-only systems, varying by year. Commercial south-facing solar and storage systems are assumed to have 51% to 56% greater levelized lifetime costs than commercial south-facing solar-only systems.

It is expected that few if any new hydro dams and reservoirs will be constructed in New Hampshire during the study period. As a result of recent amendments to New Hampshire's net energy metering program eligibility, micro-hydro systems between 1 and 5 MW in size that are operating as municipal group hosts can now participate in net-energy metering programs. Given this change, it is possible that existing dams and reservoirs will be energized in order to participate. As such, the customer levelized installed costs include the upfront capital and ongoing operations and maintenance costs associated with energizing an existing dam and reservoir. Only considering operation and maintenance expenses – in order to assess costs for existing energized systems – is expected to decrease levelized micro hydro facility levelized costs by approximately 60%. No changes to costs due to technology improvements are forecasted over the study period.

3.4 – Rate and Bill Impacts

The Rate and Bill Impacts analysis provides high-level insights into the impact of future DG deployment in New Hampshire on ratepayers. The goal of the assessment is to provide a future-looking estimate of the direction and magnitude of the impacts of DG deployment on all ratepayers and to identify any potential cost-shifting between customers with and without DG. The Rate and Bill Impacts assessment is not intended to be a projection of future electricity rates and cost recovery, but it serves as a future-looking approximation of the impacts of future DG adoption on retail electricity rates for New Hampshire customers.

The reported results[63] in this study analysis are predominantly focused on two key metrics:

- **Rate impacts** are presented as the average annual percentage increase/decrease in rates relative to a no-DG scenario over the period 2021 to 2035 for each rate class and each utility.[64]
- **Bill impacts** are presented as the average annual percentage increase/decrease in customers' bills relative to a no-DG scenario over the period 2021 to 2035 for each rate class, each utility, and each customer type – those with DG and those without DG.

To illustrate the impacts of different potential DG program designs on ratepayers, the analysis is conducted under two different scenarios for DG compensation: a **NEM Tariff Scenario**, which assumes that DG exports are compensated under the current NEM tariff structure, and an **Avoided Cost Value Stack (ACV) Tariff scenario,** which assumes that DG exports are compensated at rates equal to the calculated avoided cost value stack.[65] The ACV scenario illustrates the impacts on rates and bills of a net-metering export tariff that is aligned with the avoided cost value stack, and therefore representative of actual values achieved from the perspective of the utility system.

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[63] The results do not assume inflationary effects and consider only real impacts.
[64] The no-DG scenario is defined as a scenario that assumes no incremental future deployment of DG in New Hampshire post-2021.
[65] NEM 2.0 Tariff adopted September 2017

3.4.1 – NEM Scenario

This scenario reflects the net-metering program that is currently in effect in New Hampshire (effective as of September 2017).[66] The export credit rate is based on the alternative net metering tariff, under which monthly net exports from residential and small general service customer DG (i.e., those with DG facilities up to 100 kW) are compensated at 25% of the distribution rate component and 100% of the generation and transmission rate components. For exports from customers with DG greater than 100 kW, hourly net exports are compensated at 100% of the generation rate component only.

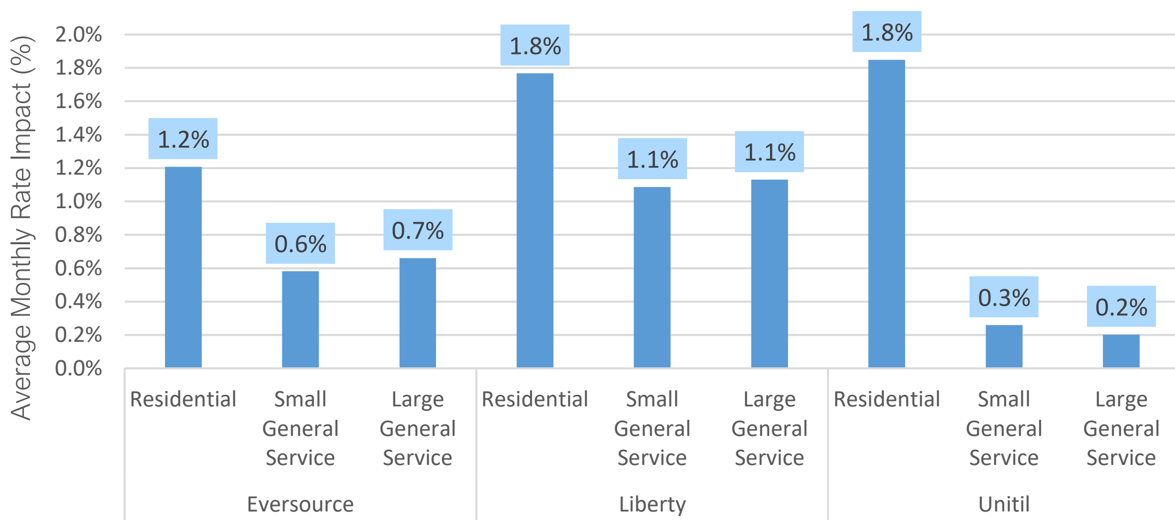
3.4.1.1 – Rate Impacts

Under the current NEM Tariff scenario, forecasted DG adoption is expected to result in slight rate increases relative to a no-DG scenario over the study period (2021-2035), as seen in Figure 26. Across the three utilities, residential customers experience the highest increase in rates among the rate classes, followed by small and then large general service customers.

This variation in retail rate increases across the rate classes is a by-product of sector-specific retail rate designs (rates and tariff structures) and NEM program administration costs, as well as the assumed proportion of solar exports relative to the overall customer load. Customers with net DG exports are compensated through monetary credits at the rates applicable under the current alternative net metering tariff. Rate classes that exhibit a higher proportion of net exports receive greater compensation through export bill credits. This will increase the utility's program costs which in turn will be recovered from the retail customer class. Additionally, the proportion of DG production that is self-consumed will reduce the consumption that is registered behind the meter and result in lost revenues for the utilities. Both the export bill credits and the lost revenues increase the utility costs that need to be recovered, increasing rates. Statewide, average monthly rate increases across the study period are found to be 1.3% for residential customers, and 0.5% for small and large general service customers. Variation is also observed among utilities as a result of differences in system archetype definitions, DG forecast assumptions, and individual utility rate designs.[67,68]

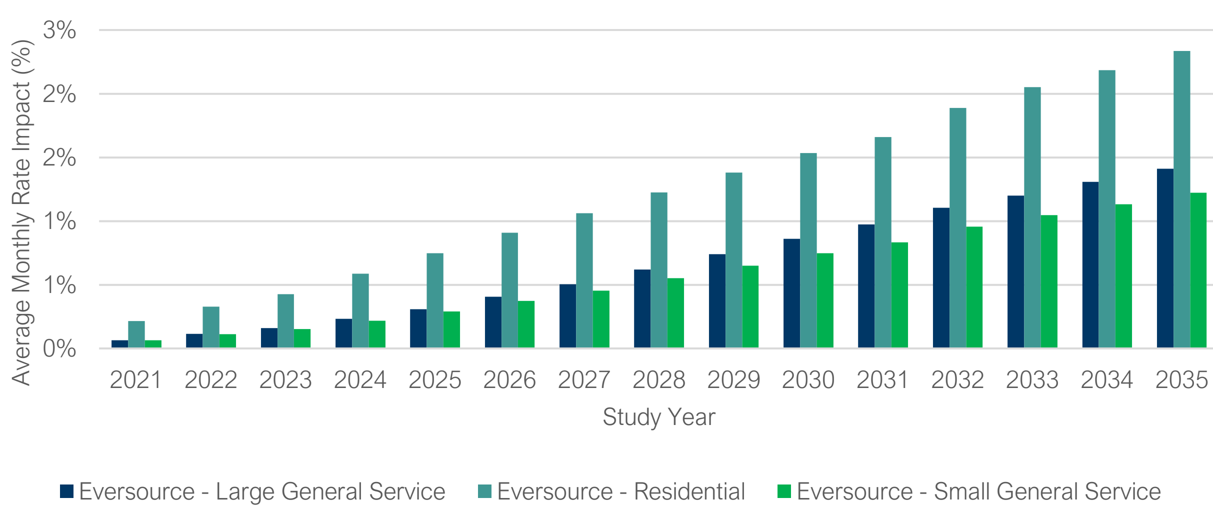
[66] New Hampshire Department of Energy. Net Energy Metering Tariff. Available online: https://www.energy.nh.gov/sites/g/files/ehbemt551/files/inline-documents/sonh/net-metering-tariff-2020-overview.pdf
[67] System archetype definitions are described in methodology section 2.6.1 – Define DG System Archetypes section
[68] DG forecast assumptions are described in methodology section 2.6.2 – Develop DG and no-DG Load Forecasts

Figure 26. Average Monthly Rate Impact for Average Utility Customer (2021-2035) under NEM Compensation Scenario (Relative to no-DG Scenario)



As seen in Figure 27, the average monthly rate impact for utility customers in Eversource's service territory increases gradually over the study period, with residential customers experiencing the greatest increase followed by small and then large general service customers.

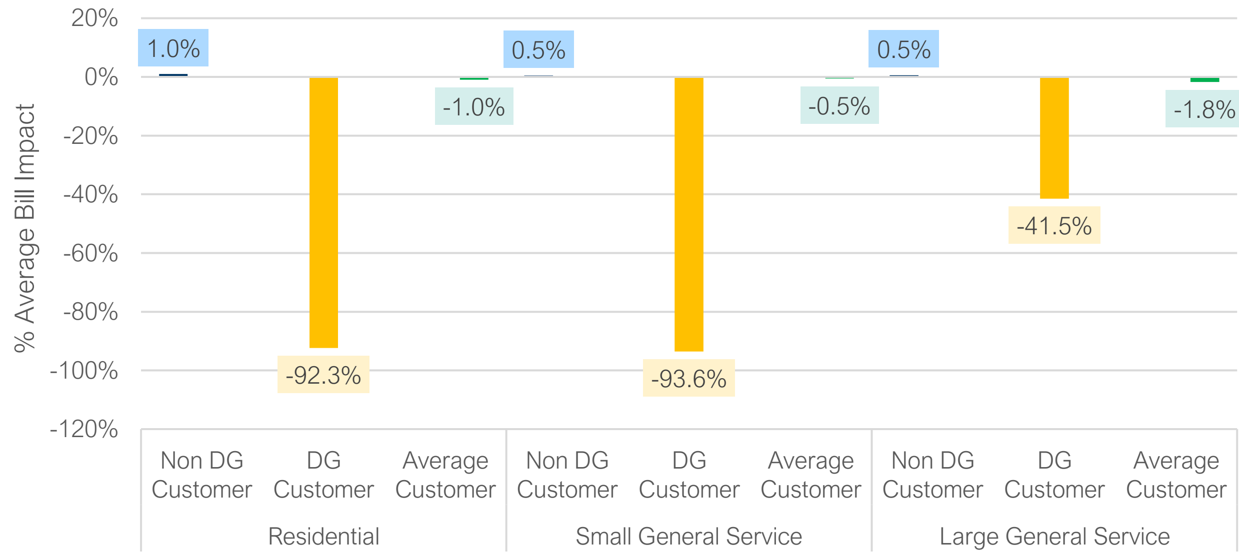
Figure 27. Average Monthly Rate Impact for Utility Customers in Eversource Territory Under NEM Scenario (Relative to no-DG scenario)



3.4.1.2 – Bill Impacts

Among customers with DG, customers without DG, and the average utility customer, DG customers will experience the largest reduction in monthly bills. Figure 28 below illustrates the findings for customers in Eversource's service territory as an example.[69]

Figure 28. Average Monthly Bill Impacts Across Rate Classes in Eversource Territory Under NEM Scenario (Relative to no-DG Scenario)[70]



In the example above, for the system archetypes defined for this analysis, residential and small general service DG customers who adopt behind-the-meter solar see an average reduction of 92% in monthly bills. Large general service DG customers see an average reduction of 42% in monthly bills. Customers who do not adopt DG see a slight increase in monthly bills (~1% for residential and 0.5% for small and large general service customers). Overall, however, the average impact across each rate class, referred to as the "average utility customer" impact is a reduction in monthly bills from 0.5% to 1%.

The following sections present the bill impacts for each customer archetype – DG customer or non-DG customer – as well as the overall average customer impact across the residential and general service customer classes in each utility service territory.

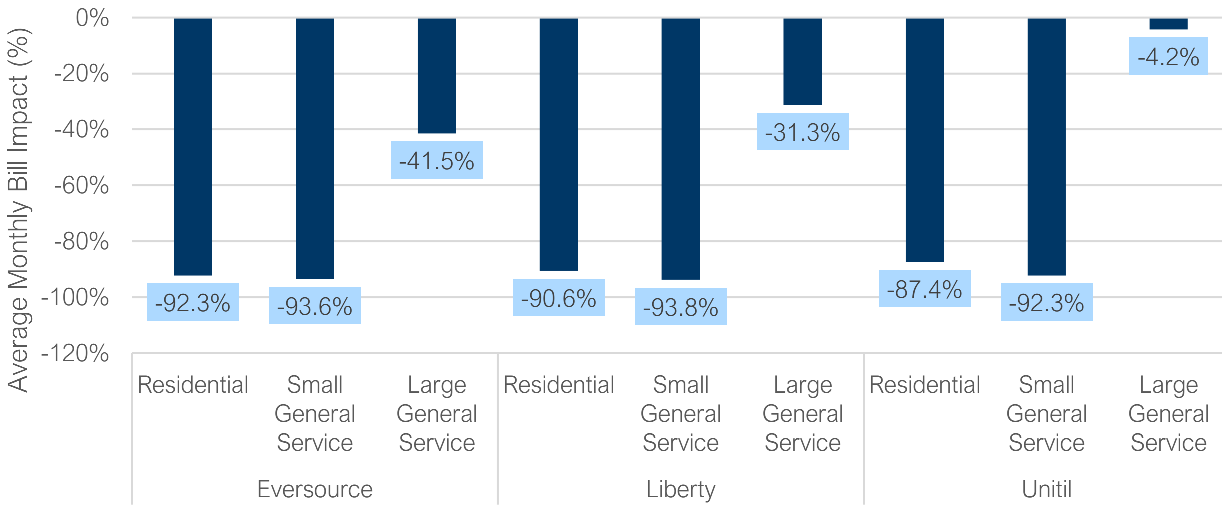
DG Customers

As seen in Figure 29, DG customers across all utilities will observe a significant reduction in monthly bills. Over the study period, residential customers who adopt DG will have 87% to 92% in average monthly bill reductions. Similarly, small general service customers will have approximately 93% in average monthly bill reductions. Large variation is seen in average monthly bill reductions for large general service customers across the three utilities, ranging from 4% to 40%. This is primarily due to

[69] This reflects monthly bills and does not include the costs of installation and ownership of solar PV systems.
[70] Averaged across the study period

the significant variation in the utility-specific average PV system sizes when compared to the overall customer load.

Figure 29. Average Monthly Bill Impact for DG Utility Customer Under NEM Scenario (2021-2035) (Relative to no-DG Scenario)[71]

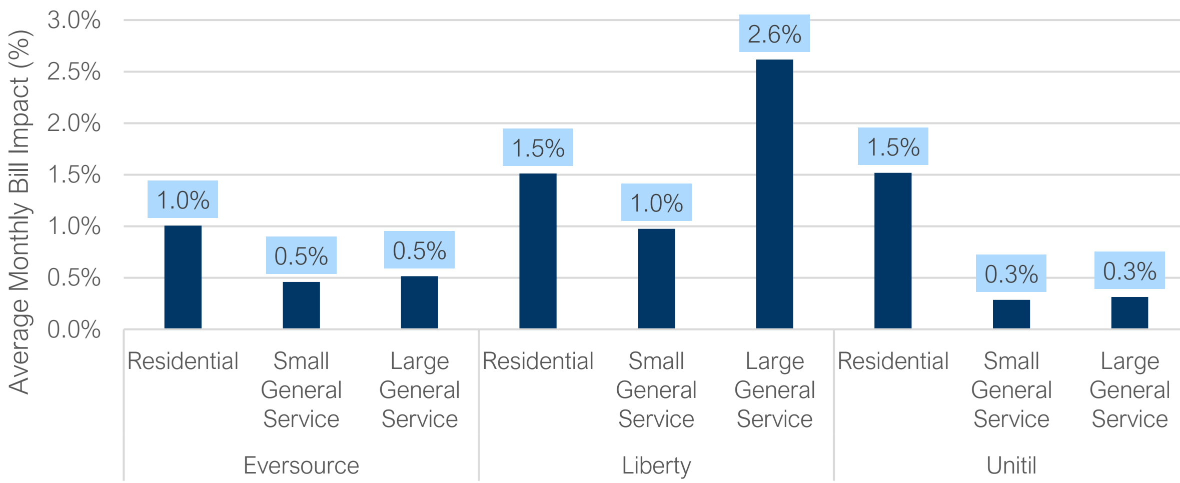


Non-DG Customers

As seen in Figure 30, utility customers that do not adopt DG experience a slight increase in bills across all utilities and rate classes. Residential customers see on average a 1.0 to 1.5% increase in average monthly bills, while small and large general service customers see on average a 0.3% to 2.6% increase in average monthly bills. The largest increase in customer bills is observed for large general service customers in Liberty's service territory. This is a result of Liberty's large generation service rate design, which is more demand-based than the other utilities, and also a result of Liberty having the highest expected proportion of large general service DG customers among the three utilities by 2032.

[71] Averaged across the study period

Figure 30. Average Monthly Bill Impact for Non-DG Utility Customer Under NEM Scenario (2021-2035)(Relative to no-DG Scenario)[72]

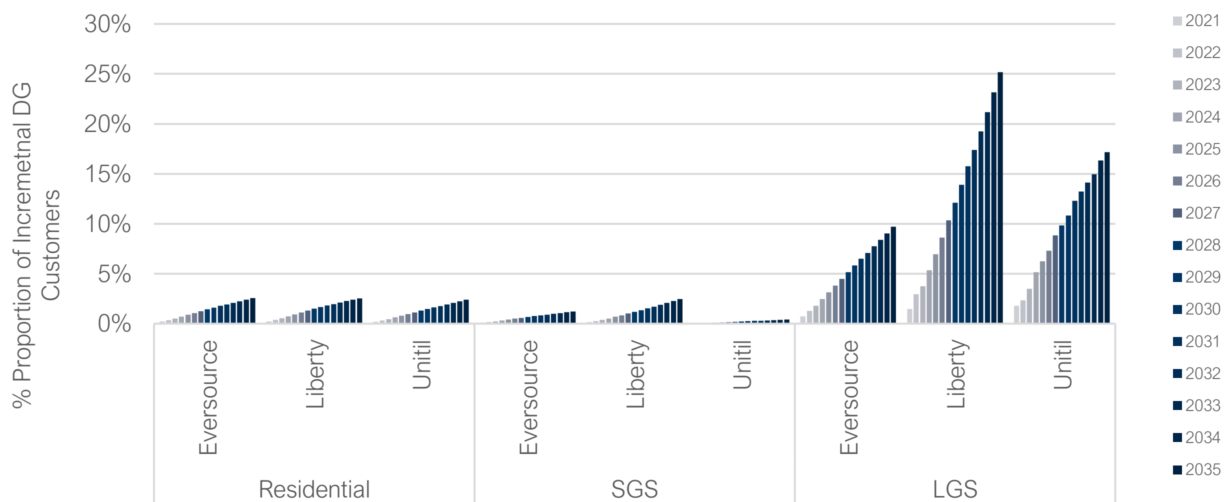


Average Customers

The adoption of distributed solar PV would enable DG customers to experience significant reductions in bills, while resulting in a slight increase in bills for customers who do not adopt DG. Average impacts across all customer types can be assessed by considering DG customer bill impacts, non-DG customer bill impacts, and the proportion of customers that fall into each category. The proportion of DG customers to non-DG customers varies over time for each utility and within each rate class, as illustrated below.

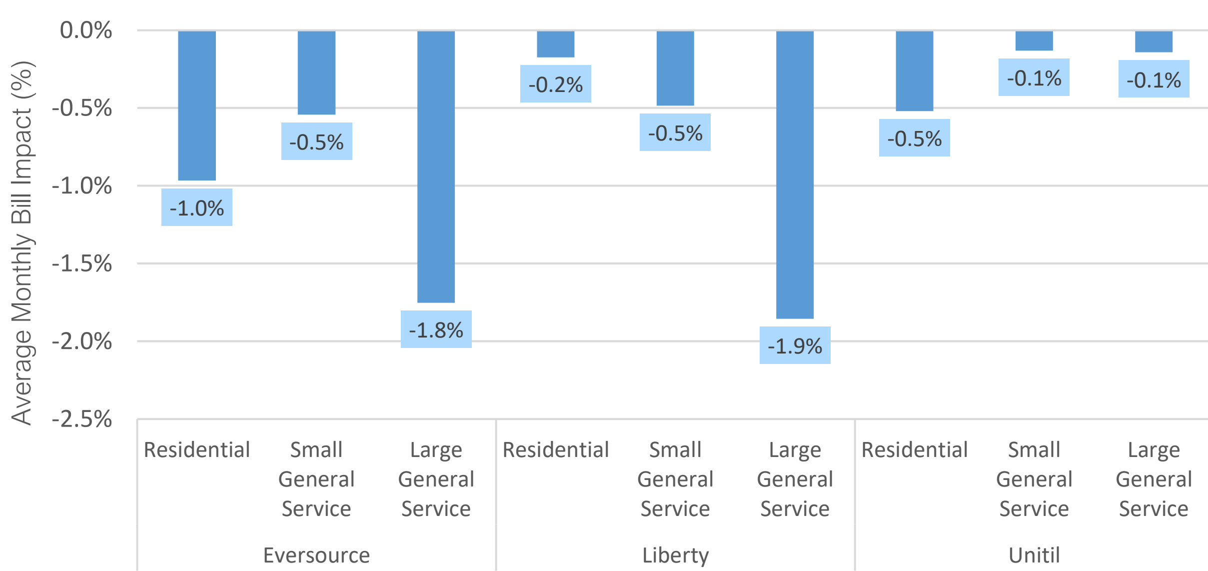
[72] Averaged across the study period

Figure 31. Proportion of Incremental DG Customers Across Rate Classes in Each Utility Service Territory[73] (Relative to no-DG Scenario)



Despite the forecasted electricity rate increases, average monthly bills across all utilities and rate classes are expected to decline over the study period. This is because the average reduction in consumption compensates for the rate increases, resulting in bill decreases overall.

Figure 32. Average Monthly Bill Impact for Average Utility Customer Under NEM Scenario (2021-2035)(Relative to no-DG Scenario)[74]



[73] The proportion of DG customers informed by the utility interconnection data and the CELT forecasts for New Hampshire.
[74] Averaged across the study period

3.4.2 – Avoided Cost Value (ACV) Tariff Scenario

The Avoided Cost Value (ACV) Tariff scenario represents a hypothetical scenario under which net exports from DG are compensated at the avoided cost value, as quantified by the base avoided cost value stack assessment. The treatment of net export compensation is the key differentiator between the two tariff scenarios. Under the NEM Tariff scenario, exports are compensated at a rate that represents a proportion of the underlying retail rates, whereas under the ACV Tariff scenario, net exports are compensated based on the value of the avoided costs calculated in this study (excluding environmental externalities). Because net export bill credits are determined based on the avoided cost values under the ACV Tariff, which is effectively less than the current export compensation rate, the program costs that are recovered by the utilities are lower. Consequently, the ACV has a slightly lower impact on retail rates.

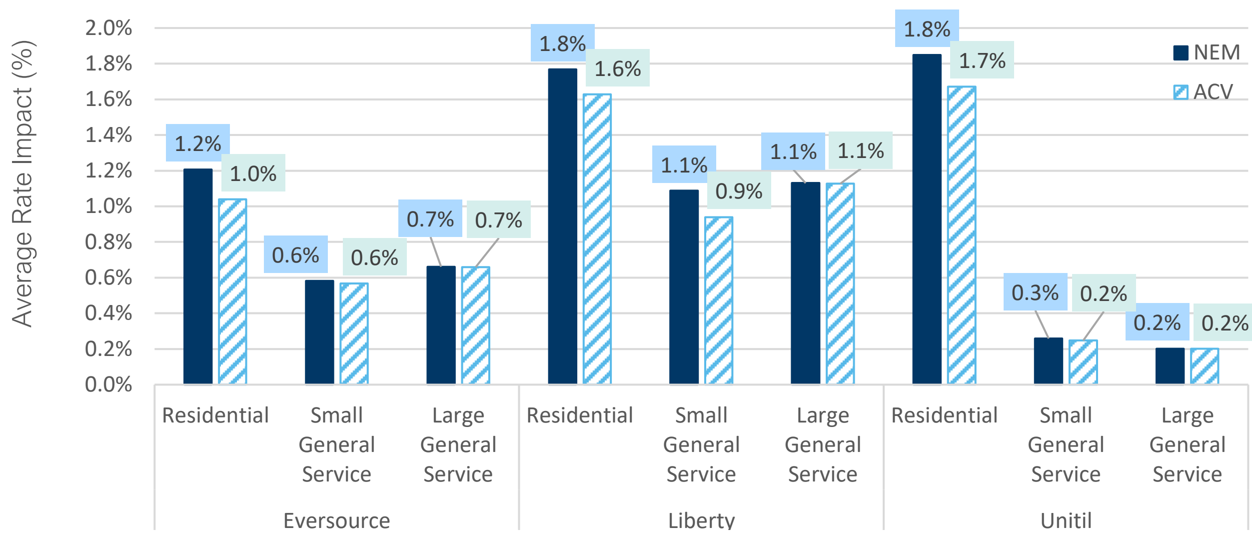
It is important to note that the analysis <u>does not</u> consider any impacts that the transition to an ACV Tariff compensation model may have on DG economics and deployment trends in New Hampshire (i.e., the same level of future DG deployment is assumed under both scenarios).

3.4.2.1 – Rate Impacts

Comparing the rate impacts (relative to a no-DG scenario) for the ACV Tariff scenario with the current NEM Tariff scenario highlights that both scenarios result in slight increases in rates. As seen in Figure 33, both the NEM and ACV scenarios show a comparable increase in rates across most customer classes; however, slightly lower rate impacts for some customer classes are observed under the ACV Tariff scenario.

As discussed above, the effective compensation of net exports is the primary driver for the rate impacts observed. Therefore, differences in rate impacts are primarily observed in rate classes where a significant portion of the electricity produced is exported to the grid. For example, residential customers across all three utilities experience slightly lower rate increase impacts under the ACV Tariff when compared against the current NEM scenario. The rate impacts experienced for small and large general service customers are similar between the NEM and ACV Tariff scenarios, due to the high proportion of energy production that offsets on-site consumption (i.e., assumption of little to no net exports).

Figure 33. Average Rate Impact by Utility and Rate Class (2021-2035) (Relative to no-DG Scenario)[75]



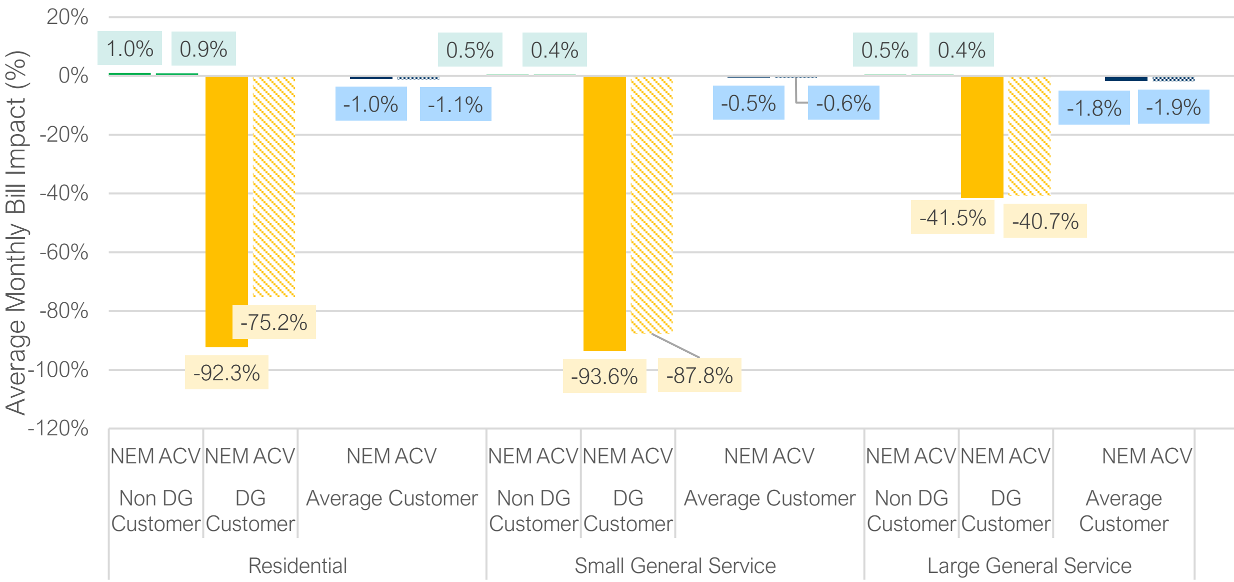
3.4.2.2 – Bill Impacts

A similar trend is observed for bills under the NEM Tariff scenario and the ACV Tariff scenario, where bill impacts do not change significantly for most customers under the two alternative scenarios. Figure 34 below illustrates the findings for customers in Eversource's service territory as an example.[76]

Overall, non-DG customers experience slightly lower bill impacts due to the lower rate impacts under the ACV Tariff scenario, DG customers observe lower bill savings due to the reduced benefits from lower net export credits, while utility customers on average observe slightly higher bill reductions. The following subsections describe the impacts for each of the three representative customer types.

[75] Averaged across the study period
[76] This reflects monthly bills and does not include the costs of installation and ownership solar PV systems.

Figure 34. Bill Impacts Across Rate Classes in Eversource Territory Under ACV and NEM Scenarios (Relative to no-DG Scenario)[77]

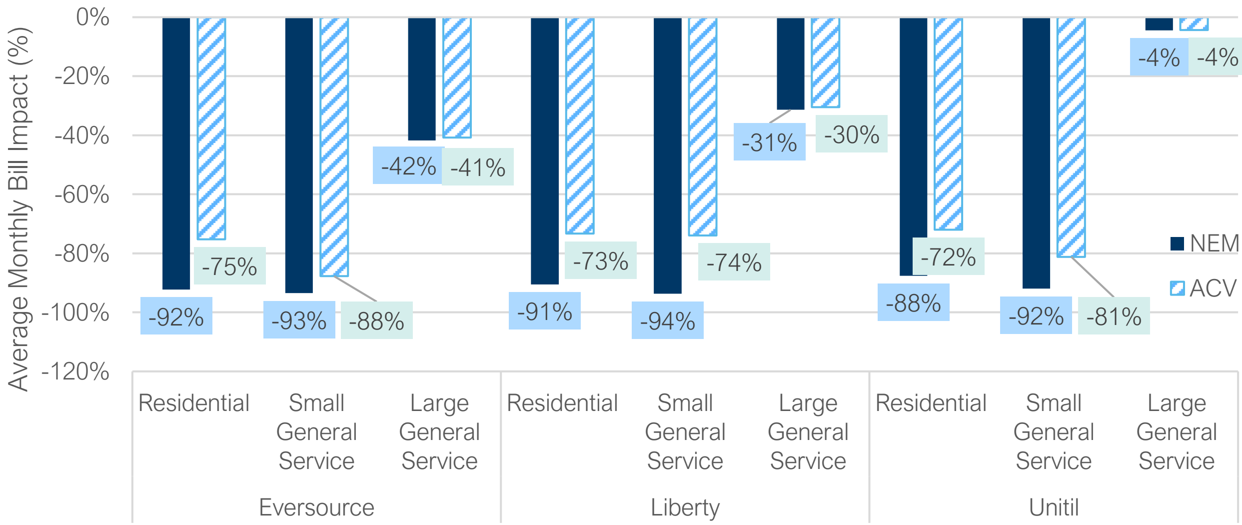


DG Customers

Under the ACV Tariff scenario, most DG customers will experience a reduction in bill savings relative to NEM as a result of the reduced value of net export credits. The impacts will be most prominent in rate classes with high levels of grid exports which makes them more sensitive to changes to net export credits. Specifically, residential customers would experience 72-75% bill savings under ACV as compared to 88-92% bill savings under NEM, an 18% difference in bill savings. Similarly, small general service customers would experience reductions of up to 20% in their average monthly bill savings as compared to their savings under the NEM Tariff scenario. Conversely, large general service customers would experience minimal impacts in their average monthly bills, because of the large share of DG self-consumption assumed for those customers.

[77] Averaged across the study period

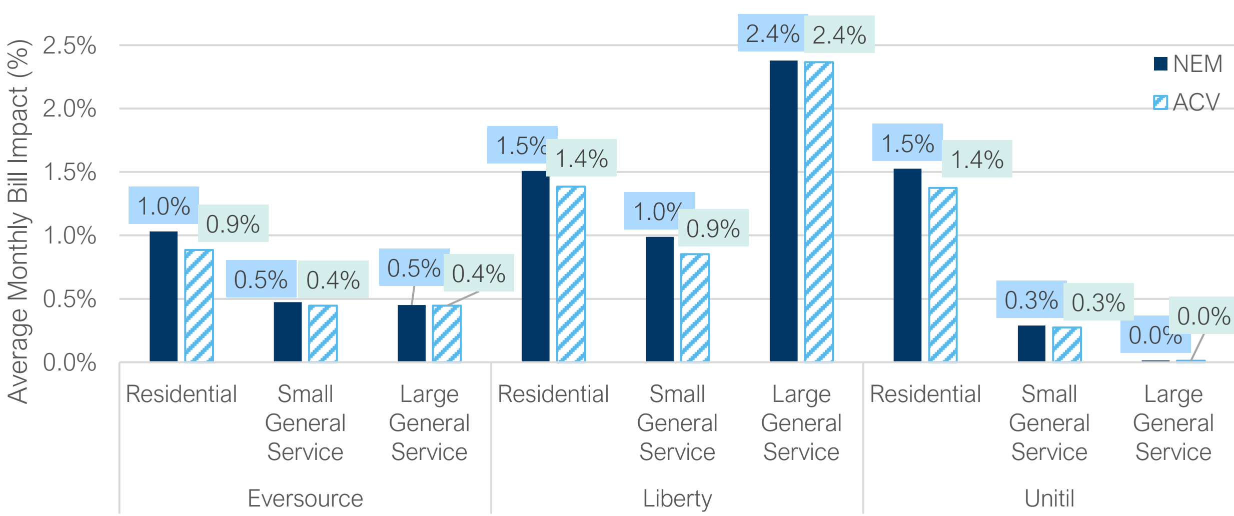
Figure 35. Average Monthly Bill Impact for DG Customer Under NEM and ACV Scenarios (2021-2035)(Relative to no-DG Scenario)[78]



Non-DG Customers

Differences in monthly bills for non-DG customers are insignificant under the ACV Tariff scenario relative to the NEM Tariff scenario. As described above, the differences are primarily observed in residential rate classes that tend to have a higher proportion of net exports, where non-DG customers would benefit from lower rate impacts under the ACV tariff as compared to the NEM scenario, thereby leading to a corresponding reduction in bill impacts.

Figure 36. Average Monthly Bill Impact for Non-DG Customer (2021-2035)(Relative to no-DG Scenario)[79]

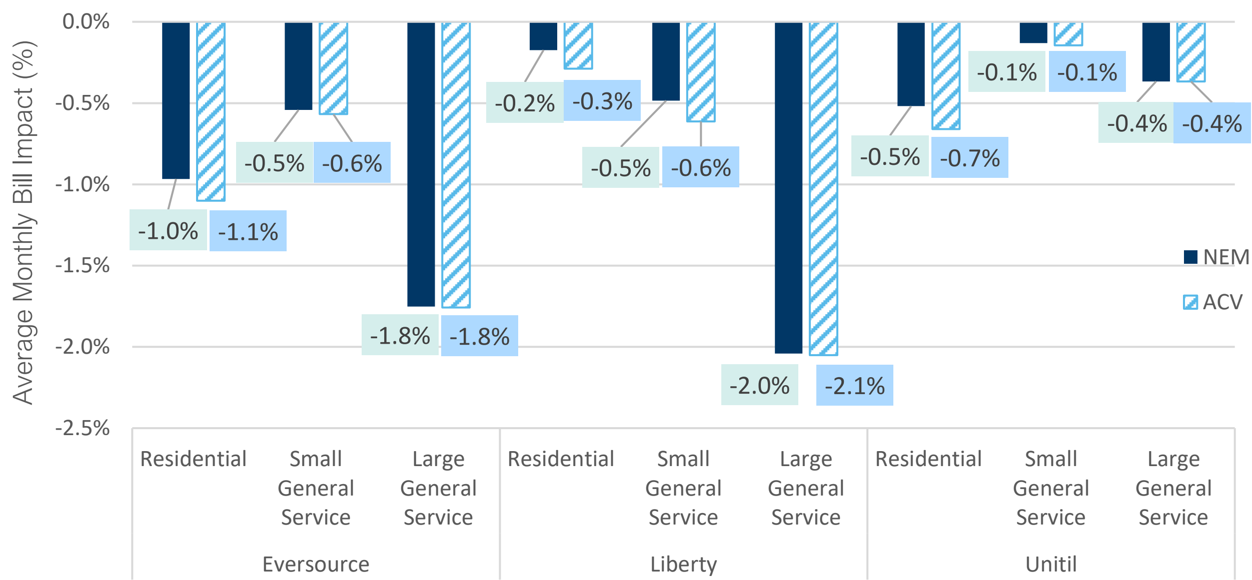


[78] Averaged across the study period
[79] ibid

Average Customers

In assessing the bill impacts for an average utility customer under the ACV Tariff scenario relative to the NEM Tariff scenario, we observe insignificant differences in monthly bills for customers across most utilities and rate classes, with slight bill reductions observed for residential and small commercial classes. The impacts and corresponding magnitude of the differences are largely driven by the magnitude of the net exports within a customer class.

Figure 37. Average Monthly Bill Impact for Average Utility Customer (2021-2035)(Relative to no-DG Scenario)[80]



[80] Averaged across the study period

4 Key Findings

Key Findings

In New Hampshire, DERs are forecasted to provide a total net avoided cost value of **$0.11 to $0.18 per kWh energy produced in 2021** (Figure 38) and **$0.10 to $0.23 per kWh produced in 2035** (Figure 39), varying by DER system type.

The total avoided cost value stack value decreases over the study period for solar-only systems, primarily as a result of decreasing energy avoided costs. West-facing PV systems provide 5-10% greater avoided cost value overall, although currently in New Hampshire south-facing systems are most commonly installed because of production incentives embedded in the current NEM Tariff structure.

Net-metered DER value *increases* over time for solar paired with storage and for micro hydro, as a result of the ability of those systems to generate greater T&D avoided costs, which are assumed to increase over the study period. If the full social cost of environmental externalities (CO_2, NO_x) is considered, the value of net-metered DERs increases by 20%-45%, varying by year and by DG system type.

Figure 38. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System Type, 2021 (2021$)

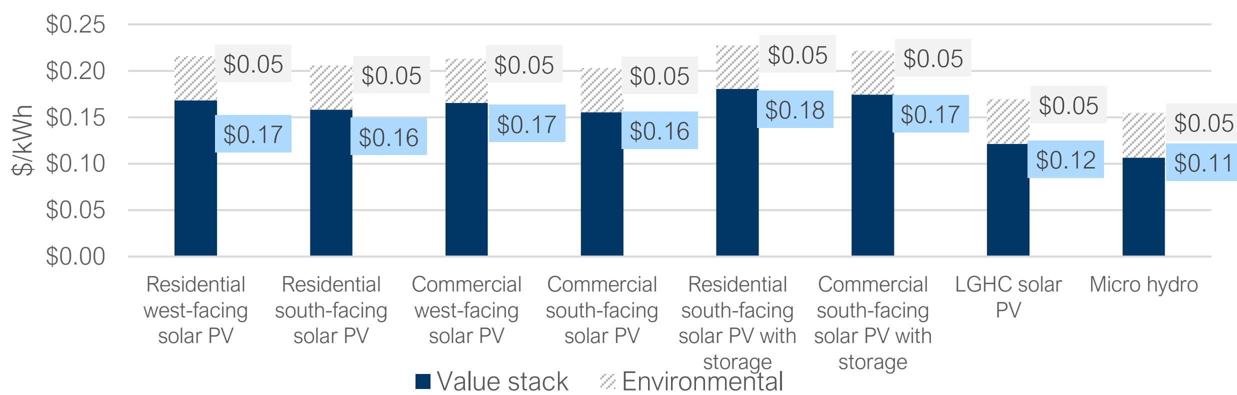
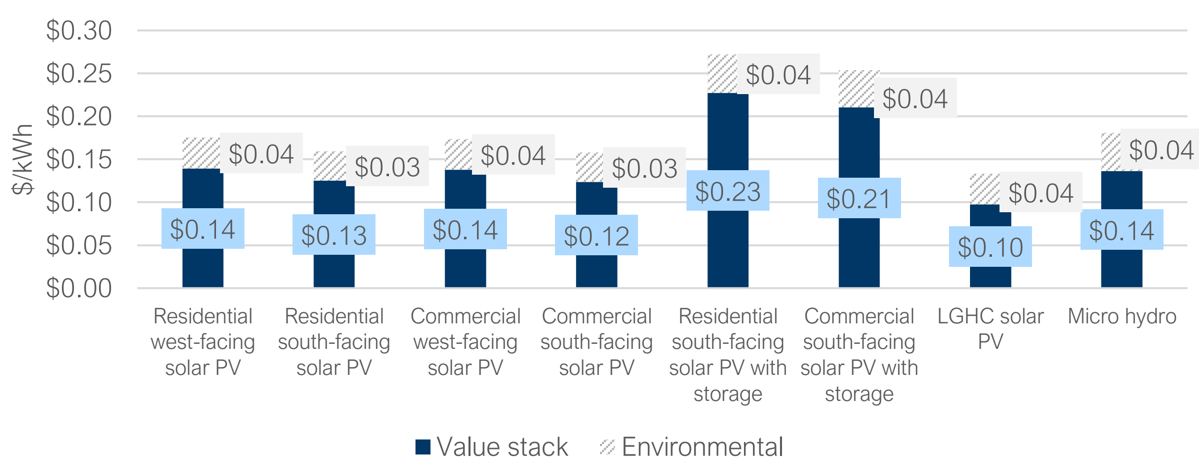


Figure 39. Average Annual Value Stack with Environmental Externalities Sensitivity by DG System, 2035 (2021$)



Avoided cost values may change as a result of increasing system loads and would be different were

DERs to participate in the regional wholesale energy or capacity markets. The impacts of those factors were assessed through the high load growth scenarios (HLGS) and the market resource value scenario (MRVS), respectively. The changes in avoided cost values from the baseline value stack for those scenarios are shown for 2021 in Figure 40 and for 2035 in Figure 41 below.

Increased loads under high load conditions, reflecting increased building and transportation electrification, have minimal impacts on the value of DERs in 2021 (less than 1% difference). In 2035, increased loads drive 2.8% to 5.3% higher values than the baseline value stack, varying by DG system type. The environmental externalities avoided cost sensitivity is also expected to change with loads, increasing in value as loads grow due to changes in the regional generating resource mix.

Net-metered DERs also may participate in the wholesale power markets through aggregations, rather than acting merely as passive resources that generate avoided cost value solely by reducing customer loads. From a utility system perspective, under current ISO-NE market rules, all systems provide greater value by passively reducing load than by participating as aggregated resources in the markets, with the single exception of micro hydro facilities. Micro hydro plants are able to consistently generate energy during the summer and winter peak reliability periods, thereby increasing their value in the capacity market.

Figure 40. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2021 (2021$)

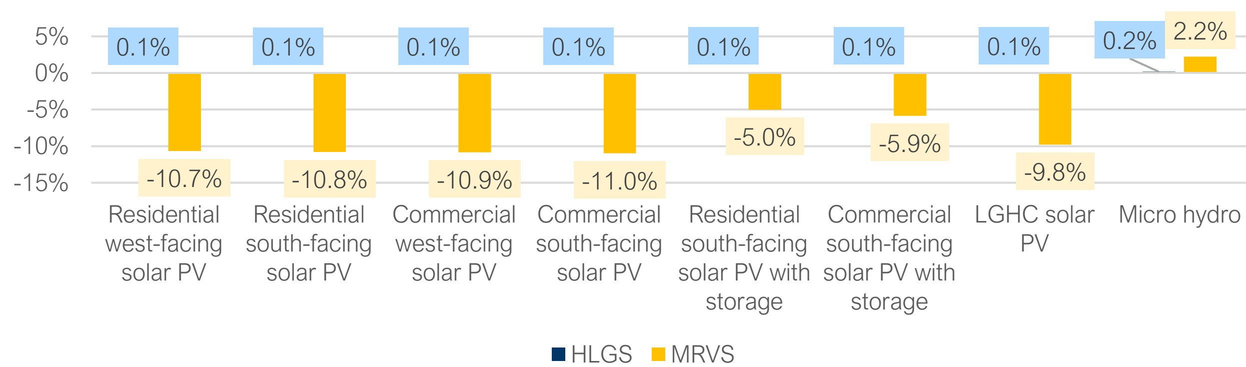
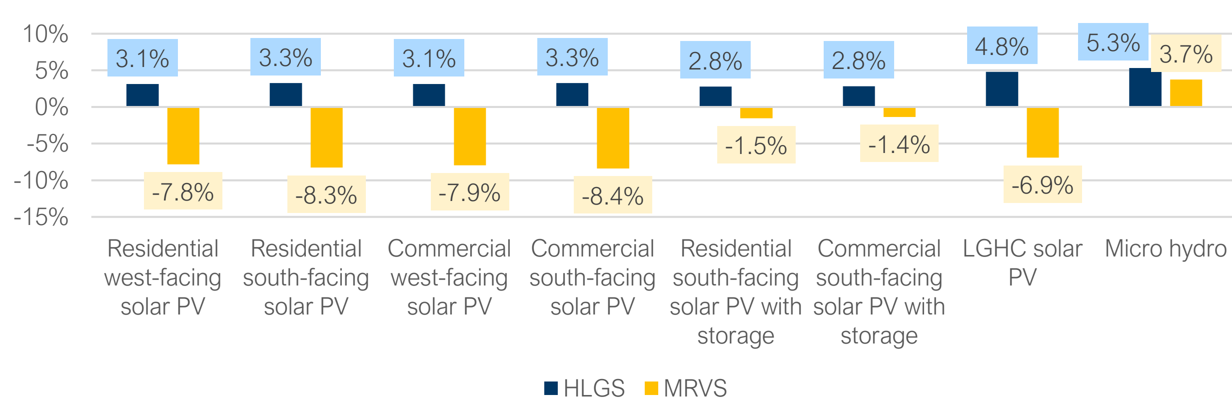


Figure 41. Average Annual Change from Baseline Value Stack Under the HLGS and MRVS, 2035 (2021$)

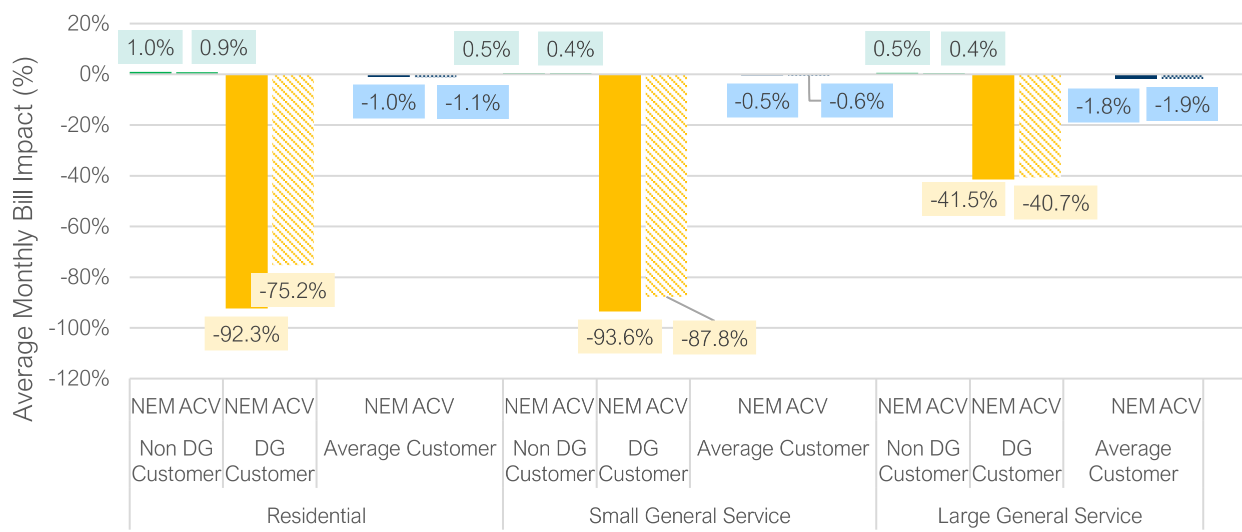


Net-metered DERs are expected to provide additional value beyond what is shown here, notably for those value stack criteria addressed qualitatively in this study: transmission capacity (for non-pool transmission facilities), transmission and distribution system upgrades, distribution grid support services, and resiliency. Additional research and data collection may support quantitative valuation of these criteria in the future.

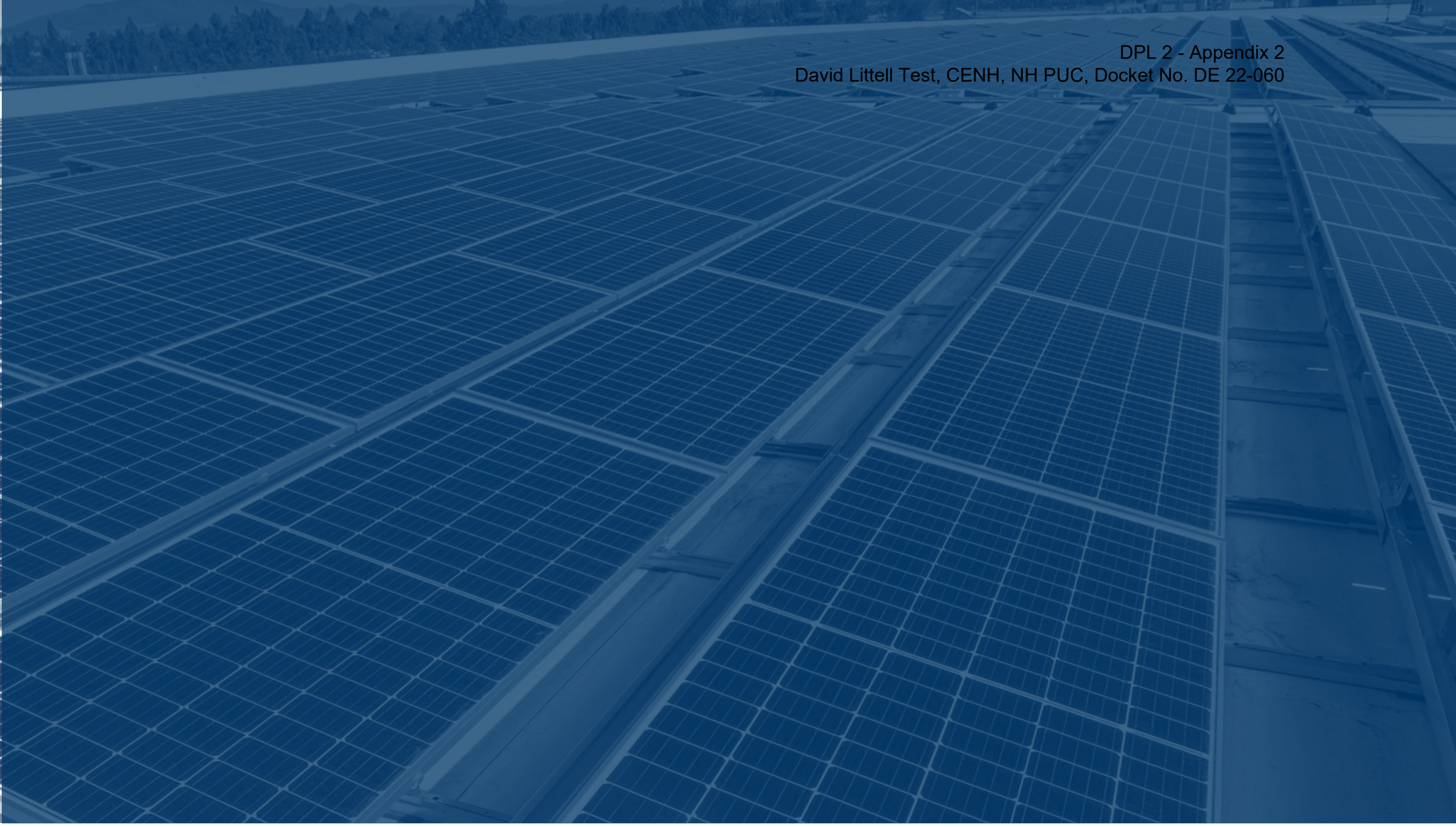
Customer installed costs are included in this study. In the future, these costs may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).[81]

The rate and bill impacts analysis demonstrates that DG will cause rates to increase slightly for all rate classes and across all utilities under the current alternative net metering tariff design. Monthly bills would increase by a small percentage for non-DG customers (1% to 1.5% for residential, 0.3% to 2.6% for commercial), but would decrease by a large percentage for DG customers. The average impact across each customer class, referred to as "average customer" impact, is expected to be a bill reduction. In the alternative, a compensation model based on the avoided cost value stack (i.e., an ACV tariff approach) would slightly reduce rate increases experienced by customers, with virtually the same non-DG customer impacts, but slightly lower bill savings for DG customers, which would be reduced to a greater degree – in particular for residential customers (Figure 42).

Figure 42. Bill Impacts Across Rate Classes in Eversource Territory Under NEM and ACV Scenarios (Relative to no-DG scenario)



[81] NH House Bill 1116. Available online: https://www.gencourt.state.nh.us/bill_status/legacy/bs2016/billText.aspx?sy=2016&id=293&txtFormat=html



New Hampshire Value of Distributed Energy Resources

Appendices

Submitted to:

New Hampshire Department of Energy

New Hampshire Department of Energy

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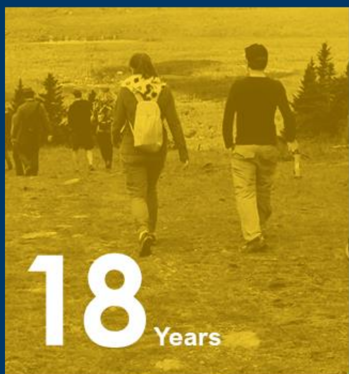
With support from Power Advisory

About Dunsky



Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

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Figure 1. 8,760 Profile for Residential South-Facing Solar PV Array,7.8 kW DC (6.5 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

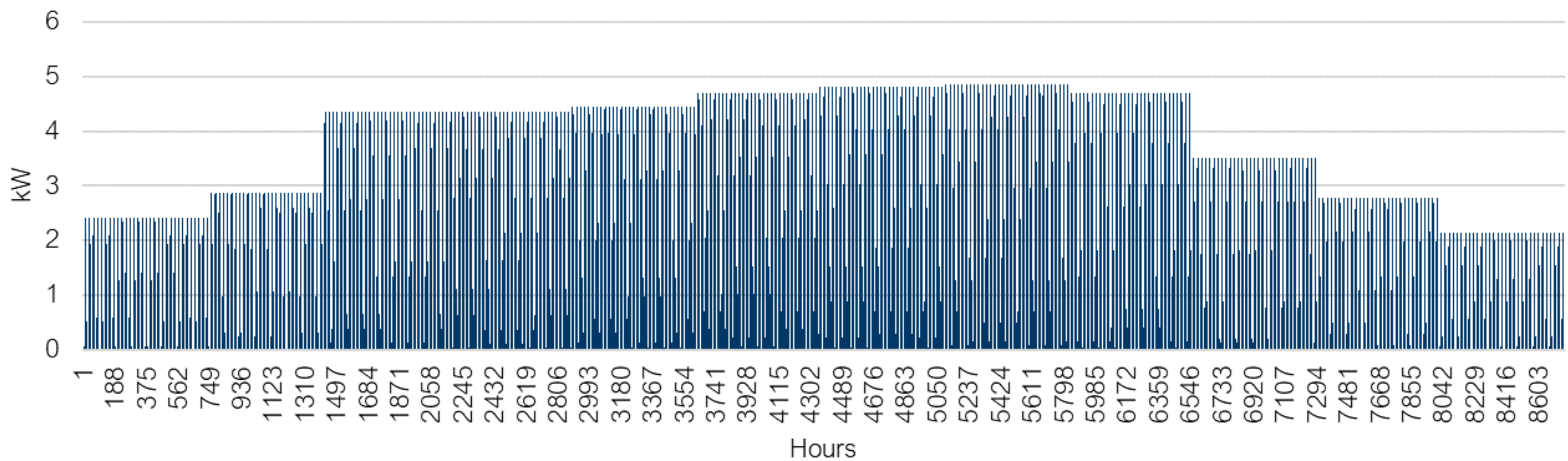


Figure 2. 8,760 Profile for Residential West-Facing Solar PV Array, 7.8 kW DC (6.5 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

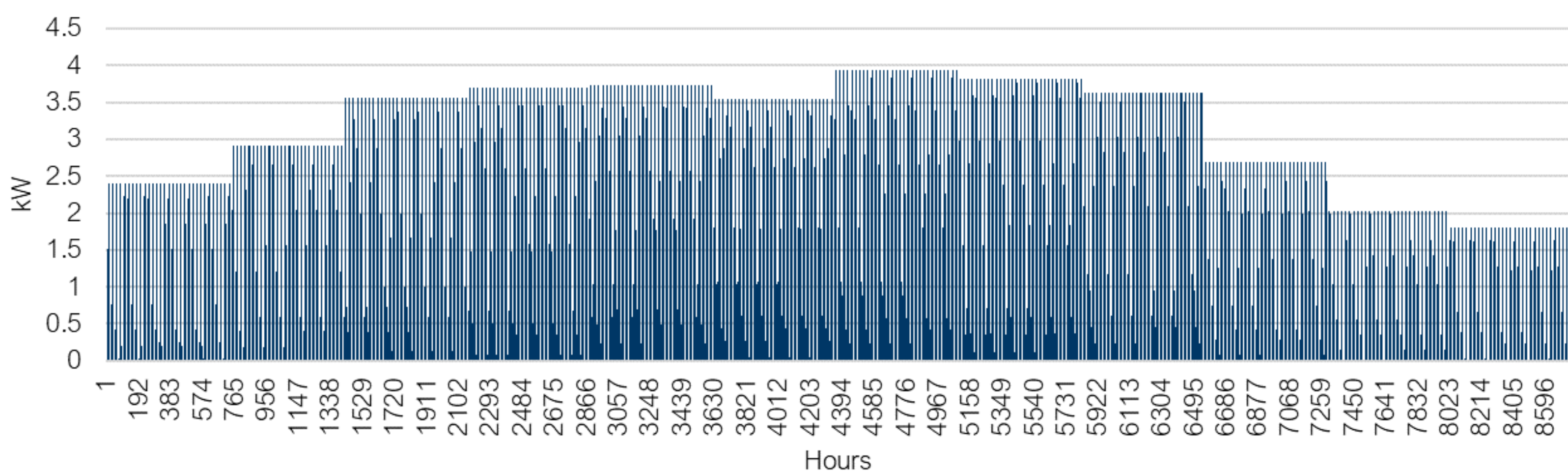


Figure 3. 8,760 Profile for Commercial South-Facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

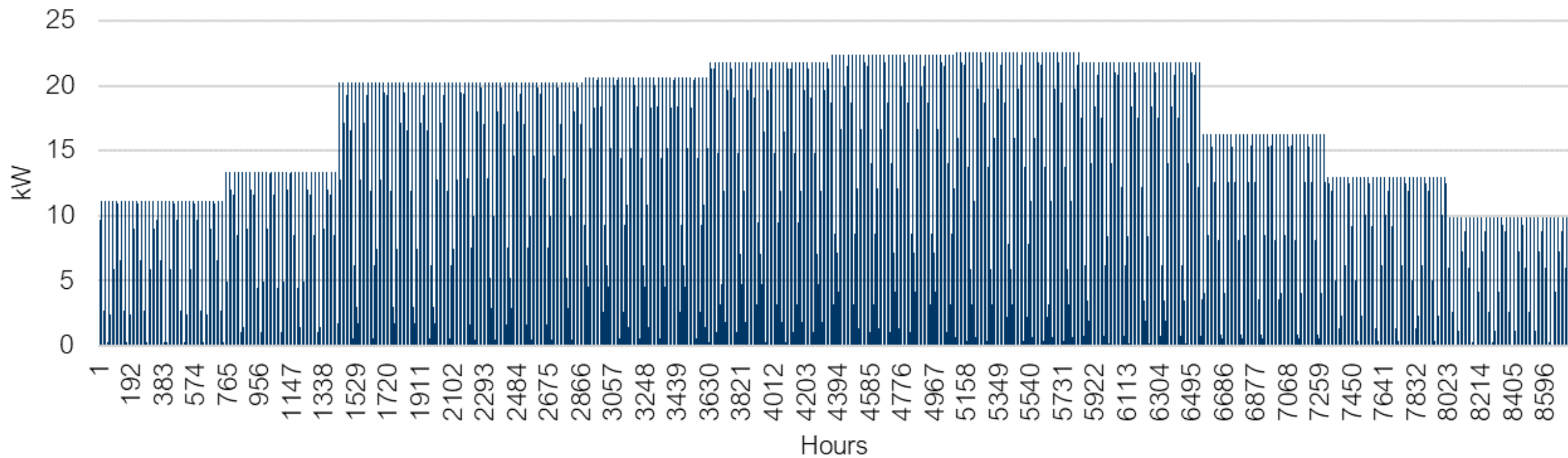


Figure 4. 8,760 Profile for Commercial West-facing Solar PV Array, 36 kW DC (30 kW AC), Azimuth 270, tilt 37.86, assumed location: Concord, New Hampshire

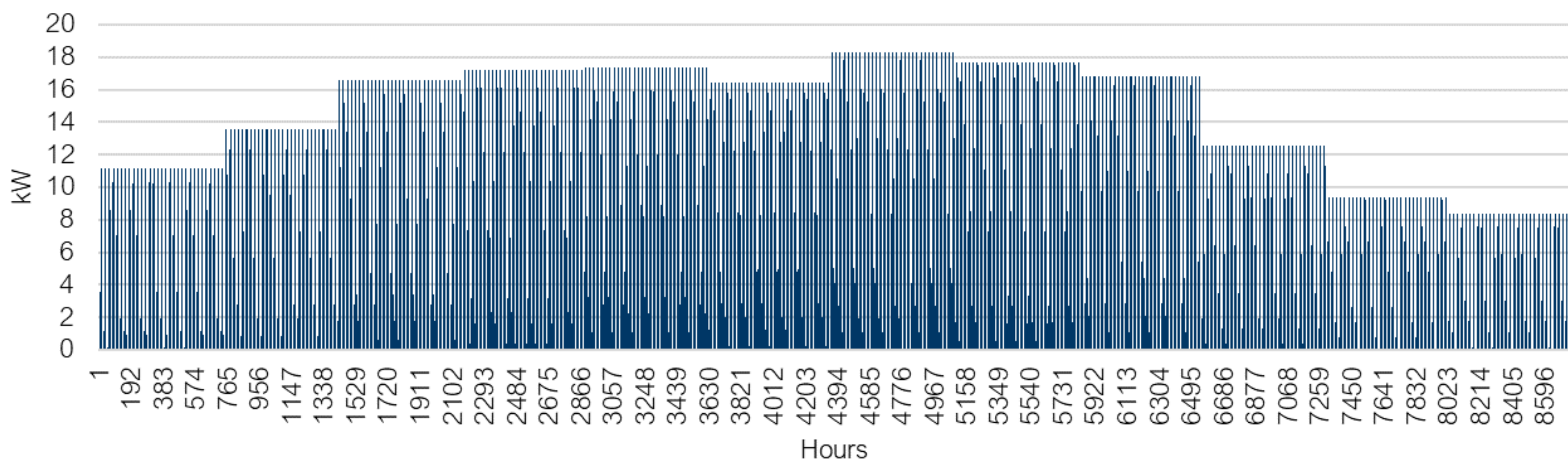


Figure 5. 8,760 Profile for Residential South-Facing Solar PV Array Paired with Storage, 7.8 kW DC (6.5 kW AC), 4-hour duration 10 kWh/2.5kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

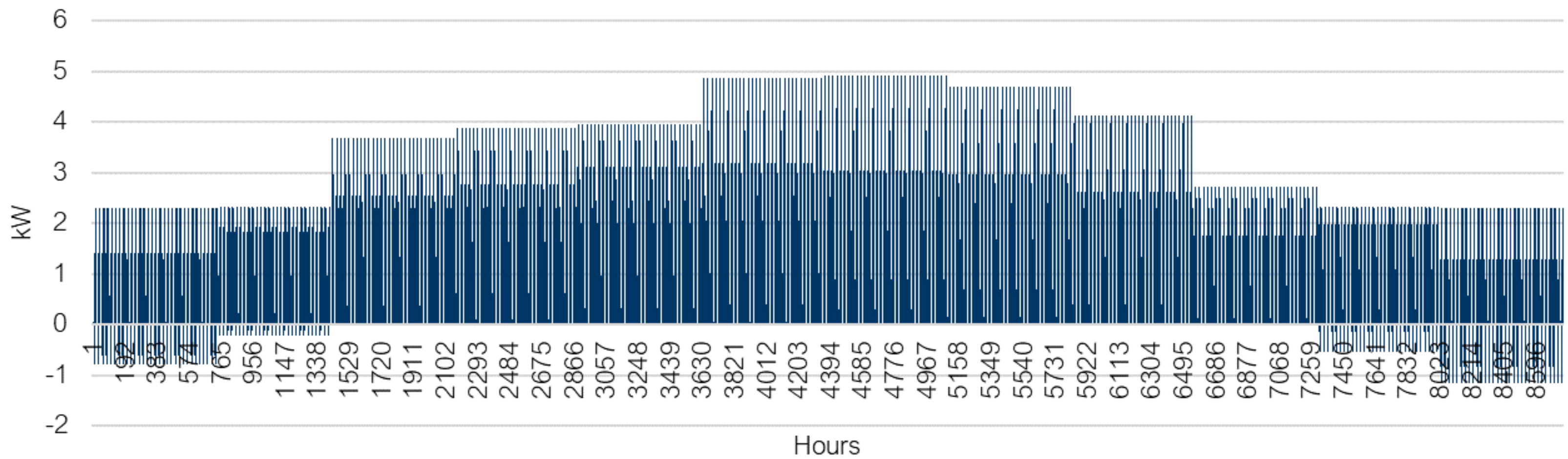


Figure 6. 8,760 Profile for Commercial South-facing Solar Paired with Storage, 36 kW DC Solar (30 kW AC), 4-hour duration 40 kWh/10kW storage system, Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

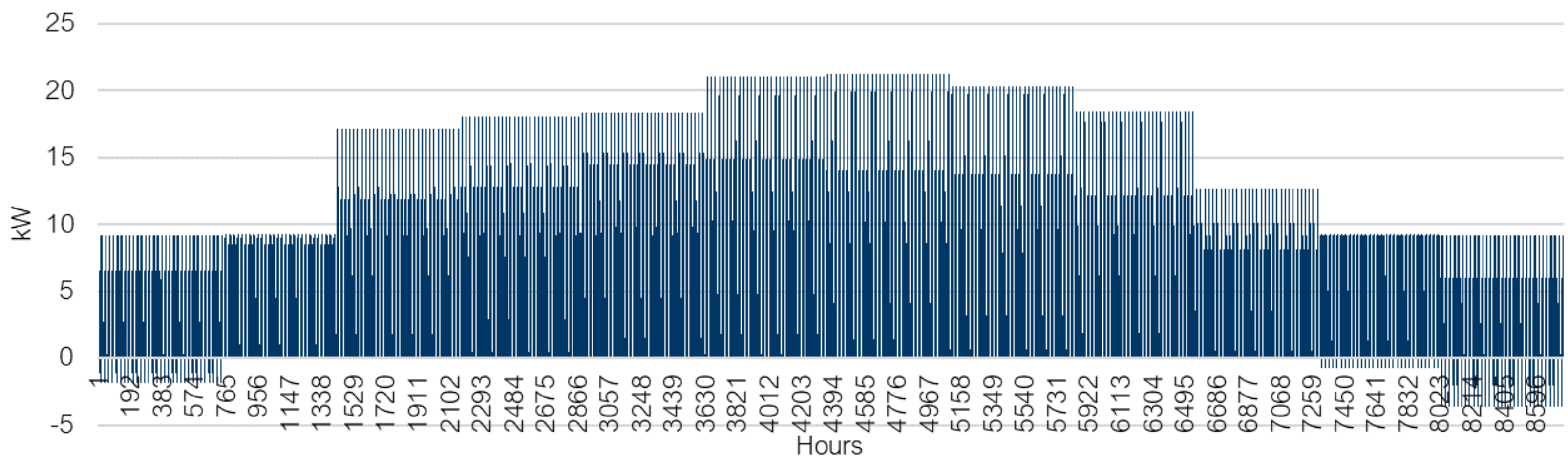


Figure 7. 8,760 Profile for Large Group Host Commercial Solar, 195 kW DC (162 kW AC), Azimuth 180, tilt 37.86, assumed location: Concord, New Hampshire

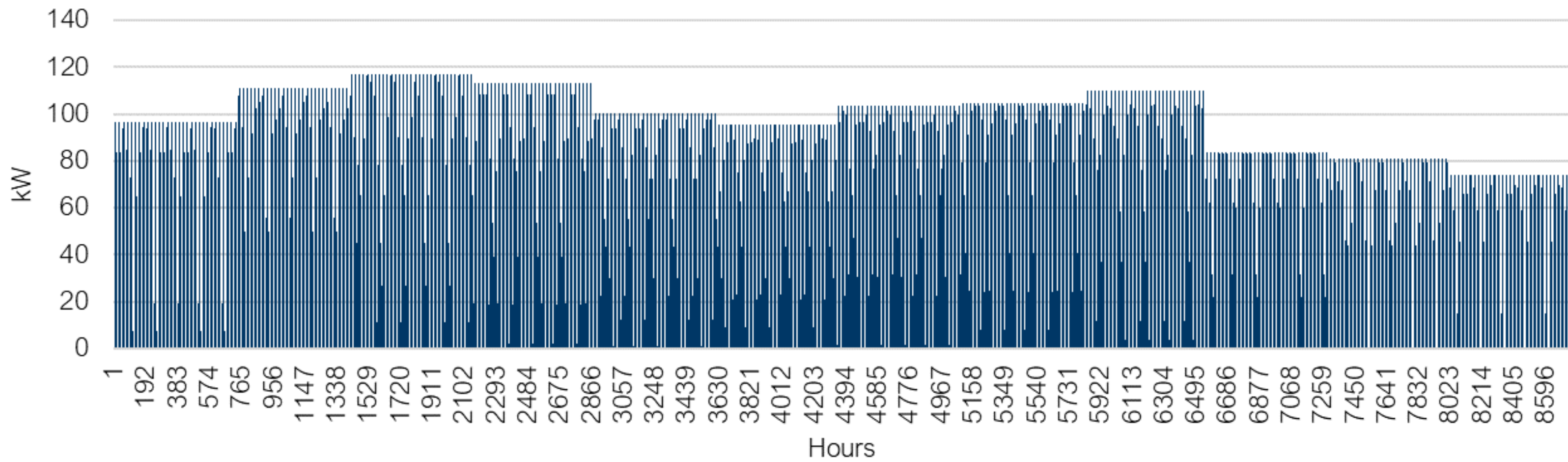
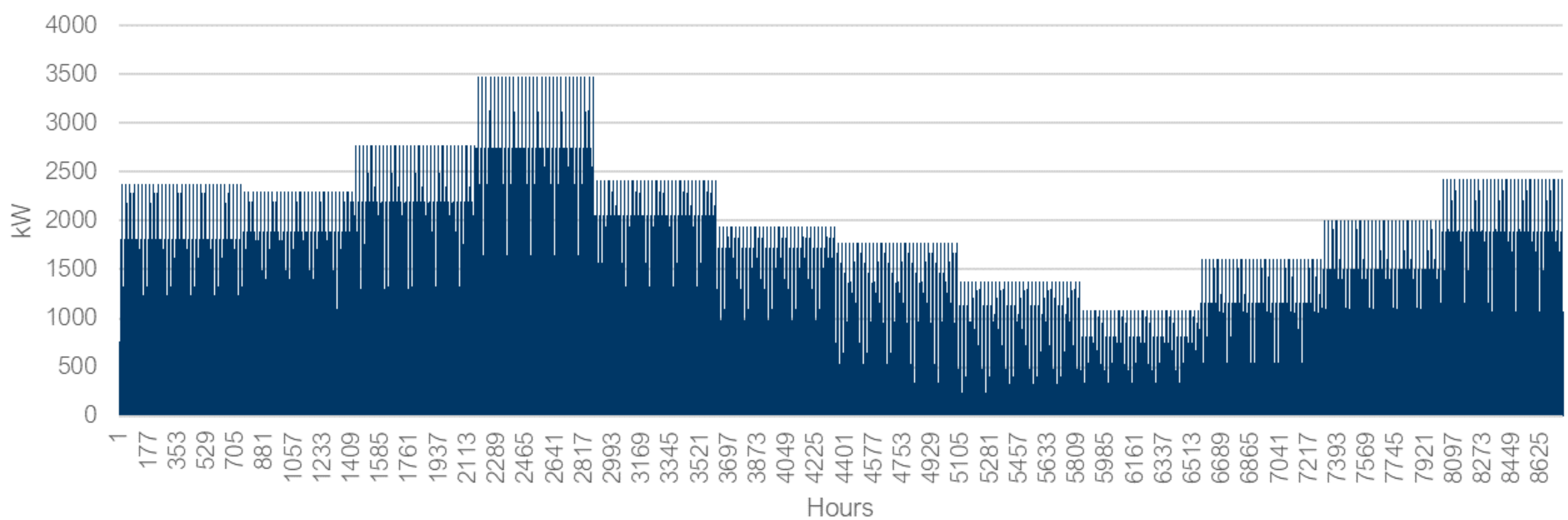


Figure 8. 8,760 Profile for Micro Hydro, 3 MW



B. Results Tables

B.1 Technology-Neutral Value Stack

Table 1. Average Annual Technology-Neutral Value Stack ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.046	0.050	0.045	0.043	0.039	0.037	0.036	0.035	0.036	0.036	0.037	0.037	0.037	0.037	0.039
Transmission Charges	0.020	0.021	0.023	0.024	0.026	0.028	0.030	0.032	0.034	0.036	0.039	0.042	0.045	0.048	0.051
Distribution Capacity	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006
Capacity	0.007	0.006	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.007	0.006
Distribution Line Losses	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.002
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002
DRIPE	0.004	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Environmental Externality	0.049	0.048	0.051	0.055	0.056	0.054	0.051	0.048	0.048	0.045	0.047	0.047	0.048	0.048	0.050
Total – Excluding Environmental	0.102	0.105	0.097	0.097	0.095	0.093	0.096	0.097	0.100	0.103	0.106	0.109	0.113	0.117	0.122
Total – Including Environmental	0.151	0.153	0.149	0.152	0.151	0.148	0.147	0.145	0.148	0.149	0.153	0.157	0.161	0.165	0.171

Table 2. Average Annual Technology-Neutral Value, Minimum Hourly Value, and Maximum Hourly Value ($/kWh) (2021$)

	2021			2025			2030			2035		
	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)
Energy	0.046	0.030	0.082	0.039	0.009	0.077	0.036	-0.008	0.144	0.039	-0.008	0.159
Transmission Charges	0.020	0.000	14.945	0.026	0.000	19.453	0.036	0.000	27.334	0.051	0.000	38.407

Distribution Capacity	0.007	0.000	0.667	0.007	0.000	0.614	0.007	0.000	0.613	0.006	0.000	0.602
Capacity	0.007	0.000	63.000	0.004	0.000	37.000	0.006	0.000	51.000	0.006	0.000	52.000
Distribution Line Losses	0.003	0.000	7.674	0.002	0.000	4.982	0.002	0.000	5.760	0.002	0.000	5.873
RPS	0.004	0.004	0.004	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.000	4.474	0.003	0.000	2.905	0.002	0.000	3.358	0.003	0.000	3.424
Risk Premium	0.005	0.001	1.151	0.004	0.000	1.009	0.004	-0.001	0.644	0.004	-0.001	0.726
Ancillary Services	0.002	0.001	0.005	0.002	0.000	0.005	0.001	-0.001	0.006	0.002	-0.001	0.009
DRIPE	0.004	0.001	4.954	0.005	0.000	7.116	0.005	-0.001	8.037	0.005	-0.001	8.541
Distribution OPEX	0.002	0.000	0.149	0.002	0.000	0.149	0.002	0.000	0.149	0.002	0.000	0.149
Utility Admin	0.000	-0.002	0.000	0.000	-0.002	0.000	0.000	-0.002	0.000	0.000	-0.002	0.000
Environmental Externality	0.049	-0.069	0.350	0.056	-0.008	0.160	0.045	0.000	0.119	0.050	0.000	0.112

B.2 Residential and Commercial Solar PV

Table 3. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.044	0.046	0.040	0.038	0.033	0.030	0.029	0.027	0.027	0.027	0.026	0.026	0.026	0.026	0.028
Transmission Charges	0.035	0.038	0.040	0.036	0.037	0.040	0.038	0.041	0.043	0.046	0.049	0.041	0.035	0.037	0.036
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.028	0.022	0.011	0.015	0.016	0.016	0.019	0.019	0.020	0.022	0.022	0.022	0.023	0.025	0.021
Distribution Line Losses	0.005	0.005	0.003	0.004	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.046	0.047	0.048	0.045	0.040	0.037	0.033	0.032	0.030	0.030	0.030	0.031	0.032	0.034

Total – Excluding Environmental	0.158	0.153	0.136	0.132	0.130	0.127	0.129	0.129	0.131	0.136	0.138	0.129	0.124	0.129	0.125
Total – Including Environmental	0.206	0.200	0.183	0.180	0.176	0.167	0.166	0.162	0.164	0.166	0.168	0.159	0.155	0.161	0.159

Table 4. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.047	0.041	0.039	0.034	0.031	0.030	0.028	0.028	0.028	0.028	0.027	0.027	0.027	0.029
Transmission Charges	0.039	0.041	0.044	0.039	0.041	0.044	0.040	0.043	0.045	0.048	0.051	0.042	0.039	0.041	0.043
Distribution Capacity	0.023	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.020	0.020	0.020	0.019	0.019	0.019
Capacity	0.031	0.025	0.013	0.016	0.018	0.017	0.021	0.021	0.022	0.024	0.024	0.024	0.025	0.028	0.024
Distribution Line Losses	0.006	0.005	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.004
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.047	0.047	0.048	0.046	0.041	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – Excluding Environmental	0.168	0.164	0.145	0.141	0.140	0.138	0.137	0.138	0.141	0.145	0.147	0.137	0.135	0.140	0.139
Total – Including Environmental	0.216	0.210	0.192	0.189	0.186	0.179	0.176	0.173	0.175	0.177	0.179	0.170	0.168	0.174	0.175

Table 35. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.044	0.046	0.040	0.038	0.033	0.030	0.029	0.027	0.027	0.027	0.026	0.026	0.026	0.026	0.028
Transmission Charges	0.035	0.038	0.040	0.036	0.037	0.040	0.038	0.041	0.043	0.046	0.049	0.041	0.035	0.037	0.036
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018

Capacity	0.028	0.022	0.011	0.015	0.016	0.016	0.019	0.019	0.020	0.022	0.022	0.022	0.023	0.025	0.021
Distribution Line Losses	0.004	0.003	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.004	0.003	0.003	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.046	0.047	0.048	0.045	0.040	0.037	0.033	0.032	0.030	0.030	0.030	0.031	0.032	0.034
Total – No Environmental	0.155	0.151	0.134	0.130	0.128	0.126	0.127	0.127	0.130	0.134	0.136	0.127	0.122	0.127	0.123
Total – Including Environmental	0.203	0.198	0.181	0.178	0.174	0.166	0.164	0.160	0.162	0.164	0.166	0.157	0.154	0.159	0.158

Table 46. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.047	0.041	0.039	0.034	0.031	0.030	0.028	0.028	0.028	0.028	0.027	0.027	0.027	0.029
Transmission Charges	0.039	0.041	0.044	0.039	0.041	0.044	0.040	0.043	0.045	0.048	0.051	0.042	0.039	0.041	0.043
Distribution Capacity	0.023	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.021	0.020	0.020	0.020	0.019	0.019	0.019
Capacity	0.031	0.025	0.013	0.016	0.018	0.017	0.021	0.021	0.022	0.024	0.024	0.024	0.025	0.028	0.024
Distribution Line Losses	0.004	0.004	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)

Environmental Externality	0.048	0.047	0.047	0.048	0.046	0.041	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – No Environmental	0.165	0.161	0.143	0.139	0.138	0.136	0.135	0.136	0.139	0.144	0.146	0.136	0.133	0.139	0.138
Total – Including Environmental	0.213	0.208	0.190	0.187	0.184	0.177	0.174	0.171	0.173	0.175	0.178	0.168	0.167	0.173	0.174

Table 7. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.032	-	0.003	0.055	0.044	0.024	-	0.003	0.089	0.080
	7	0.034	-	0.004	0.052	0.041	0.028	-	0.003	0.095	0.086
	8	0.042	-	0.004	0.053	0.041	0.031	-	0.003	0.101	0.091
	9	0.044	-	0.004	0.057	0.045	0.030	-	0.003	0.103	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.045	-	0.004	0.055	0.044	0.021	-	0.002	0.104	0.096
	12	0.045	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.045	-	0.004	0.054	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.157	0.057	0.045	0.022	-	0.003	0.104	0.095
	15	0.045	-	0.158	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.044	-	0.004	0.058	0.045	0.046	-	0.004	0.113	0.099
	19	0.042	-	0.055	0.055	0.043	0.049	-	0.005	0.116	0.102
	20	0.038	-	0.004	0.053	0.041	0.046	-	0.004	0.116	0.102
	21	0.037	-	0.004	0.056	0.044	0.046	-	1.532	0.119	0.105
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-

	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.034	-	0.003	0.063	0.053	0.030	-	0.003	0.090	0.081
	7	0.034	-	0.003	0.059	0.049	0.036	-	0.003	0.096	0.086
	8	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.103	0.093
	9	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.110	0.100
	10	0.040	-	0.006	0.060	0.049	0.037	-	0.007	0.118	0.108
	11	0.040	-	0.047	0.061	0.050	0.036	-	0.056	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.080	0.130	0.120
	13	0.040	-	0.079	0.074	0.050	0.038	-	0.095	0.142	0.123
	14	0.040	-	0.275	0.062	0.051	0.039	-	0.689	0.138	0.127
	15	0.041	0.685	0.580	0.115	0.050	0.040	0.746	0.283	0.149	0.127
	16	0.041	-	0.114	0.059	0.048	0.043	-	0.137	0.140	0.127
	17	0.041	-	0.111	0.056	0.044	0.052	-	1.239	0.260	0.129
	18	0.042	-	0.088	0.057	0.044	0.059	-	0.107	0.145	0.129
	19	0.042	-	0.061	0.057	0.045	0.066	-	0.076	0.144	0.128
	20	0.041	-	0.011	0.058	0.047	0.062	-	0.014	0.140	0.124
	21	0.041	-	0.004	0.059	0.048	0.056	-	0.005	0.135	0.121
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.034	-	0.003	0.055	0.044	0.042	-	0.004	0.095	0.083
	8	0.042	-	0.004	0.060	0.048	0.049	-	0.005	0.103	0.089
	9	0.042	-	0.004	0.060	0.048	0.048	-	0.005	0.106	0.092
	10	0.041	-	0.004	0.061	0.049	0.042	-	0.004	0.106	0.093
	11	0.041	-	0.004	0.058	0.047	0.041	-	0.004	0.107	0.094
	12	0.040	-	0.004	0.059	0.047	0.042	-	0.004	0.106	0.094
	13	0.040	-	0.004	0.058	0.046	0.043	-	0.004	0.106	0.093
	14	0.040	-	0.004	0.060	0.048	0.044	-	0.004	0.107	0.094

	15	0.039	-	0.004	0.061	0.049	0.043	-	0.004	0.108	0.094
	16	0.038	-	0.004	0.057	0.045	0.046	-	0.004	0.108	0.094
	17	0.037	-	0.328	0.063	0.051	0.049	-	0.005	0.109	0.096
	18	0.036	-	0.006	0.060	0.048	0.049	-	0.005	0.111	0.097
	19	0.036	-	0.004	0.056	0.045	0.049	-	0.005	0.112	0.099
	20	0.036	-	0.004	0.065	0.054	0.048	-	1.694	0.116	0.104
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.057	-	0.005	0.058	0.041	0.076	-	0.007	0.114	0.094
	8	0.064	-	0.006	0.068	0.051	0.084	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.128	0.106
	10	0.064	-	0.006	0.071	0.054	0.071	-	0.007	0.128	0.108
	11	0.064	-	0.006	0.070	0.053	0.067	-	0.006	0.127	0.107
	12	0.064	-	0.006	0.073	0.055	0.066	-	0.006	0.126	0.106
	13	0.064	-	0.006	0.072	0.055	0.066	-	0.006	0.124	0.104
	14	0.063	-	0.006	0.071	0.053	0.067	-	0.006	0.125	0.103
	15	0.063	-	0.006	0.072	0.054	0.068	-	0.006	0.126	0.102
	16	0.062	-	0.006	0.069	0.050	0.078	-	0.007	0.129	0.103
	17	0.062	-	0.006	0.067	0.048	0.094	-	0.008	0.135	0.109
	18	0.064	-	0.006	0.067	0.050	0.098	-	0.009	0.151	0.126
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.3 Residential and Commercial Solar PV Paired with Storage

Table 8. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.046	0.041	0.039	0.035	0.033	0.032	0.031	0.032	0.032	0.032	0.032	0.032	0.033	0.034
Transmission Charges	0.055	0.058	0.062	0.063	0.072	0.076	0.077	0.082	0.087	0.093	0.099	0.100	0.106	0.113	0.125
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.030	0.024	0.012	0.016	0.017	0.017	0.021	0.020	0.021	0.023	0.023	0.023	0.024	0.027	0.023
Distribution Line Losses	0.005	0.005	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.005	0.005
RPS	0.004	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004	0.004	0.004
Risk Premium	0.004	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.007	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.008	0.008	0.008
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.047	0.046	0.041	0.047	0.049	0.048	0.045	0.044	0.044	0.041	0.042	0.042	0.042	0.044	0.045
Total – Excluding Environmental	0.181	0.177	0.160	0.163	0.169	0.169	0.173	0.178	0.184	0.192	0.200	0.201	0.207	0.218	0.227
Total – Including Environmental	0.228	0.223	0.202	0.209	0.218	0.217	0.218	0.221	0.228	0.232	0.241	0.243	0.250	0.261	0.272

Table 9. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.045	0.046	0.041	0.039	0.035	0.032	0.031	0.031	0.031	0.031	0.032	0.031	0.032	0.032	0.033
Transmission Charges	0.052	0.055	0.059	0.059	0.067	0.071	0.071	0.076	0.081	0.086	0.092	0.092	0.095	0.101	0.112
Distribution Capacity	0.021	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.019	0.018	0.018	0.018	0.018	0.018	0.018
Capacity	0.029	0.024	0.012	0.016	0.017	0.016	0.020	0.020	0.021	0.023	0.023	0.023	0.024	0.027	0.023
Distribution Line Losses	0.004	0.004	0.002	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.003

RPS	0.003	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Transmission Line Losses	0.005	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.004	0.004	0.004
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.047	0.046	0.042	0.047	0.048	0.047	0.044	0.042	0.042	0.039	0.040	0.041	0.041	0.042	0.043
Total – Excluding Environmental	0.174	0.171	0.154	0.156	0.161	0.161	0.165	0.169	0.174	0.182	0.189	0.188	0.193	0.203	0.210
Total – Including Environmental	0.222	0.217	0.197	0.203	0.210	0.208	0.209	0.211	0.217	0.221	0.229	0.229	0.234	0.245	0.254

Table 10. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.032	-	0.003	0.055	0.044	0.024	-	0.003	0.089	0.080
	7	0.034	-	0.004	0.052	0.041	0.028	-	0.003	0.095	0.086
	8	0.042	-	0.004	0.053	0.041	0.031	-	0.003	0.101	0.091
	9	0.044	-	0.004	0.057	0.045	0.030	-	0.003	0.103	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.044	-	0.004	0.055	0.044	0.021	-	0.002	0.104	0.096
	12	0.045	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.045	-	0.004	0.054	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.160	0.057	0.045	0.022	-	0.003	0.104	0.095
	15	0.045	-	0.158	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.046	-	0.004	0.059	0.046	0.048	-	0.005	0.114	0.099
	19	0.046	-	0.142	0.058	0.045	0.054	-	0.005	0.121	0.105
	20	0.046	-	0.004	0.055	0.041	0.055	-	0.508	0.124	0.108

	21	0.046	-	0.004	0.060	0.046	0.055	-	1.034	0.122	0.107
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.034	-	0.003	0.063	0.053	0.030	-	0.003	0.090	0.081
	7	0.034	-	0.003	0.059	0.049	0.036	-	0.003	0.096	0.086
	8	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.103	0.093
	9	0.039	-	0.004	0.060	0.049	0.040	-	0.004	0.110	0.100
	10	0.040	-	0.006	0.060	0.049	0.037	-	0.007	0.118	0.108
	11	0.040	-	0.047	0.061	0.050	0.036	-	0.056	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.080	0.130	0.120
	13	0.040	-	0.080	0.074	0.050	0.038	-	0.097	0.142	0.123
	14	0.040	-	0.278	0.062	0.051	0.039	-	0.696	0.138	0.127
	15	0.041	0.685	0.580	0.115	0.050	0.040	0.746	0.283	0.149	0.127
	16	0.041	-	0.114	0.059	0.048	0.043	-	0.137	0.140	0.127
	17	0.041	-	0.112	0.056	0.044	0.052	-	1.249	0.264	0.129
	18	0.042	-	0.090	0.057	0.045	0.060	-	0.109	0.146	0.129
	19	0.042	-	0.066	0.057	0.045	0.067	-	0.081	0.146	0.129
	20	0.041	-	0.019	0.059	0.047	0.065	-	0.024	0.144	0.128
	21	0.041	-	0.004	0.059	0.048	0.056	-	0.005	0.135	0.121
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.034	-	0.003	0.055	0.044	0.042	-	0.004	0.095	0.083

	8	0.042	-	0.004	0.060	0.048	0.049	-	0.005	0.103	0.089
	9	0.042	-	0.004	0.060	0.048	0.048	-	0.005	0.106	0.092
	10	0.041	-	0.004	0.061	0.049	0.042	-	0.004	0.106	0.093
	11	0.032	-	0.003	0.059	0.050	0.027	-	0.003	0.098	0.092
	12	0.036	-	0.004	0.059	0.048	0.034	-	0.003	0.103	0.093
	13	0.035	-	0.004	0.056	0.046	0.035	-	0.003	0.103	0.093
	14	0.030	-	0.003	0.059	0.050	0.029	-	0.003	0.101	0.093
	15	0.039	-	0.004	0.061	0.049	0.043	-	0.004	0.108	0.094
	16	0.038	-	0.004	0.057	0.045	0.046	-	0.004	0.108	0.094
	17	0.036	-	0.407	0.062	0.051	0.048	-	0.004	0.109	0.096
	18	0.042	-	0.149	0.062	0.049	0.057	-	0.005	0.120	0.103
	19	0.042	-	0.004	0.059	0.046	0.059	-	0.550	0.125	0.108
	20	0.042	-	0.168	0.062	0.048	0.059	-	1.119	0.128	0.110
	21	0.045	-	0.005	0.062	0.047	0.063	-	0.006	0.127	0.107
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.057	-	0.005	0.058	0.041	0.076	-	0.007	0.114	0.094
	8	0.064	-	0.006	0.068	0.051	0.084	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.128	0.106
	10	0.064	-	0.006	0.071	0.054	0.071	-	0.007	0.128	0.108
	11	0.066	-	0.006	0.075	0.057	0.075	-	0.007	0.129	0.107
	12	0.070	-	0.007	0.082	0.063	0.085	-	0.008	0.130	0.106
	13	0.070	-	0.007	0.082	0.063	0.086	-	0.008	0.129	0.104
	14	0.067	-	0.006	0.079	0.060	0.080	-	0.007	0.128	0.103
	15	0.063	-	0.006	0.072	0.054	0.068	-	0.006	0.126	0.102
	16	0.062	-	0.006	0.069	0.050	0.078	-	0.007	0.129	0.103
	17	0.062	-	0.006	0.067	0.048	0.094	-	0.008	0.135	0.109
	18	0.067	-	0.160	0.071	0.051	0.108	-	0.009	0.172	0.142
	19	0.067	-	0.327	0.071	0.051	0.110	-	1.625	0.188	0.158

	20	0.067	-	0.006	0.073	0.053	0.109	-	0.009	0.187	0.157
	21	0.066	-	0.006	0.072	0.052	0.108	-	0.009	0.170	0.141
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.4 Large Group Host Commercial Solar PV

Table 11. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2021 ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.046	0.049	0.043	0.041	0.036	0.033	0.031	0.029	0.029	0.029	0.029	0.028	0.028	0.028	0.030
Transmission Charges	0.024	0.025	0.027	0.024	0.025	0.026	0.024	0.026	0.027	0.029	0.031	0.026	0.023	0.024	0.026
Distribution Capacity	0.014	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.012	0.012	0.012	0.012	0.012
Capacity	0.019	0.015	0.008	0.010	0.011	0.011	0.013	0.013	0.013	0.015	0.015	0.015	0.016	0.017	0.015
Distribution Line Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Line Losses	0.004	0.004	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.003	0.003	0.004	0.003	0.003	0.003	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
Utility Admin	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Environmental Externality	0.048	0.047	0.048	0.050	0.047	0.042	0.039	0.035	0.034	0.032	0.032	0.032	0.033	0.034	0.036
Total – Excluding Environmental	0.121	0.122	0.108	0.105	0.101	0.099	0.097	0.097	0.098	0.101	0.102	0.096	0.094	0.097	0.097
Total – Including Environmental	0.170	0.169	0.156	0.155	0.148	0.140	0.136	0.132	0.133	0.133	0.134	0.128	0.127	0.131	0.133

Table 12. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2021 ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.

Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.032	-	0.003	0.049	0.038	0.024	-	0.003	0.086	0.076
	6	0.034	-	0.004	0.058	0.047	0.023	-	0.003	0.089	0.079
	7	0.039	-	0.004	0.055	0.043	0.031	-	0.003	0.096	0.086
	8	0.046	-	0.004	0.054	0.042	0.033	-	0.003	0.101	0.091
	9	0.045	-	0.004	0.057	0.045	0.031	-	0.003	0.104	0.094
	10	0.045	-	0.004	0.056	0.044	0.024	-	0.003	0.104	0.096
	11	0.046	-	0.004	0.056	0.044	0.021	-	0.002	0.104	0.096
	12	0.046	-	0.004	0.054	0.042	0.022	-	0.003	0.104	0.096
	13	0.046	-	0.004	0.055	0.043	0.022	-	0.003	0.104	0.095
	14	0.045	-	0.155	0.057	0.045	0.023	-	0.003	0.105	0.095
	15	0.045	-	0.159	0.056	0.044	0.023	-	0.003	0.105	0.095
	16	0.045	-	0.004	0.058	0.045	0.029	-	0.003	0.107	0.095
	17	0.045	-	0.004	0.057	0.044	0.040	-	0.004	0.110	0.096
	18	0.044	-	0.004	0.058	0.045	0.046	-	0.004	0.113	0.099
	19	0.038	-	0.004	0.053	0.041	0.045	-	0.004	0.114	0.100
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.034	-	0.003	0.062	0.052	0.028	-	0.003	0.086	0.078
	6	0.034	-	0.003	0.073	0.063	0.036	-	0.003	0.092	0.082
	7	0.034	-	0.003	0.061	0.050	0.038	-	0.004	0.097	0.087
	8	0.039	-	0.004	0.061	0.049	0.041	-	0.004	0.104	0.093
	9	0.039	-	0.004	0.060	0.049	0.041	-	0.004	0.111	0.100
	10	0.040	-	0.007	0.061	0.050	0.038	-	0.007	0.119	0.108
	11	0.040	-	0.049	0.061	0.050	0.036	-	0.058	0.125	0.115
	12	0.040	-	0.067	0.063	0.052	0.037	-	0.081	0.130	0.120
	13	0.040	-	0.083	0.075	0.050	0.038	-	0.099	0.143	0.123

	14	0.040	-	0.279	0.062	0.051	0.040	-	0.697	0.138	0.128
	15	0.041	0.723	0.584	0.118	0.050	0.040	0.787	0.297	0.151	0.128
	16	0.041	-	0.121	0.059	0.048	0.044	-	0.146	0.142	0.128
	17	0.041	-	0.113	0.056	0.044	0.052	-	1.252	0.268	0.129
	18	0.042	-	0.094	0.056	0.044	0.061	-	0.115	0.147	0.130
	19	0.041	-	0.055	0.056	0.044	0.064	-	0.068	0.142	0.126
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.030	-	0.003	0.046	0.036	0.034	-	0.003	0.085	0.075
	7	0.031	-	0.003	0.054	0.043	0.039	-	0.004	0.094	0.083
	8	0.040	-	0.004	0.060	0.048	0.048	-	0.005	0.102	0.088
	9	0.041	-	0.004	0.060	0.048	0.047	-	0.005	0.105	0.092
	10	0.041	-	0.004	0.061	0.049	0.041	-	0.004	0.106	0.093
	11	0.041	-	0.004	0.059	0.046	0.042	-	0.004	0.107	0.094
	12	0.041	-	0.004	0.059	0.047	0.042	-	0.004	0.107	0.094
	13	0.041	-	0.004	0.058	0.046	0.044	-	0.004	0.107	0.094
	14	0.041	-	0.004	0.060	0.048	0.045	-	0.004	0.108	0.094
	15	0.040	-	0.004	0.061	0.049	0.045	-	0.004	0.108	0.094
	16	0.040	-	0.004	0.058	0.046	0.050	-	0.005	0.110	0.094
	17	0.036	-	0.323	0.063	0.051	0.048	-	0.005	0.109	0.095
	18	0.036	-	0.004	0.060	0.049	0.048	-	0.004	0.110	0.098
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	-	-	-	-	-	-	-	-	-	-
	8	0.063	-	0.006	0.068	0.050	0.085	-	0.008	0.123	0.101
	9	0.064	-	0.006	0.069	0.051	0.086	-	0.008	0.129	0.106
	10	0.064	-	0.006	0.071	0.053	0.071	-	0.007	0.128	0.108
	11	0.063	-	0.006	0.070	0.052	0.066	-	0.006	0.127	0.107
	12	0.063	-	0.006	0.072	0.055	0.066	-	0.006	0.126	0.106
	13	0.063	-	0.006	0.072	0.054	0.066	-	0.006	0.124	0.104
	14	0.063	-	0.006	0.071	0.053	0.067	-	0.006	0.125	0.104
	15	0.063	-	0.006	0.073	0.055	0.071	-	0.007	0.127	0.103
	16	0.063	-	0.006	0.072	0.053	0.083	-	0.008	0.131	0.104
	17	0.062	-	0.006	0.066	0.048	0.094	-	0.008	0.135	0.108
	18	-	-	-	-	-	-	-	-	-	-
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

B.5 Micro Hydro

Table 13. Average Annual Avoided Cost Value for Micro Hydro System ($/kWh) (2021$)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.049	0.053	0.047	0.044	0.040	0.038	0.036	0.035	0.036	0.036	0.036	0.036	0.036	0.036	0.037
Transmission Charges	0.028	0.030	0.032	0.035	0.038	0.040	0.043	0.046	0.049	0.052	0.055	0.060	0.065	0.069	0.074
Distribution Capacity	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006	0.006
Capacity	0.006	0.005	0.003	0.003	0.004	0.003	0.004	0.004	0.004	0.005	0.005	0.005	0.005	0.006	0.005

Distribution Line Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
RPS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Transmission Line Losses	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.005	0.005	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Ancillary Services	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
DRIPE	0.004	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)	(0.000)
Environmental Externality	0.048	0.046	0.046	0.050	0.051	0.051	0.046	0.044	0.045	0.041	0.042	0.043	0.042	0.044	0.045
Total – Excluding Environmental	0.107	0.112	0.104	0.105	0.103	0.102	0.104	0.106	0.110	0.113	0.117	0.122	0.126	0.131	0.136
Total – Including Environmental	0.155	0.158	0.150	0.155	0.154	0.152	0.150	0.150	0.155	0.153	0.159	0.165	0.168	0.174	0.181

Table 14. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System ($/kWh) (2021$)

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	0.039	-	0.002	0.056	0.048	0.031	-	0.002	0.090	0.083
	2	0.038	-	0.002	0.058	0.050	0.030	-	0.002	0.087	0.079
	3	0.039	-	0.002	0.052	0.045	0.028	-	0.002	0.084	0.077
	4	0.039	-	0.002	0.052	0.044	0.027	-	0.002	0.083	0.076
	5	0.039	-	0.002	0.049	0.041	0.026	-	0.002	0.084	0.077
	6	0.040	-	0.002	0.055	0.047	0.027	-	0.002	0.088	0.080
	7	0.041	-	0.002	0.052	0.044	0.032	-	0.002	0.094	0.086
	8	0.046	-	0.003	0.050	0.041	0.033	-	0.002	0.098	0.091
	9	0.045	-	0.003	0.053	0.045	0.030	-	0.002	0.100	0.094
	10	0.045	-	0.003	0.052	0.044	0.024	-	0.001	0.101	0.096
	11	0.045	-	0.003	0.051	0.043	0.021	-	0.001	0.101	0.096
	12	0.045	-	0.003	0.049	0.041	0.022	-	0.001	0.101	0.096
	13	0.045	-	0.003	0.050	0.042	0.022	-	0.001	0.100	0.095
	14	0.045	-	0.154	0.053	0.045	0.022	-	0.001	0.101	0.095
	15	0.045	-	0.177	0.052	0.044	0.023	-	0.001	0.102	0.095
	16	0.045	-	0.003	0.053	0.045	0.028	-	0.002	0.104	0.095
	17	0.045	-	0.003	0.053	0.044	0.040	-	0.002	0.107	0.096
	18	0.046	-	0.003	0.055	0.046	0.048	-	0.003	0.111	0.099

	19	0.047	-	0.156	0.054	0.045	0.055	-	0.003	0.118	0.106
	20	0.047	-	0.003	0.051	0.041	0.055	-	0.498	0.121	0.108
	21	0.046	-	0.003	0.056	0.047	0.055	-	1.069	0.119	0.106
	22	0.046	-	0.003	0.052	0.043	0.052	-	0.003	0.111	0.099
	23	0.045	-	0.003	0.051	0.043	0.047	-	0.002	0.102	0.092
	24	0.040	-	0.002	0.052	0.045	0.040	-	0.002	0.096	0.087

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	0.034	-	0.002	0.050	0.045	0.036	-	0.002	0.092	0.086
	2	0.034	-	0.002	0.055	0.049	0.035	-	0.002	0.088	0.082
	3	0.034	-	0.002	0.058	0.052	0.033	-	0.002	0.085	0.079
	4	0.034	-	0.002	0.058	0.052	0.033	-	0.002	0.084	0.078
	5	0.034	-	0.002	0.061	0.055	0.033	-	0.002	0.085	0.079
	6	0.034	-	0.002	0.061	0.055	0.031	-	0.002	0.087	0.081
	7	0.034	-	0.002	0.055	0.048	0.035	-	0.002	0.093	0.086
	8	0.039	-	0.002	0.055	0.049	0.038	-	0.002	0.100	0.093
	9	0.039	-	0.002	0.055	0.048	0.038	-	0.002	0.107	0.100
	10	0.039	-	0.004	0.055	0.049	0.036	-	0.005	0.114	0.107
	11	0.040	-	0.040	0.056	0.050	0.034	-	0.047	0.120	0.114
	12	0.040	-	0.055	0.058	0.052	0.036	-	0.066	0.125	0.119
	13	0.040	-	0.067	0.112	0.050	0.037	-	0.080	0.178	0.121
	14	0.040	-	0.273	0.057	0.050	0.038	-	0.700	0.133	0.125
	15	0.040	0.528	0.469	0.098	0.050	0.039	0.575	0.178	0.142	0.126
	16	0.041	-	0.107	0.055	0.048	0.043	-	0.129	0.136	0.126
	17	0.041	-	0.105	0.052	0.044	0.051	-	1.189	0.237	0.128
	18	0.042	-	0.083	0.052	0.044	0.059	-	0.101	0.142	0.128
	19	0.041	-	0.058	0.053	0.045	0.066	-	0.071	0.141	0.127
	20	0.041	-	0.014	0.055	0.047	0.063	-	0.017	0.139	0.126
	21	0.041	-	0.022	0.056	0.048	0.060	-	0.027	0.138	0.126
	22	0.041	-	0.011	0.056	0.049	0.056	-	0.013	0.126	0.115
	23	0.040	-	0.002	0.056	0.050	0.049	-	0.003	0.108	0.100
	24	0.034	-	0.002	0.053	0.047	0.040	-	0.002	0.097	0.091

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	0.041	-	0.002	0.047	0.038	0.053	-	0.003	0.097	0.083
	2	0.040	-	0.002	0.055	0.046	0.052	-	0.003	0.093	0.079
	3	0.041	-	0.002	0.055	0.046	0.052	-	0.003	0.091	0.077
	4	0.040	-	0.002	0.052	0.043	0.051	-	0.003	0.089	0.076
	5	0.040	-	0.002	0.051	0.043	0.050	-	0.003	0.089	0.076

	6	0.039	-	0.002	0.049	0.041	0.049	-	0.003	0.092	0.079
	7	0.039	-	0.002	0.052	0.044	0.050	-	0.003	0.098	0.085
	8	0.044	-	0.003	0.057	0.048	0.054	-	0.003	0.103	0.090
	9	0.044	-	0.003	0.057	0.048	0.052	-	0.003	0.105	0.093
	10	0.044	-	0.003	0.057	0.048	0.047	-	0.002	0.106	0.094
	11	0.044	-	0.003	0.055	0.046	0.046	-	0.002	0.107	0.094
	12	0.043	-	0.003	0.054	0.046	0.046	-	0.002	0.106	0.094
	13	0.043	-	0.003	0.055	0.046	0.048	-	0.003	0.106	0.094
	14	0.043	-	0.003	0.056	0.047	0.050	-	0.003	0.107	0.094
	15	0.043	-	0.003	0.058	0.048	0.050	-	0.003	0.108	0.094
	16	0.043	-	0.003	0.055	0.046	0.054	-	0.003	0.109	0.094
	17	0.043	-	0.126	0.059	0.050	0.058	-	0.003	0.113	0.098
	18	0.044	-	0.213	0.059	0.050	0.061	-	0.003	0.121	0.106
	19	0.044	-	0.003	0.056	0.046	0.062	-	0.717	0.126	0.110
	20	0.044	-	0.169	0.057	0.048	0.061	-	0.967	0.128	0.112
	21	0.045	-	0.003	0.057	0.047	0.061	-	0.003	0.123	0.107
	22	0.046	-	0.003	0.058	0.048	0.062	-	0.003	0.115	0.099
	23	0.046	-	0.003	0.057	0.047	0.061	-	0.003	0.108	0.092
	24	0.041	-	0.002	0.048	0.038	0.055	-	0.003	0.102	0.088

		2021					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	0.058	-	0.003	0.063	0.050	0.079	-	0.004	0.109	0.090
	2	0.057	-	0.003	0.059	0.045	0.075	-	0.004	0.106	0.087
	3	0.057	-	0.003	0.058	0.045	0.072	-	0.004	0.103	0.085
	4	0.057	-	0.003	0.058	0.045	0.071	-	0.004	0.102	0.084
	5	0.057	-	0.003	0.057	0.044	0.070	-	0.004	0.104	0.085
	6	0.058	-	0.003	0.069	0.055	0.074	-	0.004	0.108	0.088
	7	0.059	-	0.003	0.079	0.065	0.083	-	0.004	0.115	0.094
	8	0.065	-	0.004	0.068	0.053	0.089	-	0.004	0.123	0.102
	9	0.065	-	0.004	0.066	0.052	0.088	-	0.004	0.126	0.106
	10	0.065	-	0.004	0.068	0.054	0.073	-	0.004	0.125	0.108
	11	0.065	-	0.004	0.067	0.054	0.068	-	0.003	0.124	0.107
	12	0.065	-	0.004	0.070	0.056	0.069	-	0.003	0.123	0.106
	13	0.065	-	0.004	0.070	0.056	0.068	-	0.003	0.121	0.104
	14	0.065	-	0.004	0.069	0.056	0.071	-	0.004	0.123	0.103
	15	0.065	-	0.004	0.071	0.057	0.073	-	0.004	0.124	0.102
	16	0.065	-	0.004	0.070	0.055	0.085	-	0.004	0.128	0.104
	17	0.066	-	0.004	0.067	0.052	0.100	-	0.005	0.142	0.116

	18	0.067	-	0.156	0.066	0.051	0.108	-	0.005	0.169	0.142
	19	0.067	-	0.323	0.067	0.051	0.110	-	1.620	0.185	0.158
	20	0.067	-	0.004	0.068	0.053	0.109	-	0.005	0.184	0.157
	21	0.066	-	0.004	0.067	0.052	0.108	-	0.005	0.167	0.141
	22	0.066	-	0.004	0.070	0.055	0.105	-	0.005	0.144	0.119
	23	0.065	-	0.004	0.073	0.058	0.100	-	0.005	0.127	0.102
	24	0.059	-	0.003	0.087	0.073	0.090	-	0.004	0.116	0.094

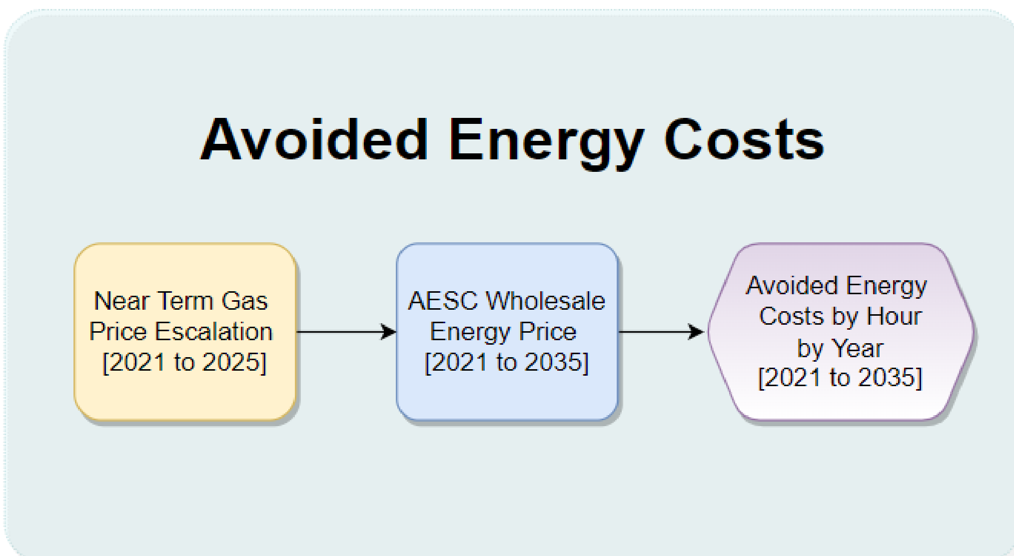
C. Detailed Base Value Stack Methodologies

C.1 Energy

C.1.1 Rationale

This avoided cost criteria represents the cost of energy that would otherwise be generated and procured through the ISO-NE wholesale energy market in the absence of load reductions attributed to distributed generation resources. Hourly LMPs in the New Hampshire zone reflect the displaced variable generation costs associated with the marginal resource(s) in the system and are thus an appropriate measure of the value of avoided energy in the state. The AESC 2021[1] study's hourly wholesale energy avoided cost forecasts are based on detailed modelling, which New England stakeholders vetted, and using this approach is consistent with EE methodology.

C.1.2 Model Map



C.1.3 Avoided Cost Methodology

Step 1: Forecasted Avoided Energy Prices

- Start with the avoided wholesale energy price forecast from the AESC 2021 study, which includes 8760 hourly energy prices for New Hampshire for 2021-2035.[2]

[1] The VDER study uses the latest data from the AESC October 2021 Release (AESC 2021 public files | Powered by Box)
[2] Values from the AESC Counterfactual #2 scenario (and workbook) are used here and throughout the study, as it is deemed the most appropriate of the four counterfactual scenarios included in the AESC 2021 study. The AESC Counterfactual

- Adjust the forecast during the near-term (2021 to 2025) to reflect current and anticipated increases in natural gas prices.[3]

C.1.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic Energy Prices	ISO-NE Day-Ahead Pricing Reports by zone
Forecasted Energy Prices	AESC 2021 study (Counterfactual #2)[4]
Updated Natural Gas Prices	NYMEX Futures for Henry Hub

Assumptions and Notes

- Embedded environmental compliance costs – RGGI cap and trade and SO_2– are included in avoided energy costs.
- Transmission line losses (beyond losses embedded in LMPs), distribution line losses, and the wholesale risk premium are considered separate avoided cost criteria and are thus not accounted for in the avoided energy methodology.

Scenario #2 includes impacts of energy efficiency, active demand response, transportation electrification, and distributed generation but excludes the impact from building electrification.

[3] The AESC uses NYMEX futures prices for the Henry Hub and historical basis differential between Henry Hub and New England trading hubs to establish its short-term natural gas commodity price forecast. Natural gas prices have increased since the AESC 2021 study was finalized, so we updated the short-term natural gas prices based on more recent Henry Hub futures prices. Specifically, we calculated the market heat rate and multiplied this by the higher natural gas prices to derive the new wholesale energy prices. Data was accessed as of February 2022.

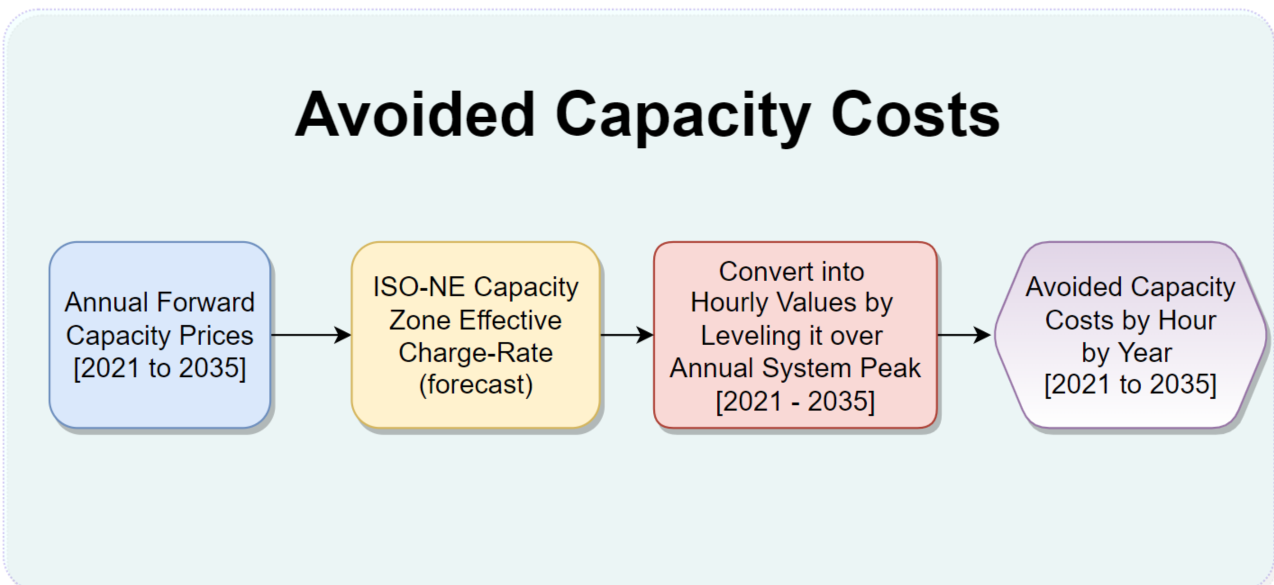
[4] For the NH VDER Study, the ideal avoided cost values would be estimated under a counterfactual scenario that includes region-wide EE, ADR, BE, and transportation electrification impacts along with non-New Hampshire distributed generation impacts. This scenario, unfortunately, is not readily available. However, in lieu of such a scenario, the most appropriate set of AESC avoided costs to utilize for the NH VDER Study is the ones emanating from Counterfactual #2 as this scenario is likely to be most representative of a scenario that includes all demand-side resource impacts sans New Hampshire DG impacts. This is because Counterfactual #2 only excludes the impacts of BE, which is expected to have the smallest influence on avoided costs of importance to the NH VDER study relative to EE and ADR.

C.2 Capacity

C.2.1 Rationale

The VDER Study is primarily focused on estimating the avoided cost impacts from distributed energy resources on New Hampshire regulated load-serving entities. The avoided capacity cost criterion represents the cost of generation capacity that would otherwise be procured through the ISO-NE Forward Capacity Market (FCM). Since individual behind-the-meter distributed generation resources do not qualify for or participate in the FCM[5], these resources provide indirect benefits by reducing ISO-NE peak demand – to the extent that DG production is coincident with system peak – and thus the amount of generation capacity that is procured through the market. From the utility perspective, if customer-sited distributed energy resources reduce utility load during the annual coincident peak hour, the capacity prices assessed on New Hampshire's utilities are reduced, resulting in an in-state avoided cost. In other words, avoidance or reduction of capacity market charges is the basis for the avoided cost calculations, to the extent that DG reduces utilities' peak hourly load in a given year.

C.2.2 Model Map



C.2.3 Avoided Cost Methodology

Step 1: Establish Annual Effective Cleared Capacity Prices (2021-2035)

- We start with the cleared capacity price forecast (2021 to 2035) from the AESC 2021 study and multiply the forecast prices by 1 + the reserve margin (%0.[6] To account for the actual capacity

[5] FERC Order No. 2222 will remove the barriers for aggregated DERs from competing on a level playing field in the organized capacity, energy and ancillary services markets run by regional grid operators.

[6] When establishing market-wide capacity needs, ISO-NE includes a planning reserve margin. This margin provides a buffer, ensuring that there will be adequate capacity should system peak demand be greater than forecasted need. AESC estimates the planning reserve margin to be 14.2% based on actual results from recent auctions. The forecast FCA prices are

charges assessed on utilities, the cleared capacity prices are adjusted using the most recent differential between the FCM Regional Net Clearing Price and the Effective Charge-Rate short-term forecast.[7] The result is the effective cleared capacity prices from 2021 to 2035.

Step 2: Distribute Annual Avoided Capacity Values by Hour

- Identify the ISO-NE's system peak hour by year and forecast any expected shift (due to renewables and increases in beneficial electrification) from 2021 to 2035. Each system year's effective cleared capacity market costs are then distributed over the ISO-NE's annual system peak hour to generate hourly avoided cost values.

C.2.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic Capacity Prices	ISO-NE FCM annual auction results by zone
Forecasted Capacity Prices	AESC 2021 study
Reserve Margin	AESC 2021 study (14.2%)
EffectiveCharge-Rate (by zone)	ISO-NE FCM Net Regional Clearing Price and Effective Charge-Rate Forecast.

Assumptions and Notes: Transmission and distribution line losses and the wholesale risk premium are considered separate avoided cost criteria and are thus not accounted for in the avoided capacity methodology.

multiplied by 1 + the planning reserve margin (114.2%) because each MW that is reduced using DERs *also* reduces the planning reserve margin requirement. So, for example, a 1 MW reduction from DERs results in a 1.142 MW reduction in capacity that must be met through the FCA. The avoided costs are increased to represent the value of each MW reduction, accounting for the planning reserve impacts.

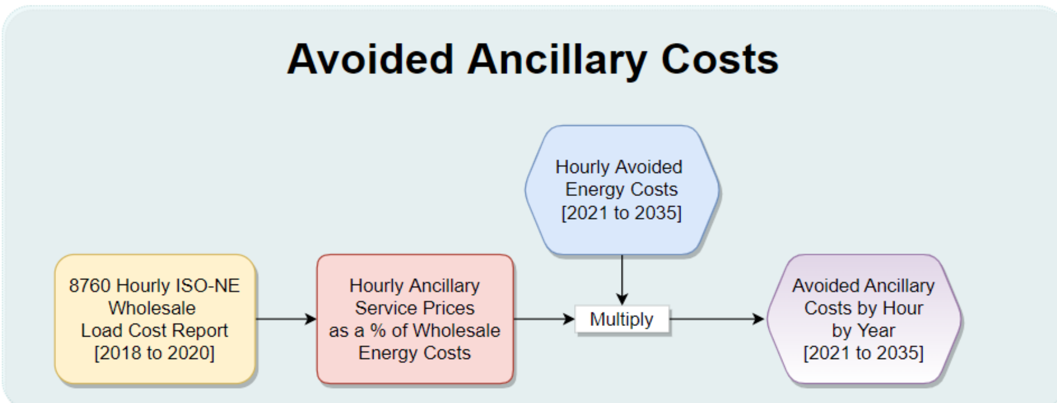
[7] Because Forward Capacity Auctions are held three years in advance, the actual cost of capacity procured on the market at the time that it is needed can vary from the FCA clearing price. The effective charge rate is a factor that is forecasted by ISO-NE which represents the difference between the future-looking auction prices and the actual prices at which resources are procured. Effective charge forecasts are only available on a short-term basis, however. To calculate expected actual capacity prices over the study period, the study team assessed the near-term relationship between the effective charge forecast and the FCA. The team then applied this relationship to the remaining FCA forecast years, considering the planning reserve margin, to estimate actual capacity prices over the study period.

C.3 Ancillary Services and Load Obligation Charges

C.3.1 Rationale

This study is focused on the avoided cost impacts on New Hampshire-regulated electric distribution utilities and the load-serving entities providing electric supply to the utilities' customers. The AESC does not calculate avoided costs for ancillary services and hence was not used as the basis for this methodology. From the utility perspective, if customer-sited distributed energy resources reduce utility load, then ancillary service charges and other load obligation charges assessed on New Hampshire's utilities and LSEs are reduced, resulting in an in-state avoided cost.

C.3.2 Model Map



C.3.3 Avoided Cost Methodology

Step 1: Calculate Historic Hourly Ancillary Service Prices (2018-2020)

- Calculate ancillary service and wholesale load obligation costs[8] as a percentage of hourly energy costs by service or charge.[9]
- For each historic year (2018 to 2020), calculate an hourly ancillary service and load obligation cost as a percentage of wholesale energy cost for each respective hour.
- Average hourly ancillary costs (as a percentage) for each type of ancillary service and load obligation charge across the three historic years to generate an 8760 ancillary avoided cost template.

[8] The ancillary services included are First and Second Contingency, Forward and Real Time Reserves, Regulation, Inadvertent energy, Net Commitment Period Compensation (NCPC), Auction Revenue Rights (ARR) revenues, NEPOOL expenses, etc. – as charged to wholesale load obligations). Ancillary service cost data was obtained from ISO-NE's Wholesale Load Cost reports for the NH zone.
[9] Ancillary service cost data obtained from ISO-NE's Wholesale Load Cost reports for the NH zone.

Step 2: Forecast Hourly Ancillary Service Prices (2021-2035)

- Multiply the 8760 ancillary avoided cost template from Step 1 by the forecasted wholesale energy prices (2021 to 2035) to develop hourly ancillary service price and wholesale load obligation avoided cost projections.

C.3.4 Inputs, Assumptions, and Notes

Inputs

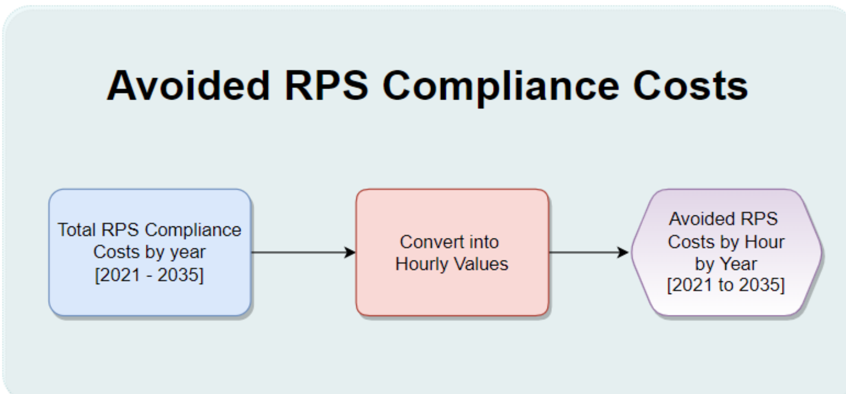
Inputs	Sources
Wholesale Hourly Energy Prices	AESC 2021 study (Counterfactual #2)
Wholesale Ancillary and Load Charges	ISO-NE wholesale monthly reports by zone

C.4 RPS Compliance

C.4.1 Rationale

The AESC Study provides RPS compliance avoided cost forecasts by state, which quantify the avoided costs attributable to reducing the load on which the RPS obligations are assessed. The value of RPS avoided costs is calculated for each sector, accounting for the share of energy produced by DG that is expected to be consumed behind-the-meter and the share expected to be exported back to the grid.[10] Therefore, for this analysis, it is assumed that the avoided RPS compliance costs (per MWh) are equal to the weighted statewide compliance costs across all RPS classes as forecast in the AESC 2021 Study.

C.4.2 Model Map



Overview: The AESC provides RPS compliance avoided cost forecasts by state which summarize the expected cost of meeting RPS obligations

C.4.3 Avoided Cost Methodology

Step 1: Calculate the Total Annual RPS Compliance Costs (2021-2035)

- Sum the RPS compliance costs from the AESC 2021 study for each New Hampshire RPS Class, for each study year (2021 to 2035), under Counterfactual #2.[11] The following RPS classes are included:

RPS Class	Eligibility Notes
Class I	Includes New Non-Thermal
Class I (Thermal)	Thermal Carve out
Class II	New Solar Only
Class III	Existing biomass and methane
Class IV	Existing Small hydro

[10] RPS compliance costs are proportional to retail sales. Reductions in retail sales through behind-the-meter consumption reduces RPS compliance costs, while electricity exported back to the grid does not.
[11] The RPS compliance costs are weighted based on the RPS requirement and expressed as a percentage for each Class.

- Convert to customer sector-specific hourly values by multiplying RPS compliance costs by the behind-the-meter consumption expected for each sector, as outlined in the table below. Apply the avoided cost value to all hours in each respective study year.

Customer-Generator Type	Behind-the-Meter Consumption (% of Total Production) [12]
Residential	38% (hourly netting)
Commercial	24% (hourly netting)
Large Group Host Commercial Solar	0%
Micro Hydro	0%

C.4.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
RPS Compliance Costs (All Classes)	AESC 2021 study (Counterfactual #2)

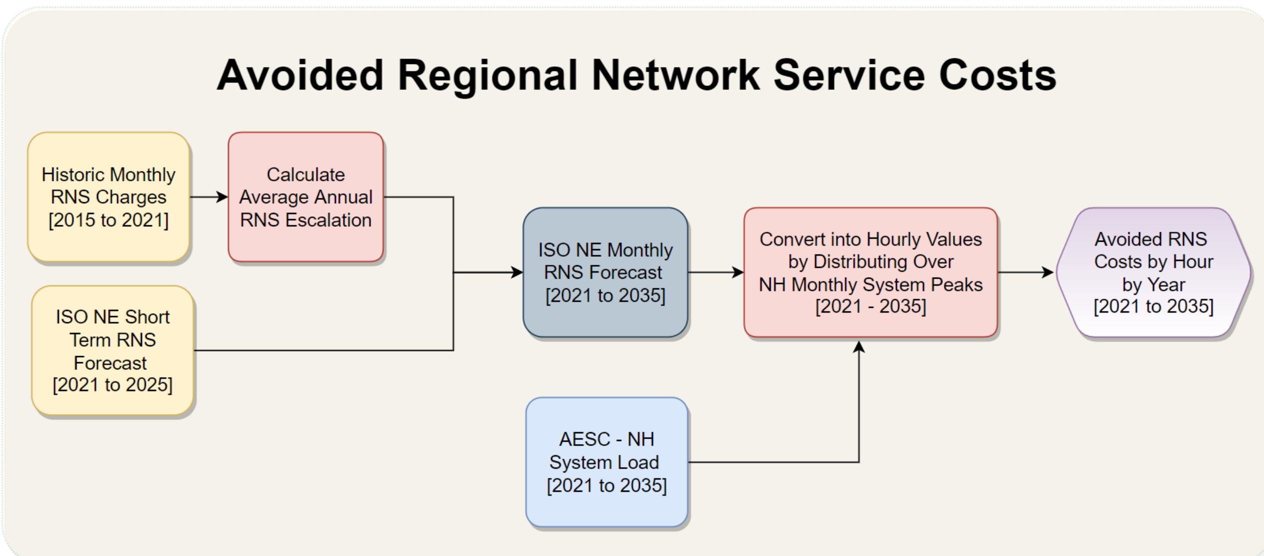
[12] For the purpose of the value stack assessment, we calculated the hourly netting from a south-facing solar PV system then applied this assumption to the west-facing and south-facing solar with storage systems within a given sector. Although the current NEM tariff in New Hampshire uses monthly netting for systems less than 100 kW, hourly netting is an emerging practice used in VDER studies conducted in other jurisdictions given its ability to realize temporal values more granularly.

C.5 Transmission Charges

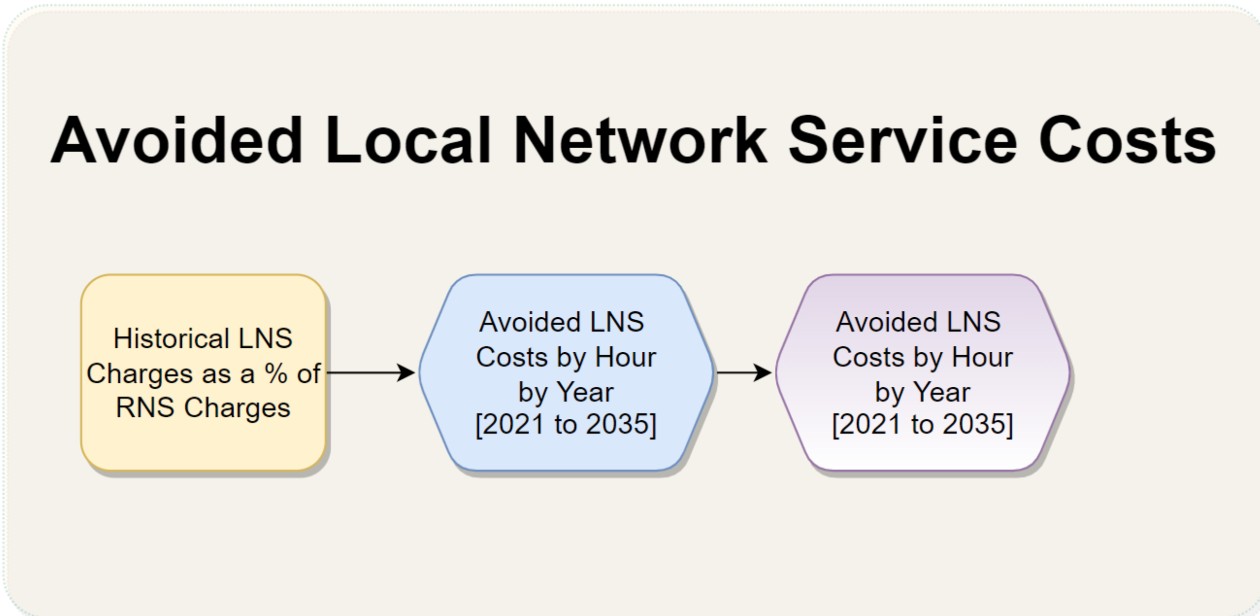
C.5.1 Rationale

RNS and LNS charges are collected to cover the cost of upgrading and maintaining regional bulk transmission infrastructure and localized facilities. Costs are assessed monthly based on a utility's demand that coincides with the peak load hour on the relevant transmission system. Therefore, from a New Hampshire utility perspective, reductions in monthly coincident system peak load attributable to DG resource production will decrease the allocation of RNS and LNS charges assessed to New Hampshire utilities, and thus to ratepayers in the state, representing avoided transmission charges based on DG production. Short-term NEPOOL Reliability Committee/Transmission Committee transmission charge forecasts were found to exceed AESC avoided cost forecasts.[13] Given the discrepancy, these short-term forecasts were used, as described below.

C.5.2 Model Map



[13] The 2021 AESC estimated the PTF avoided cost as $99 per kW-year (2021$). The RNS charge in 2021, as approved by FERC was $140 per kW-year from June 2021 onwards: https://www.iso-ne.com/static-assets/documents/2016/05/rto_bus_prac_sec_2.pdf



Overview: Load cost reports published by ISO-NE used to establish historic monthly RNS and LNS charges in $/kW-month (2016 to 2020).

C.5.3 Avoided Cost Methodology

Step 1: Establish Historic Monthly RNS and LNS Rates (2016-2020)

- Use ISO-NE Load Cost Reports to establish historic monthly RNS and LNS rates for 2016-2020. Use this to calculate historic LNS charges as a portion of historic RNS charges.[14] Include all RNS and LNS cost categories (i.e., infrastructure, reliability, and administrative cost categories) that are allocated based on Monthly Regional Network Load. Adjust rates to $2021 real values for comparison purposes.

Step 2: Establish Projected Monthly RNS and LNS Rates (2021-2035)

- Forecast forward-looking monthly RNS rates using 1) short-term RNS forecasts published by ISO-NE (for near-term study years),[15] 2) the assumption that LNS charges are a fixed percentage of RNS charges, based on historic trends.[16]

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[14] The LNS charges vary considerably from month to month so are a challenge to forecast. As a simplifying approach, we reviewed historic monthly LNS charges as a % of RNS charges over the 2016 to 2020 time frame. On average, LNS charges were 22% of RNS charges during this time frame.
[15] NEPOOL Reliability Committee/Transmission Committee. (2020). RNS Rates: 2020-2024 PTF Forecast. Source: https://www.iso-ne.com/static-assets/documents/2020/08/a02_tc_2020_08_19_rns_5_year_forecast.pptx
[16]Here, LNS charges were assumed to remain constant at 22% of RNS charges. In reality, LNS charges are not a fixed percent of RNS charges and in fact fluctuate from month-to-month – this is a simplifying assumption that uses the average LNS charges as a percent of RNS charges from 2016-2020.

Step 3: Distribute Monthly RNS and LNS Charges by Hour

A) Establish Monthly Peak Load Hours

- Determine each utility's historic monthly Regional Network Load (RNL) – i.e., demand on the New Hampshire transmission network coinciding with the system peak load for each month. Then, based on historic RNL data (over the past 5 years), define the peak hour for each month in the year.

B) Convert Monthly into Hourly Values

- Distribute monthly RNS and LNS charges over the monthly peak hours by multiplying the calculated rates by utility peak contributions across the study year to generate hourly avoided cost values.

Step 4: Establish Hourly Avoided Transmission Charge Costs by Year

- Repeat this process for each forecasted monthly RNS and LNS charge to generate hourly avoided transmission charges for each year of the study period.

C.5.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Historic RNS Charges	ISO-NE Load Cost Reports
Historic LNS Charges	Utility data request; docket filings
Forecasted RNS Rates	NEPOOL Reliability Committee/Transmission Committee RNS Rates: 2020-2024 PTF Forecast[15]
Regional Network Load	ISO-NE RNL Reports[17]

C.6 Transmission Capacity

This criterion was assessed qualitatively. The rationale and the sources used to inform this assessment are included in the body of the report.

C.7 Distribution Capacity

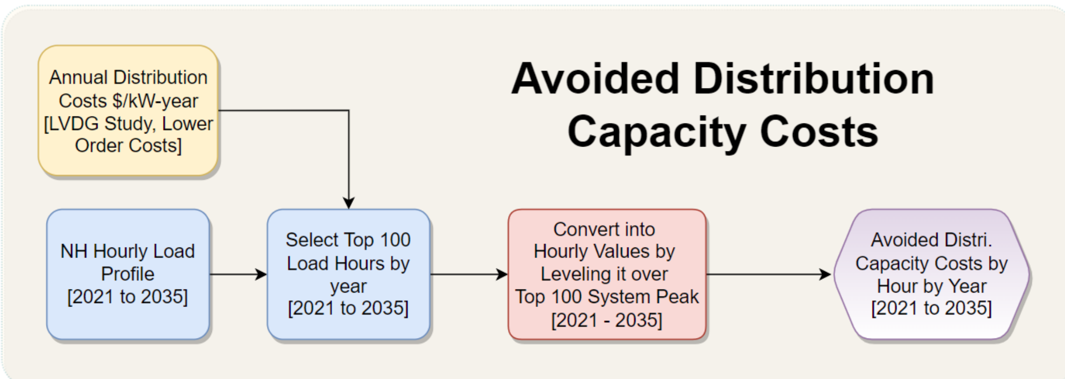
C.7.1 Rationale

Energy produced by net-metered DG has the potential to avoid or defer distribution capacity upgrade costs if it reduces load at hours associated with reliability concerns (i.e., during peak hours that would otherwise drive investments in distribution system upgrades). In connection with the Locational Value

[17] ISO-NE. (2021). Monthly Regional Network Load Cost Report and Historical Regional Network Load Cost Report. Accessible online at: https://www.iso-ne.com/markets-operations/market-performance/load-costs

of Distributed Generation (LVDG) study,[18] New Hampshire's utilities estimated the capital investments that would be required at various substations or circuits as a result of capacity deficiencies based on relevant planning criteria. Beyond those upgrades required to address capacity deficiencies, some investments are also expected to be required to address non-capacity upgrades (e.g., those related to reliability or performance issues), which the LVDG study did not address. Because the capacity-related deficiencies and the related potential avoided costs, reviewed in the LVDG study are highly locational, those costs are not considered in this study, which reviews system-wide avoided costs only.

C.7.2 Model Map



C.7.3 Avoided Cost Methodology

Step 1: Annual Distribution Capacity Costs

- Assess actual and planned distribution-related capital expenditures, by utility, to determine which expenditures are load-related and what components (lower-order and higher-order investments) are included.

- Review utility capital expenditure data and compare it to the LVDG Study results under the base case, which is used to determine which lower-order distribution system investments are not accounted for in that study but could be avoided or deferred as a result of load reductions.

- Use utility data and the LVDG Study to develop an annual per unit ($/kW), system-wide proxy estimate of annual system-wide avoided distribution costs. Use an escalation factor based on inflation to estimate annual distribution capacity costs beyond planned investment needs.[19]

Step 2: Distribute Annual Avoided Distribution Capacity Value by Hour

[18] Guidehouse Inc. (2020). New Hampshire Locational Value of Distributed Generation Study. Accessible online at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/LETTERS-MEMOS-TARIFFS/16-576_2020-08-21_STAFF_LVDG_STUDY_FINAL_RPT.PDF#:~:text=The%20New%20Hampshire%20Public%20Utilities%20Commission%20%28the%20Commission%29,metering%20docket.%20In%20its%20February%202019%20order%2C%201

[19] To the extent possible we used annual avoided cost forecasts from the LVDG study, which are based on a Real Economic Carrying Charge approach. Forecasted lower-order distribution costs were inflation-adjusted.

A) Establish New Hampshire System Load Profiles

- Use New Hampshire zone load profiles in the AESC 2021 study for system load profiles for 2021 through 2035.

B) Establish Distribution of Load During Peak Hours

- Assume distribution system upgrades are driven by reliability concerns associated with the highest distribution peak load hours on the system. Rank the top 100 hours in each year (2021-2035) to select the distribution system peak hours.

- Establish the weighted average of the total sub-set of load during each month/hour pairs. For example, the table below (based on NH 2021 system load) demonstrates that, during the highest load hours, 3.3 percent of load occurs in January from 5-7pm (i.e., hour beginning at 17).

	Month											
	1	2	3	4	5	6	7	8	9	10	11	12
Number of Days:	*15*	*6*	*0*	*0*	*0*	*5*	*13*	*11*	*2*	*0*	*0*	*11*
Hour Beginning												
0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
1	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
2	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
3	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
4	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
8	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.4%	1.1%	0.0%	0.0%	0.0%	0.0%
9	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.4%	1.6%	0.0%	0.0%	0.0%	0.0%
10	0.0%	0.0%	0.0%	0.0%	0.0%	0.9%	2.7%	2.1%	0.0%	0.0%	0.0%	0.0%
11	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.0%	2.2%	0.0%	0.0%	0.0%	0.0%
12	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.2%	0.0%	0.0%	0.0%
13	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
14	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
15	0.0%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.0%
16	0.2%	0.0%	0.0%	0.0%	0.0%	1.1%	3.1%	2.4%	0.4%	0.0%	0.0%	0.4%
17	3.3%	0.4%	0.0%	0.0%	0.0%	0.7%	3.0%	2.4%	0.4%	0.0%	0.0%	2.4%
18	3.3%	1.3%	0.0%	0.0%	0.0%	0.7%	2.7%	2.1%	0.4%	0.0%	0.0%	2.4%
19	2.3%	0.8%	0.0%	0.0%	0.0%	0.7%	2.3%	1.9%	0.4%	0.0%	0.0%	1.7%
20	0.0%	0.0%	0.0%	0.0%	0.0%	0.7%	2.0%	2.1%	0.2%	0.0%	0.0%	0.4%
21	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	2.0%	1.6%	0.0%	0.0%	0.0%	0.0%
22	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%	0.4%	0.0%	0.0%	0.0%	0.0%
23	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

C) Establish Hourly Avoided Distribution Costs by Year

- Distribute the annual $/kW avoided distribution cost from Step 1 across hours in a given year based on the peak load hour determination performed in Step 2.B.
    - Note: If a DG system's output covered all of the peak hours, it would realize 100% of the avoided distribution cost value.

- Complete this process for each year of the study through 2035.

C.7.4 Inputs, Assumptions, and Notes

Inputs

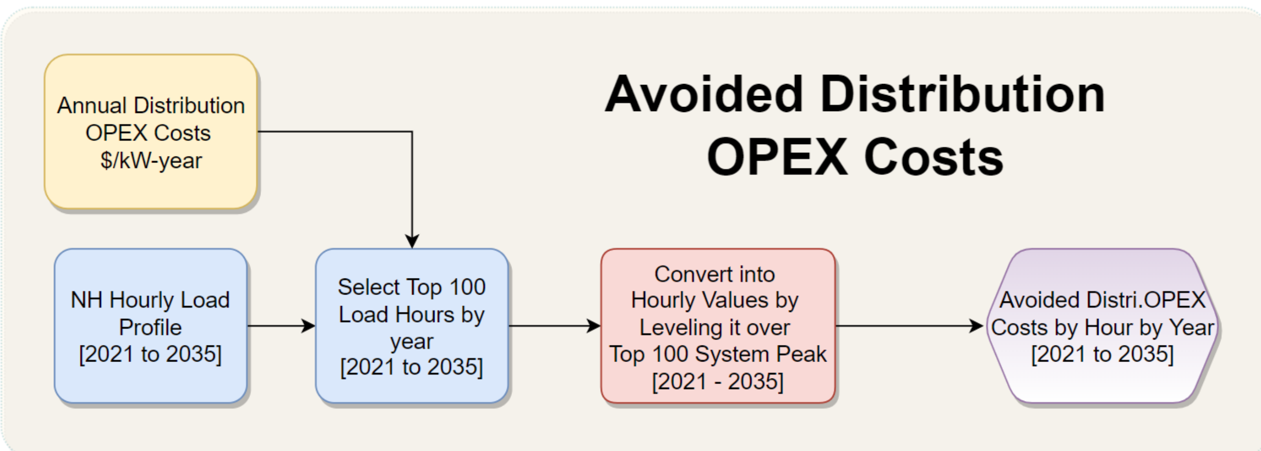
Inputs	Sources
Distribution Capital Expenditure Proxy Value	Utility data and interviews
	LVDG Study
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

C.8 Distribution System Operating Expenses

C.8.1 Rationale

Utilities incur costs to maintain the safe and reliable operation of distribution facilities, which includes maintenance of substations, wires, and poles and repairs and replacements of portions of the distribution system over time. These costs are variable and partially a function of the volume of energy transferred through the system. While this criterion may be a cost and/or avoided cost stream – reflecting an increase or decrease in costs associated with infrastructure and services as a result of DG deployment – for this assessment, we assume that it is a positive avoided cost value and that any costs incurred rather than avoided are achieved under the T&D System Upgrades criterion.

C.8.2 Model Map



C.8.3 Avoided Cost Methodology

Step 1: Annual Distribution OPEX Costs

Ask the utilities to identify distribution system operating expense budget items that could be offset through reduced load. Normalize these costs by expected load increases during the same time period.

Step 2: Distribute Annual Avoided Distribution OPEX Value by Hour

- Assume distribution system operational costs are largely driven by the highest load hours on the system. Rank the top 100 hours in each year (2021-2035) to select the distribution system peak hours.

- Distribute the annual $/kW avoided distribution cost across hours in a given year based on the peak load hour determination performed for the Distribution Capacitycriterion.

C.8.4 Inputs, Assumptions, and Notes

Inputs

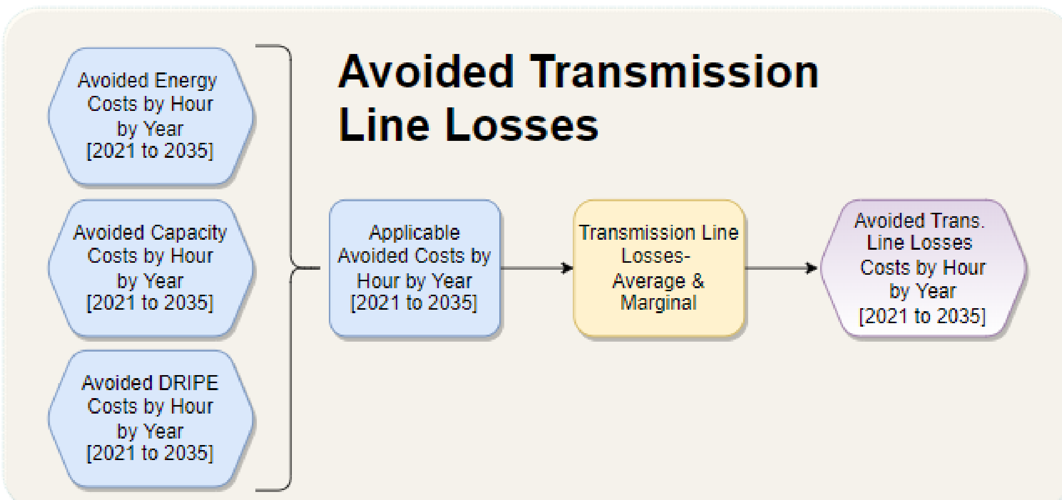
Inputs	Sources
Distribution OPEX Expenditure Proxy Value	Utility data and interviews
	FERC Form 1 Filings
NH System Load Profiles	Utility Data Requests
	AESC 2021 study forecasts

C.9 Transmission Line Losses

C.9.1 Rationale

The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the transmission network. Any surplus energy exported to the system from the DG resources is assumed to be contained within the distribution network, and therefore no transmission backflow occurs due to surplus energy. The avoided transmission line losses apply to the total energy produced by the distributed energy resource. To note, this avoided cost criterion is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. In other words, any inherent value from avoiding transmission line losses attributable to those other criteria has been pulled out (to avoid double-counting) and is included here in this stand-alone transmission line loss criterion.

C.9.2 Model Map



C.9.3 Avoided Cost Methodology

Step 1: Establish an Appropriate Line Loss Factor

- Assess transmission line loss factors from NH electric distribution utilities, AESC 2021, and other relevant valuation studies to determine an appropriate system-wide transmission line loss factor.
- Apply marginal line loss factors to the top 100 NH system peak hours in a year, and average line loss values to the remaining hours.[20]

[20] Line losses vary as a function of grid conditions. During peak loading periods losses can be higher as a result of increased current flows. Average transmission line losses were estimated to be 2.5% while marginal line losses were estimated to be 3.75% (1.5 times the average line loss factors). This assumption was established in a previous study from the Regulatory Assistance Project (RAP) available here.

Step 2: Calculate Historic and Forecasted Hourly Avoided Costs

- Multiply the transmission line loss factor for a given hour by the following avoided cost values for that hour to determine the hourly avoided transmission line loss values:[21]
    - Hourly avoided energy costs (See C.1.)
    - Hourly avoided capacity costs (See C.2.)
    - Hourly avoided DRIPE (See C.11.)

C.9.4 Inputs, Assumptions, and Notes

Inputs:

Inputs	Sources
Transmission Line Losses	AESC 2021 study, NH Utility Data Request (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

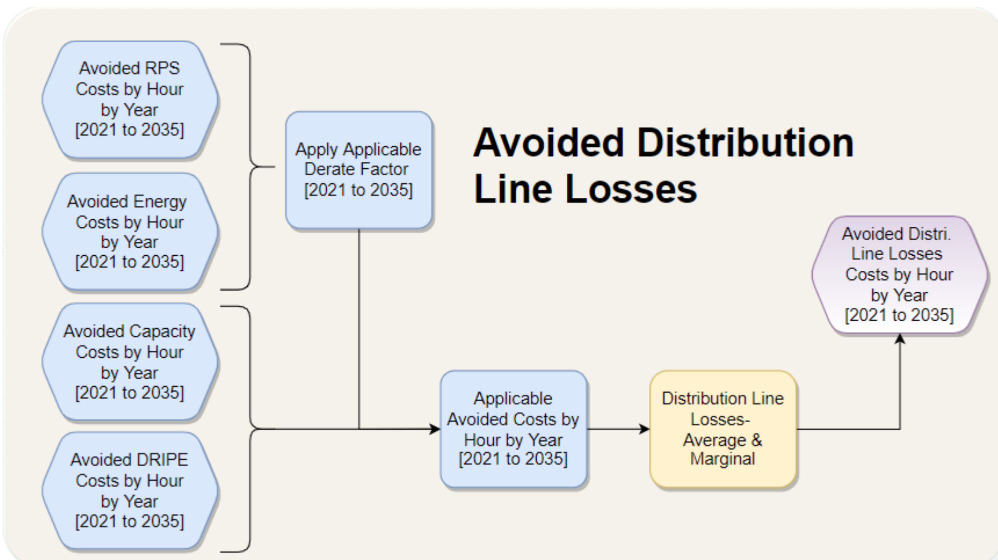
[21] This is consistent with the approach laid out in Table 136 in the AESC.

C.10 Distribution Line Losses

C.10.1 Rationale

The electricity generated by customer-sited DG resources reduces the amount of energy that would otherwise be distributed through the distribution network. Any surplus energy exported back to the grid is assumed to be distributed within the distribution network. Therefore, the avoided distribution line losses apply only to the behind-the-meter or self-consumed portion of the energy produced by the distributed energy resource. To note, this avoided cost criterion is a cumulative value, incorporating line loss value from all relevant avoided cost criteria: energy, capacity, RPS compliance and wholesale market price suppression. In other words, any inherent value from avoiding distribution line losses attributable to those other criteria has been pulled out (to avoid double-counting) and is included here in this stand-alone distribution line loss criterion.

C.10.2 Model Map



C.10.3 Avoided Cost Methodology

Step 1: Establish an Appropriate Line Loss Factor

- Gather sector-specific distribution line loss factors from New Hampshire electric distribution utilities. Apply sector-specific marginal line loss factors to the top 100 NH system peak hours in a year, and sector-specific average line loss factors to the remaining hours.[22]

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[22] Line losses vary as a function of grid conditions. During peak loading periods losses can be higher because of increased current flows. Average distribution line losses were estimated to be 7.5% for the residential sector and between 4.4% and 6.4% commercial sector, while marginal line losses were estimated to be 1.5 times the average line loss factors. This assumption was established in a previous study from the Regulatory Assistance Project (RAP) available here.

Step 2: Apply Distribution Line Losses

- Calculate an appropriate derate factor – which is used to reduce the volume of energy produced such that line loss avoided costs only apply to energy that is consumed behind-the-meter – for each customer class and system archetype.
- Calculate line losses for each customer-generator sector and for each hour by multiplying the line loss factor for a given hour by the following avoided cost values in that hour and the derate factor to determine the hourly avoided distribution line loss values:
  - Hourly avoided energy costs (See C.1.)
  - Hourly avoided capacity costs (See C.2.)
  - Hourly avoided RPS costs (See C.4.)
  - Hourly avoided DRIPE (See C.11.)

C.10.4 Inputs, Assumptions, and Notes

Inputs

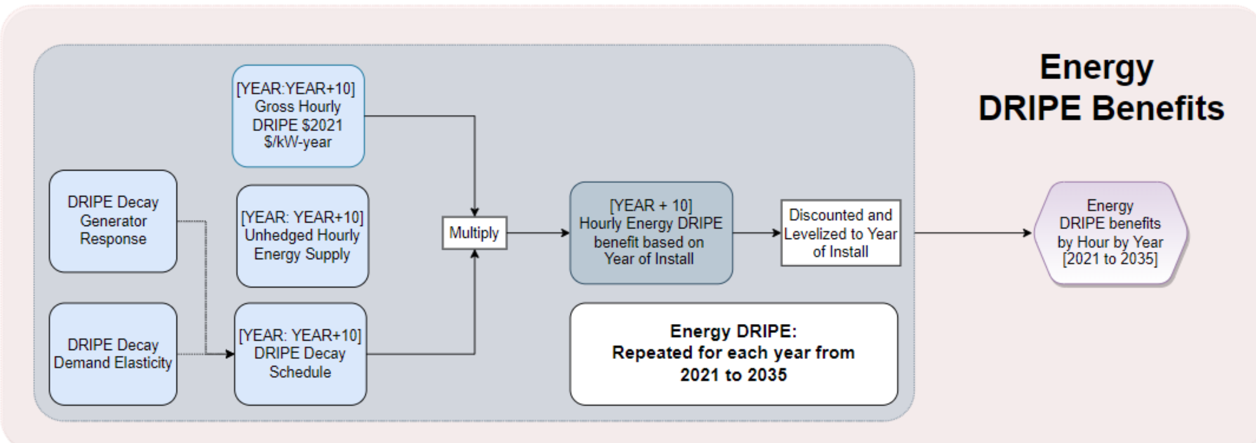
Inputs	Sources
Distribution Line Losses	AESC 2021 study, NH Utility (primary), RAP Study (secondary)
NH System Load Profiles	AESC 2021 study, NH Utilities

C.11 Wholesale Market Price Suppression

C.11.1 Rationale

The electricity produced at the customer-generator's site reduces the overall energy and capacity procured through the wholesale market, resulting in lower market clearing prices. This price suppression effect, also known as Demand Reduction Induced Price Effect, or DRIPE, is ultimately passed on to all market participants. For this analysis, we considered the direct price-suppression benefits that result from reduced energy (Energy DRIPE), reduced Capacity (Capacity DRIPE), and the indirect price-suppression benefits that result from reduced electricity demand on gas prices which in turn reduce electricity prices (Electric-to-Gas-to-Electric Cross-DRIPE).

C.11.2 Model Map – Energy DRIPE



C.11.3 Avoided Cost Methodology– Energy DRIPE

Step 1: Calculate Energy DRIPE for Each Study Year (2021-2035)

a) Calculate Net Energy DRIPE

- Use gross energy DRIPE wholesale values (based on Counterfactual #2 scenario and intrazonal-only values for New Hampshire) from the AESC 2021 study as the starting point for each study year, The values reflect four periods: summer on-peak, summer off-peak, winter on-peak, and winter off-peak.

- Multiply gross energy DRIPE by the percentage of unhedged energy supply in New Hampshire – i.e., the portion of energy purchased on the spot market.

- Multiply the values by the energy DRIPE benefits decay schedule, which varies based on year of DER installation. The benefits decay schedule reflects a lower DRIPE value in future years as a) existing generating resources respond to lower prices by becoming less efficient, and b) customers respond to lower energy prices by increasing demand. To note, based on the methodology in the AESC 2021 study, energy DRIPE value persists for 11 years, including the year of installation.

b) Levelize to Year of Installation

- Discount the series of four net energy DRIPE values for each study year (e.g., for 2021: 2021 to 2031 summer on-peak; 2021 to 2031 summer off-peak; 2021 to 2031 winter on-peak; and 2021-2031 winter off-peak), then calculate the levelized values for the year of installation to develop four net energy DRIPE values for each study year.

Step 2: Convert to Hourly Values

- Convert the four season/peak period values[23] into 8760 hourly values using the following assumptions:
  - The summer on-peak value is applied to the corresponding ISO-NE summer months and on-peak hours. The summer off-peak value is applied to the corresponding ISO-NE summer months and off-peak hours.
  - The winter on-peak value is applied to the corresponding ISO-NE winter months and on-peak hours, while the winter off-peak value is applied to the winter off-peak hours.
- This conversion to hourly values for each year is repeated for all study years (2021-2035).

C.11.4 Inputs, Assumptions, and Notes– Energy DRIPE

Inputs	Sources
Gross Energy DRIPE Forecast	AESC 2021 study*

**See note 2, below.*

Assumptions and Notes

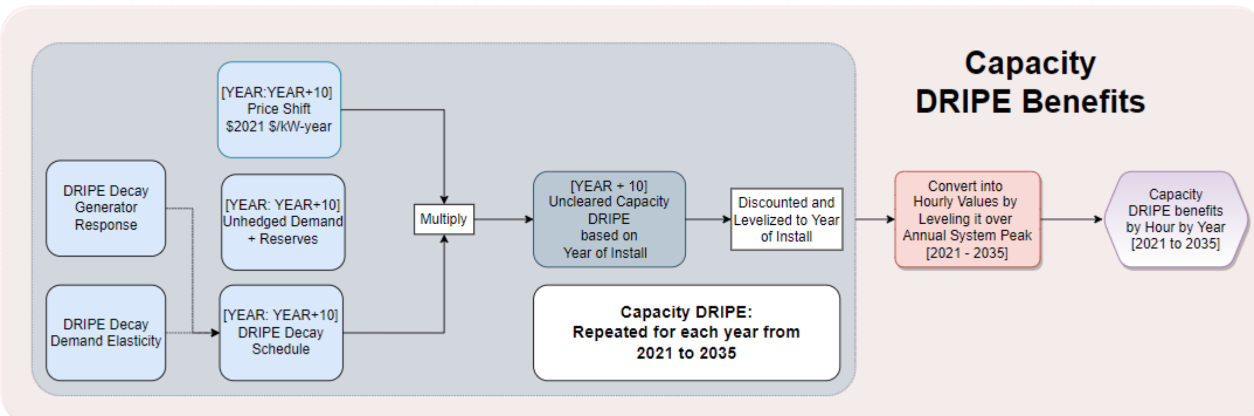
- For systems installed in 2021, the annual energy DRIPE persist through 2031. This is because the AESC assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and reliable, while customers might respond to lower energy prices by using more energy.

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

- The DRIPE values from 2021 to 2025 are available in the AESC 2021 Counterfactual Workbook #2. However, because the AESC study does not include values beyond 2025, those DRIPE values are modelled outside the workbook by applying the appropriate decay schedule (corrected for customer demand elasticity and generation effects) to the unhedged energy portion and gross DRIPE values.

- The intrazonal DRIPE values are proportional to the percentage of the zonal load with respect to the ISO-NE system load. Therefore, zones with less load will have lower zone-on-zone energy DRIPE values than zones with higher load.

C.11.5 Model Map – Capacity DRIPE



C.11.6 Avoided Cost Methodology – Capacity DRIPE

Step 1: Calculate Capacity DRIPE for Each Study Year (2021-2035)

c) Calculate Uncleared Capacity DRIPE

- For each study year, multiply New Hampshire's zonal unhedged demand (from the AESC 2021 Counterfactual #2 workbook), plus a reserve margin, by a benefit decay schedule based on the useful life of the DER and by the applicable annual price shift (which is expressed as $/MW-year per MW).[24] As with energy DRIPE, capacity DRIPE value is assumed to persist for 11 years, including the year of installation.

d) Levelize to Year of Installation

- Generate a series of uncleared capacity DRIPE values for each study year (e.g., for 2021, values are generated for 2021 through 2031), and then discount those values and calculate the levelized values for the year of installation.

[24] The uncleared capacity DRIPE methodology is used as the DG resources are not capacity market participants and therefore their impact on capacity wholesale market prices is linked to changes in unhedged load. Further, unlike other avoided cost components, this is a market impact (benefit) and not a potentially avoided cost that would be allocated through a market.

Step 2: Convert to Hourly Values

- Convert the annual values into 8760 hourly values by distributing the value over a set of peak hours based on an effective load carrying capability (ELCC) approach.[25] Repeat this conversion to annual hourly values for all study years (2021-2035).

C.11.7 Inputs, Assumptions, and Notes – Capacity DRIPE

Inputs

Inputs	Sources
Uncleared Capacity DRIPE Forecast	AESC 2021 study*
Reserve margin	AESC 2021 study

**See note 2, below.*

Assumptions and Notes

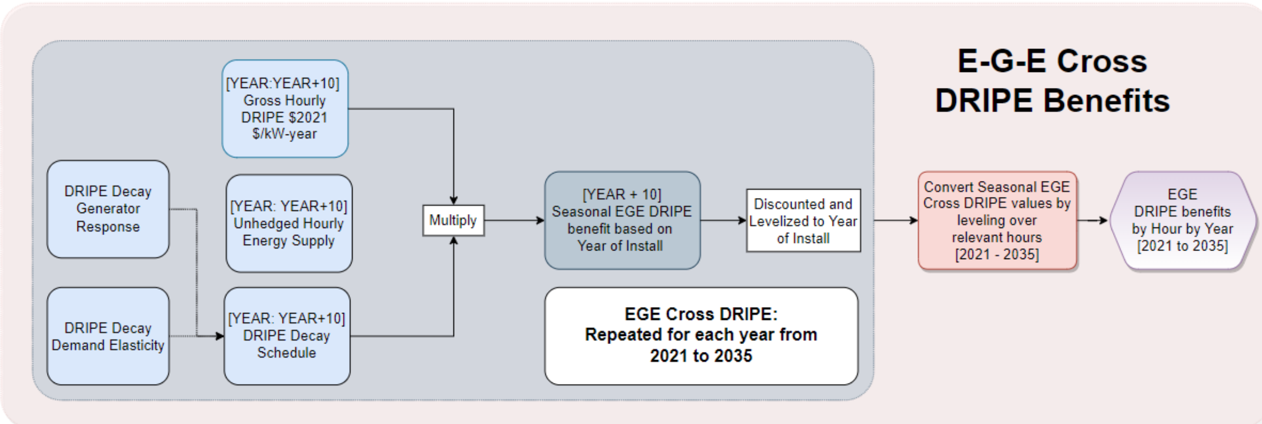
- For systems installed in 2021, the annual capacity DRIPE persist through 2031. This is because the AESC 2021 study assumes that the DRIPE effect decays over time because owners of existing generating resources, in response to lower energy and capacity prices, would allow their assets to become less efficient and reliable, and customers might respond to lower energy prices by using more energy.

- The DRIPE values from 2021 to 2025 are available in the AESC 2021 Counterfactual Workbook #2. However, because the AESC study does not include values beyond 2025, those DRIPE values are modelled outside the workbook by using the appropriate decay schedule (corrected for customer demand elasticity and generation effects).

- The intrazonal DRIPE values are proportional to the percentage of the zonal load with respect to the ISO-NE system load. Therefore, zones with less load will have lower zone-on-zone Capacity DRIPE values than zones with higher load.

[25] ISO-NE has indicated that it will employ an ELCC approach for assessing resource capacity contribution to resource adequacy in the Forward Capacity Market. Because a strict application would require probabilistic modelling, a simplified approach is used here.

C.11.8 Model Map – Electric-to-Gas-to-Electric Cross DRIPE



C.11.9 Avoided Cost Methodology – Electric-to-Gas-to-Electric Cross DRIPE

Step 1: Calculate Electric-Gas-Electric Cross DRIPE for Each Study Year (2021-2035)

e) Calculate Electric-Gas-Electric Cross DRIPE for Summer and Winter

- For each study year, multiply New Hampshire's zonal unhedged energy demand (from the AESC 2021 Counterfactual #2 workbook) by a decay schedule based on the useful life of the DER multiplied by the applicable Electric-Gas-Electric coefficient (which is expressed as $/TWh per MWh/Period Reduced). As with energy DRIPE, Electric-Gas-Electric Cross DRIPE value persists for 11 years, including the year of installation.

f) Levelize to Year of Installation

- Generate Electric-Gas-Electric Cross DRIPE values for each study year (e.g., for 2021, values are generated for 2021 through 2031), and then discount those values and calculate the levelized values for the year of installation.

Step 2: Convert to Hourly Values

- Convert the seasonal $/kWh values (summer/winter) by distributing over the hours corresponding to each season. This conversion to hourly values is repeated for each year of the study period (2021-2035).

C.11.10 Inputs, Assumptions, and Notes – Electric-to-Gas-to-Electric Cross DRIPE

Inputs

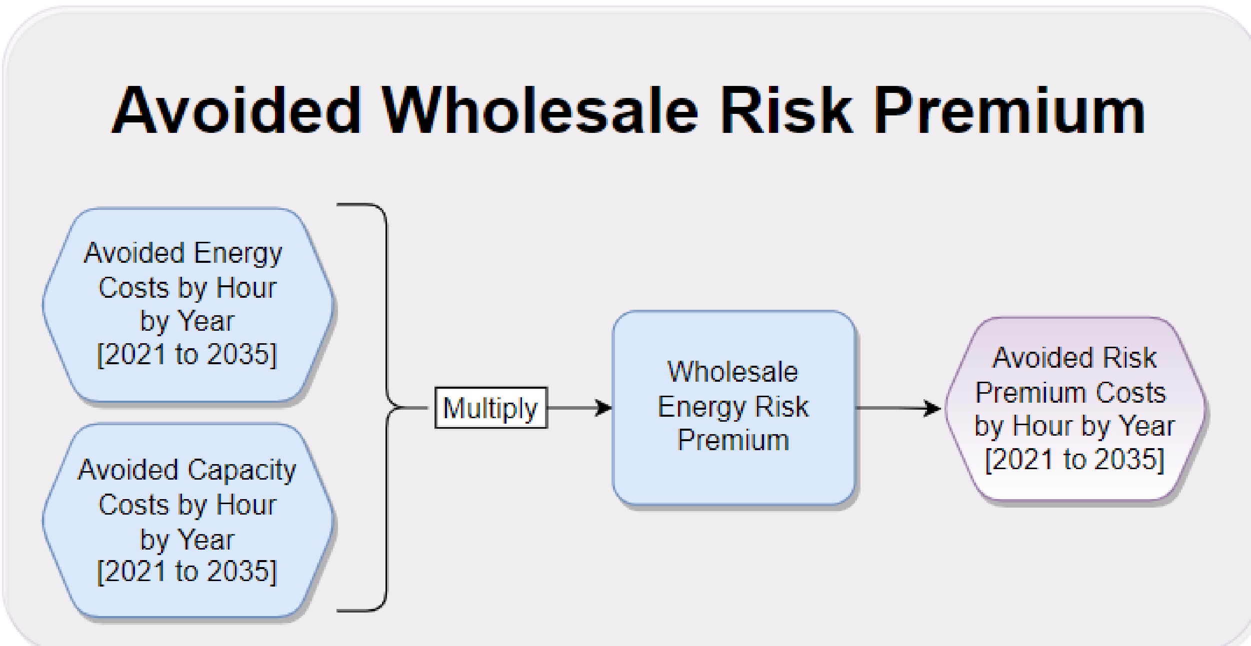
Inputs	Sources
E-G-E DRIPE Coefficients	AESC 2021 study

C.12 Hedging/Wholesale Risk Premium

C.12.1 Rationale

The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary services. In part, this is because the wholesale suppliers of retail customer load requirements incur various market risks when they set contract prices in advance of supply delivery periods. Therefore, every reduction in wholesale energy and capacity obligations may reduce the supplier's cost to mitigate such risks.

C.12.2 Model Map



C.12.3 Avoided Cost Methodology

Step 1: Determine Risk Premium

- Use a literature review of other studies, utility-specific data, and the AESC 2021 study to determine the most appropriate value for this study[26].

Step 1: Apply to Wholesale Energy and Capacity Costs

- Apply the risk premium to wholesale hourly energy prices (historical and forecasted), including T&D line losses.

[26] AESC 2021 applies the same wholesale risk premium of 8% to avoided wholesale energy prices and to avoided wholesale capacity prices,

- Similarly, multiply wholesale hourly capacity prices (historical and forecasted), including T&D line losses, by the wholesale risk premium value.

- Calculate the total wholesale risk premium by summing of the wholesale energy risk premium and the wholesale capacity risk premium.

C.12.4 Inputs, Assumptions, and Notes

Inputs:

Inputs	Sources
Wholesale Risk Premium	AESC 2021 study, utility-specific data, and other sources

Assumptions and Notes

- In keeping with the approach used in the AESC 2021 study, the same wholesale risk premium is applied to avoided wholesale hourly energy prices and avoided wholesale hourly capacity prices.
- Retail suppliers mitigate some risk by hedging their costs in advance, but there is still uncertainty in the final price borne by the supplier. The wholesale risk premium reflects suppliers' costs to mitigate wholesale risks associated with unavailable resources and changes in load. As such, it is applied to retail sales, and thus total wholesale energy and capacity costs must be adjusted upward to account for T&D line losses.

C.13 Distribution Utility Administration Costs

C.13.1 Rationale

An increase in solar installed capacity may affect associated electric distribution utility administration costs, including NEM program administration, metering, billing, collections, unreimbursed interconnection costs, evaluation, and load research.

C.13.2 Avoided Cost Methodology

Step 1: Develop DG-Related Costs to Utilities

- Gather NEM program administration costs associated with metering and billing, collections, unreimbursed interconnection costs, evaluation, load research, etc. from the electric distribution utilities.
- The applicable cost inputs – metering, program administration, interconnection and engineering costs were bundled together as utility administration costs. The administration costs were developed on a per-installation basis and appropriately scaled based on the DG forecasts developed for each utility and segment.
- Levelize these costs over solar forecasts to estimate the program administration costs by year.

C.13.3 Inputs, Assumptions, and Notes

Assumptions:
NEM program credits for customer-generator net exports are not accounted for under this cost component, which covers costs specific to NEM program implementation and administration and are not directly attributable to DG deployment levels.

C.14 Transmission and Distribution System Upgrades

C.14.1 Rationale

In the context of this study, the Transmission and Distribution System Upgrades component is an incurred cost item. It encompasses all costs related to transmission and distribution system upgrades that are driven by the addition of net-metered DG to the grid, with the exception of those covered by DG customer payments or reimbursements. However, it is challenging within the scope of this study to isolate those transmission and distribution system upgrade costs that are attributable to DG installations or any investments funded by DG customers that result in avoided costs or benefits to other ratepayers. As such, a qualitative review was completed for this criterion and the findings are included in the main body of the report.

C.15 Environmental Externalities

C.15.1 Rationale

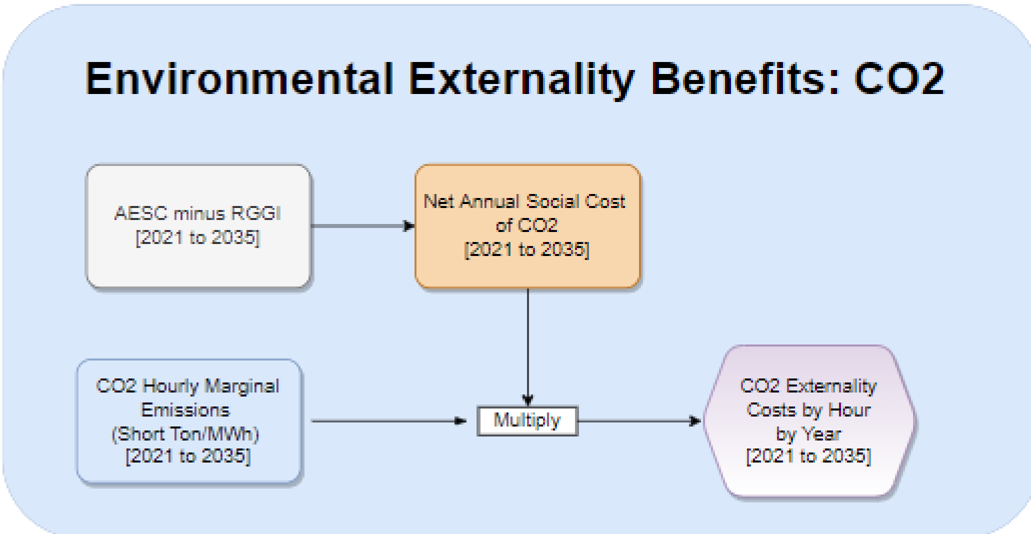
The electricity generated from a DG resource may reduce marginal emissions from fossil fuel plants. A portion of the avoided costs of such reduced emissions are already included as environmental program compliance costs embedded in wholesale energy prices. This study sensitivity focuses on evaluating the remaining non-embedded environmental externalities avoided costs resulting from DG resource electricity production.

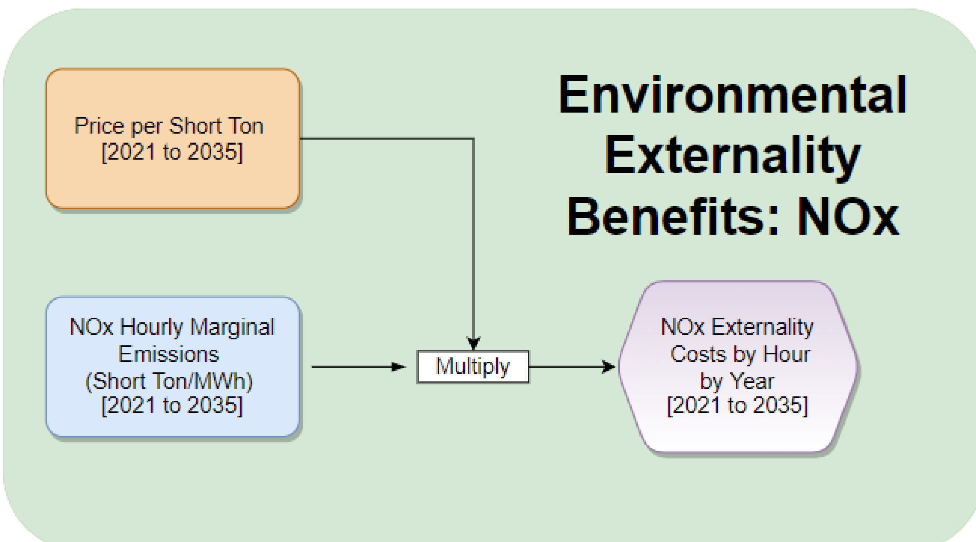
SO_2 emissions: The AESC 2021 study assumes that all coal-fired generation, the primary source of SO_2 emissions from electricity generation, is taken offline by 2025. For this analysis, the value of SO_2 emissions is assumed to be minimal and therefore it is not included in the environmental externalities value.

Particulate matter: The AESC wholesale energy price forecasts do not include any costs associated with particulate matter. When considering energy generation, particulate matter is primarily produced by coal and biomass combustion. Because coal-fired generation is assumed to be taken offline by 2025, the impacts of particulate matter from coal combustion are not included in the environmental externalities value. Although biomass remains a generation source throughout the study period, it provides baseload power rather than marginal generation. Because biomass facilities do not generate electricity on the margin, reductions in biomass-related particulate matter emissions are not expected as a result of net-metered DER load reductions. The impacts of particulate matter are therefore also excluded from the environmental externalities value.

Methane: Although the societal costs of methane are considerable on a per ton basis, methane emissions are challenging to quantify and forecast as they primarily occur upstream from power generation during the production, processing, storage, transmission, and distribution of natural gas and oil, and have not been thoroughly monitored or studied. In addition, the U.S. government is taking steps to substantially reduce upstream methane emissions through a proposed rule applicable to new and existing facilities, which targets a 74% reduction in methane emissions from oil and gas production from 2005 levels by 2030. Given the challenges inherent in developing methane emissions forecasts for ISO-NE, and in view of federal government proposals to reduce methane emissions during the study period, methane is not included in the environmental externalities value.

C.15.2 Model Map





C.15.3 Avoided Cost Methodology

Step 1: Calculate Environmental Externality Benefit of CO_2 (2021-2035)

- Select the social cost of carbon forecast from the AESC 2021 study (October 12, 2021)[27] (based on the 2% discount rate) as the gross Social Cost of Carbon (SCC, $/short ton).[28]

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[27] Of the two approaches to estimate the cost of carbon, the marginal abatement cost test is challenging from a regional perspective, given that several variables such as technology price, technical potential and policies change over a period of time.

[28] This AESC SCC scenario is based on the New York State SCC – which was developed while the federal SCC was suspended. We believe this is an appropriate scenario for the VDER study, in view of the regional proximity to and similarities between New York

- Calculate the net SCC for each year by calculating the difference between the forecasted gross SCC and forecasted RGGI allowance prices. As RGGI allowance prices are already embedded in wholesale energy market prices, these are subtracted from the gross SCC values to establish a net SCC over the study period.
- Multiply the net SCC by the corresponding AESC 8760 hourly marginal emission rates (short ton per MWh) (2021 to 2035), as outlined in the AESC 2021 study workbooks, to determine the environmental externality avoided cost for CO_2.

Step 2: Calculate Environmental Externality Benefit of NO_x (2021-2035)

- Note that the AESC 2021 study assumes no embedded NO_x prices, because the New England states are exempt from the CSAPR program and state specific regulations in Massachusetts and Connecticut are unlikely to be binding. Therefore, the externality benefit of NO_x is equal to the AESC price per short ton of NO_x with no further adjustment. The value of the externality benefit of NO_x for this study was $14,700 per short ton throughout the study period.
- Multiply the price per short ton of NO_x in AESC 2021 by the corresponding AESC 8760 hourly marginal emission rates (2021 to 2035), as outlined in the AESC study workbooks, to determine the environmental externality benefit for NO_x.

C.15.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
CO_2 Marginal Emissions Rates	AESC 2021 study
Societal Cost of Carbon (2% discount rate scenario)	AESC 2021 study (October 2021 update), NYS SCC
RGGI Allowance Price Forecast	AESC 2021 study
NO_x Marginal Emissions Rates	AESC 2021 study
Short Ton Price of NO_x	AESC 2021 study

and the New England states in terms of energy landscape and policy context. Moreover, the NYS SCC Guideline values consider the global impact of emissions, use reasonable discount rates, and consider high impact events through low discount rates. The net SCC (after removing RGGI) ranged from $111 per short ton to $128 per short ton from 2021 to 2035.

Assumptions:

- The environmental externalities benefit associated with avoided Transmission and Distribution Line Losses have been included in the environmental externalities avoided cost component because this avoided cost component is treated as a sensitivity in the study.

C.16 Distribution Grid Support Services

C.16.1 Rationale

Generally speaking, this component may be an incurred cost or an avoided cost, reflecting an increase or decrease in costs associated with distribution system support services required as DG resource penetration increases. For the purpose of this study, this criterion is assumed to represent an avoided cost stream, with any incurred costs included under the T&D System Upgrades component. This criterion was evaluated using a qualitative review.

C.17 Resilience Services

C.17.1 Rationale

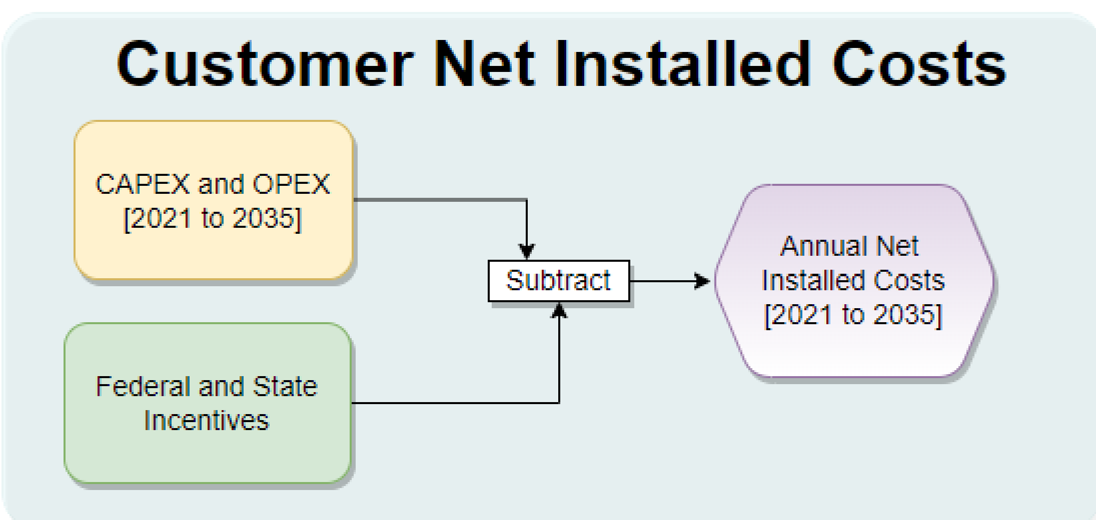
In this study, resilience services are defined as the ability of DERs to provide back-up power to a site in the event that it loses utility electricity service.[29] Resiliency has the potential to provide significant value, although this value is expected to be highly context-specific. This criterion was assessed using a qualitative review.

C.18 Customer Installed Costs

C.18.1 Rationale

This component was not considered as part of the avoided cost value stack, but may be used to evaluate how NEM crediting and compensation may affect reasonable opportunities to invest in DG and receive fair compensation, as contemplated by House Bill 1116 (2016).

C.18.2 Model Map



[29] This definition was sourced from the U.S. DOE Office of Energy Efficiency and Renewable Energy, available online: https://www.energy.gov/eere/femp/distributed-energy-resources-resilience.

C.18.3 Methodology

Step 1: Develop DG Customer's CAPEX and OPEX Projections

- Develop projections of upfront capital costs (CAPEX) and annual operational costs (OPEX[30]) over the lifetime of the DG system, using NREL's Annual Technology Baseline[31].

Step 2: Determine Applicable Federal and State Incentives

- Develop annual incentive projections for solar PV systems based on federal investment tax credits and New Hampshire renewable energy rebates for residential and commercial projects.
- Federal ITC assumed to be applied for residential PV systems (26% until 2022, 22%% in 2023 and 0% after) and commercial and utility-scale PV systems (26% until 2022, 22%% in 2023 and 10% after). ITC assumed to be applied to solar + storage systems as well.

Step 3: Customer Installed Costs

- Calculate customer installed costs over the study period by summing the net present value of the CAPEX and OPEX costs, minus available incentives.
- The costs are expressed as a net $/kW cost as well as a levelized cost per kWh over system production for each system type – residential and commercial solar (south facing and west facing), residential and commercial solar and energy storage and small hydro.

C.18.4 Inputs, Assumptions, and Notes

Inputs

Inputs	Sources
Solar CAPEX and OPEX Costs	NREL's Annual Technology Baseline (ATB)
Solar System Sizes: Residential, Commercial and LGHC[32]	NH Utility Data

[30] Opex costs include admin feed, labor, insurance, land lease payments, operating labour, property taxes, sit security, project management, general (scheduled and unscheduled) maintenance, the annualized present value of large component replacement (inverters) Commercial PV | Electricity | 2021 | ATB | NREL
[31] Data | Electricity | 2021 | ATB | NREL, Capex and opex costs for solar PV (residential, commercial), energy storage costs (residential, commercial) and small hydro were based on the NREL's Annual Technology Baseline
[32] System sizes are align with the system assumptions used throughout the study period.

D. High Load Growth Scenarios Methodology

The value of distributed energy resources will vary to some degree according to projected load growth in New Hampshire. In part, future electricity load forecasts will depend on the deployment of building electrification and transportation electrification technologies. Uncertainty around the future deployment of those technologies, however, translates into uncertainty regarding projected load growth in the state. The High Load Growth Scenarios (HLGS) sensitivity analysis considers several scenarios for increased load growth to investigate the impact of such future load increases on avoided cost value stack criteria.

The following steps outline the approach used to complete the HLGS analysis through the development of three scenarios that estimate a) the incremental impact of electrification on system load, and b) the incremental impact of that electrification on avoided cost criteria in the value stack.

D.1 Estimating Incremental Impact on System Load

The base value stack avoided costs are based in large part on the Avoided Energy Supply Costs in New England (AESC) 2021 study, counterfactual #2 scenario. The HLGS loads are therefore compared to the loads under AESC counterfactual #2 to assess incremental impacts. Building electrification and transportation electrification are varied under multiple scenarios under the HLGS sensitivity analysis, as described below.

The HLGS analysis included three scenarios:

1. Scenario 1: Impact of AESC building electrification (BE)[33]
2. Scenario 2: Impact of AESC building electrification and high transportation electrification[34]
3. Scenario 3: Impact of high building electrification[35] and high transportation electrification

[33] The AESC counterfactual #2 did not include the programmatic resource impacts of building electrification measures, but these impacts were included in counterfactuals #3 and #4. The building electrification measure impact included in counterfactuals #3 and #4 was added to counterfactual #2 to derive Scenario 1.

[34] The AESC included transportation electrification impacts across all four counterfactual scenarios, so some degree of transportation electrification was considered in the base avoided cost values taken from the AESC counterfactual #2 scenario. For HLGS scenarios 2 and 3, transportation electrification was assumed to exceed the AESC assumptions such that light-duty vehicle uptake aligned with a market share target of 26% by 2026, 90% by 2030, and 100% by 2035. Data availability on medium- and heavy-duty vehicle stocks and sales in New Hampshire was limited, so market share targets could not be established. Deployment was instead accelerated over AESC assumptions to align with the modified uptake trends in the light-duty sector, resulting in load impacts that exceeded AESC values by up to 58% at the mid-point of the study, but were approximately aligned with AESC assumptions by 2035.

[35] The high building electrification assumptions included an accelerated timeline for heat pump installations in residential buildings, exceeding AESC assumptions by up to 30% at the study mid-point, and 14% by the study end point.

Scenario	BE	TE
Scenario 1: Impact of BE	AESC	AESC
Scenario 2: Impact of BE and high TE	AESC	High
Scenario 3: Impact of high BE and high TE	High	High

Each scenario's hourly demand curve was compared to the hourly demand curve under the AESC 2021 study counterfactual #2 to estimate incremental load impacts.

D.2 Estimating Incremental Impacts on Avoided Costs

Although load growth may impact the total costs ($) associated with many of the value stack criteria, the focus of this analysis is to understand impacts to the avoided cost per unit energy or unit demand ($/kWh or $/kW). Avoided cost per unit energy or per unit demand impacts may arise for those avoided cost criteria that are impacted by wholesale market adjustments resulting from changes in load. Those adjustments are similar to DRIPE, and in fact the elasticity factors used to calculate impacts (described below) are a precursor to DRIPE.

To calculate the HLGS impacts on avoided costs, the change in hourly demand (or the incremental load impacts) associated with each HLGS scenario are compared to the base case, AESC counterfactual #2. Next, the change in demand is multiplied by the hourly elasticity factor to calculate the percentage change in avoided cost, as shown in the following equation:[36]

$$\%\ change\ in\ avoided\ cost = elasticity\ \times \%\ change\ in\ demand$$

The percent change in avoided cost (avoided cost impact) is calculated for the volumetric (kWh) and demand (kW) criteria. Volumetric avoided cost impacts are calculated using the change in hourly demand between the scenarios and the base case, while capacity avoided cost changes are calculated using the change in annual peak demand.

Volumetric avoided cost impacts are applied to the following avoided cost criteria (that depend on wholesale energy prices):

- Energy
- Ancillary services and load obligation charges
- Risk premium/hedging
- DRIPE Energy
- RPS compliance

[36] Price elasticity factors (and the equation used for this analysis) were calculated in the AESC 2021 study using the relationships between prices ($/MWh or $/kW-year, for energy and capacity respectively) and demand (MW).

Capacity avoided cost impacts are applied to the following cost criteria (that depend on wholesale capacity costs):

- Capacity costs
- DRIPE Capacity

A number of avoided cost criteria are expected to remain unchanged. **That is not to say that the total costs ($) will not change with increases in load, but rather that the costs per unit energy or per unit demand cost criteria are not expected to change.** These cost criteria are:

- Transmission capacity
- Distribution capacity
- Transmission charges
- Transmission and distribution line losses
- Utility administrative costs
- T&D system upgrades
- Distribution OPEX

Increases in marginal demand would also increase the high emitting resources on the margin, which could increase the emissions rates for CO_2 and NO_x under the different HLGS scenarios. Therefore, the impact on environmental externalities is modeled by conducting a regression analysis that compares the demand with the AESC marginal emissions rates to estimate the emissions levels under the three HLGS scenarios.

E. Market Resource Value Scenario Methodology

The market resource value scenario (MRVS) sensitivity analysis estimates the value of aggregated DER resources participating directly in relevant wholesale power markets for those criteria where there is a readily discernible market value or a value that is different than those established in the load reduction value estimates. Specifically, the MRVS analysis considered the ability of DERs to realize value in the wholesale power markets through provision of **energy**, **capacity**, and **ancillary services**. The methodology used for each value category is described below.

E.1 Energy Value

The market value of energy produced by aggregated DER resources is reflected by zonal LMPs for ISO-NE's New Hampshire load zone. The study team relied on the AESC 2021 wholesale energy forecasts for these values. The values were further adjusted to reflect expected near-term increases in the value of energy. Specifically, hourly price profiles were adjusted for recent increases in natural gas prices and resulting LMPs over the 2021-2025 period. Under the MRVS, the value of energy is considered to be the same as in the base avoided cost value stack.

E.2 Capacity Value

The value of capacity generated by aggregated DER resources assumes participation in ISO-NE's Forward Capacity Market (FCM). The study team relied on the AESC 2021 FCM forecast for these values. The FCM values were converted to hourly values (in $/kWh) using summer and winter reliability hours for establishing Qualified Capacity,[37] which is the basis for capacity credit for which FCM payments are made to generation resources.

E.3 Ancillary Services Value

The value of ancillary services is based on the ability of aggregated DER resources to provide reserves and regulation under ISO-NE's FERC Order 2222 compliance filing as dispatchable DER aggregations. Provision of such services typically requires that resources do *not* participate in the energy market, however, so DER provision of those services is expected to be uneconomic.[38] As such, we did not conduct a detailed quantitative analysis of ancillary services value but included qualitative insights instead.

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[37] Qualified Capacity refers to the capacity that a resource is capable of providing in the summer or winter during specific capacity commitment periods. This is calculated by taking the average median production during the summer reliability hours ending 14:00-18:00 (June to September) and winter hours ending 18:00-19:00 (October to May).

[38] For example, for a solar resource to provide operating reserves, it requires "headroom," which would allow it to increase output in response to a generator activation instruction from ISO-NE. To provide this headroom the generator would need to be dispatched down, resulting in an energy market opportunity cost for the operator.

F. Rate and Bill Impacts Assessment

The Rate and Bill Impacts Assessment is a supplementary study to the Avoided Cost Value Stack Analysis. The assessment provides high-level analysis of the impacts of future DG deployment in New Hampshire on ratepayers, considering both the benefits and the costs that would be incurred by the utilities and load-serving entities. The overall goal of the assessment is to serve as a future-looking estimate of the direction and magnitude of the impacts of future DG deployment on all ratepayers and any potential cost-shifting between customers with and without DG. The Rate and Bill Impacts Assessment is not intended to be a projection of future electricity rates and cost recovery, but it serves as a future-looking approximation of the impacts of projected future DG adoption on retail electricity rates for and bills issued to New Hampshire electric customers.

F.1 Modelling Approach

F.1.1 Rationale

Customers that install distributed generation resources can offset a part of their electric load and thus reduce their electric bills. Some portion of the electricity generated is self-consumed while the remaining portion is generally exported back to the utility distribution system. The electricity generated from distributed resources creates both an upward pressure on rates (due to lost utility revenues and program cost recovery) as well as a downward pressure on rates attributable to avoided utility costs.

F.1.2 Modelling Considerations

The following considerations were made while conducting the Rate and Bill Impacts Assessment:

Electric Retail Rates: Impacts on retail electric rates resulting from the future deployment of behind-the-meter distributed solar PV systems in New Hampshire are evaluated.

Three Electric Utilities: Impacts are assessed for the three electric utilities regulated by the New Hampshire PUC: Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a/ Liberty (Liberty), and Unitil Energy Systems, Inc. (Unitil).

Three Customer Classes: Residential, small general service, and large general service customer classes are modeled as a representation of customers impacted by the adoption of behind-the-meter distributed solar PV systems.

Two Scenarios: The analysis is conducted under two scenarios for DG compensation to illustrate the impacts of different potential DG program designs on ratepayers:

- Net Energy Metering (NEM) Tariff Scenario: This scenario reflects the current net-metering program, based on the alternative net metering tariff adopted by the PUC in 2017. The net export credit rate is based on the alternative net metering tariff, where monthly net exports from systems up to 100 kW capacity are compensated at 25% of the underlying distribution rate component and 100% of the underlying generation and transmission rate components, while hourly net exports from eligible systems larger than 100 kW are compensated at 100% of the underlying generation rate component.
- Avoided Cost Value (ACV) Tariff Scenario: An alternative net export compensation tariff approach based on the outcomes of the VDER Study value stack analysis, where customers are compensated for net exports to the grid based on the avoided cost values determined through the study.

Three Customer Archetypes: The assessment evaluated the rate and bill impacts for three customer archetypes:

- Typical DG Customer: Represents a typical utility customer who adopts a behind-the-meter solar PV system for each customer class.
- Typical Non-DG Customer: Represents a typical utility customer in each customer class who does not deploy a solar PV system.
- Average Utility Customer: Represents the average impacts on a utility customer, without regard to whether the customer has or does not have DG. The rate and bill impacts are computed at the rate class level where the total consumption is divided by the number of customers across each rate class and utility.

Decoupling: Utilities in the state have implemented – or plan to implement - a revenue decoupling mechanism. For simplicity, the study analysis assumes annual reconciliation (i.e., annual rate cases) and assumes that utilities will recover all costs associated with non-avoidable fixed costs. In reality, utilities may have less frequent rate cases. This simplifying assumption avoids the complexity of analysis while still meeting the objectives of the study.

F.1.3 Modelling Framework

Rate Impact Assessment

The equation below highlights the theoretical model used to assess the rate impacts of future DG deployment. The rates post-DG are impacted by the fixed costs and program costs, which are recovered over the load post-DG. When a customer-sited distributed energy resource generates electricity, the utility experiences an immediate reduction in energy consumption, thus leading to a certain amount of lost revenues. However, that generation also generates avoided cost values for the utility and load-serving entities. The "net" of these two components (i.e., the difference between lost revenues and avoided costs) is estimated to represent non-avoidable fixed costs that the utilities would need to recover from ratepayers. Additionally, the analytical framework is intended to account for rate impacts associated with the recovery of program costs and net export bill credits over fewer energy sales.

To summarize, future DG deployment is assumed to have several distinct impacts on rates:

A. Lost revenues to utilities as a result of reductions in electricity consumption.
B. Avoided costs, as indicated and quantified by the Avoided Cost Value Stack assessment.
C. Program and/or system costs incurred by utilities to accommodate DG installation and operation, which include program administration costs and the bill credits provided for net exports.
D. System costs that are recovered over lower energy sales due to the load reductions.

The "net" of these components (i.e., the difference between lost revenues and avoided costs) is estimated to represent proxy of the required fixed cost recovery

A Utilities' revenues are reduced

B Utilities capture benefits from avoided costs

$$Rates_{Post\ DG} = Rates_{Pre\ DG} + \frac{\overbrace{(Lost\ Revenues\ - Avoided\ Costs)}^{Fixed\ Cost\ Recovery} + \overbrace{(Admin\ Costs + Export\ Bill\ Credits)}^{Program\ Costs\ Recovery}}{Load\ _{Post-\ DG}}$$

C Utilities need recover costs to accommodate DG / operate programs

D Costs are recovered over fewer kWh

The above framework is applied for the generation, transmission, and distribution components of rates, considering only appropriate determinants under each. For example, the program cost recovery is applied only to the distribution component of rates. In calculating the rate impacts for each customer class, avoided costs, lost revenues, and program costs are calculated across all customer classes and then redistributed back to individual customer classes based on the principle of 100% cost causation.

Additionally, the framework considers the rate components (e.g., volumetric $/kWh and demand charge $/kW) applicable to each customer class.

Bill Impacts Assessment

As a final step, pre- and post-DG bills are estimated for a typical DG customer, a typical non-DG customer, and the average utility customer in each customer class and by each utility. For each customer class, estimated consumption is multiplied by pre- and post-DG rates to assess the incremental impacts on customer bills attributable to future DG deployment.

F.2 Methodology

F.2.1 Step 1: Develop Baseline (No-DG) and DG scenarios

To assess the impacts of future DG deployment, a non-DG scenario must be developed to serve as a baseline. The non-DG scenario is a hypothetical illustration of the system in the absence of projected new DG capacity and is used to evaluate the impacts attributable to future incremental DG deployment. To develop the DG and non-DG scenarios, the following metrics are estimated for each utility and year of the study period:

- **Load (energy and demand) by utility and rate class with and without DG :** this is calculated by:

  a) Removing the impacts of any annual DG projections included in utilities' current load forecasts (Load Pre-DG), and

$$\mathrm{Load}_{Pre-DG} = \mathrm{Load} - \text{adjustments to remove cumulative "new" DG projections}$$

  b) Adding the DG projections used in the VDER Study (Load post-DG).

$$\mathrm{Load}_{Post-DG} = \mathrm{Load}_{Pre-DG} - \text{Total DG Production Forecasts}$$

- **Annual production by average DG customer in each rate class**[39]**:** Estimated by dividing total forecasted DG production in a given year by the forecasted number of DG customers.

$$Average\ DG\ Production\ per\ DG\ customer = \frac{\text{Total Forecasted DG Production (GWh)}}{\text{Total Number of Forecasted DG Customers}}$$

[39] Behind-the-meter solar PV is assumed to be the dominant distributed generation resource for this assessment.

Additionally, assumptions are made to estimate the portion of DG production consumed behind-the-meter versus that exported to the grid (see key assumptions and sources section below). Grid exports are estimated based on an assessment of system sizing practices, DG generation, and customer load patterns.

- **Electricity consumption and demand[40] for DG, non-DG, and average utility customer in each customer class:**

  To simplify the analysis, all customers in a given customer class, regardless of DG deployment, are assumed to have the same average annual electricity consumption pre-DG, as calculated by the following equation:

$$\text{Avg Consumption}_{Pre-DG} = \frac{\text{Total Consumption}_{Pre-DG}}{\text{Total Customers}_{Pre-DG}}$$

  Consumption post-DG will be calculated as follows for different customer archetypes:

Typical DG Customer	$\text{Consumption}_{DG\ Customer} = \text{Avg Consumption}_{Pre\ DG} - \text{Avg DG Production}$
Typical non-DG Customer	$\text{Consumption}_{Non-DG\ Customer} = \text{Avg Consumption}_{Pre-DG}$
Average Utility Customer	$\text{Consumption}_{Avg\ Customer} = \frac{\text{Total Consumption}_{Post\ DG}}{\text{Total Customers}_{Post\ DG}}$

F.2.2 Step 2: Assess Rate Impacts

First, we calculate the lost revenues associated with each customer class for each utility. The lost revenue is the anticipated revenue lost due to reduced electricity sales:

$$Lost\ Revenue\ = DG\ Production\ x\ Rate_{Pre-DG}$$

[40] A coincidence factor for each customer class will be applied to the system peak demand to estimate customer billed demand (e.g., monthly peak load).

Next, we calculate the avoided costs associated with DG production. The avoided cost value is informed by the value stack assessment by each component (generation, transmission, and distribution). Environmental externalities are not included in any of the avoided cost streams.

$$Avoided\ Costs\ = DG\ Production\ x\ Avoided\ Costs_{Generation,\ Distribution,\ Transmission}$$

The net difference between the lost revenue and the avoided costs serves as a proxy for the fixed cost recovery. For each of the rate components, the following avoided costs are considered:

- Generation: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components[41], while avoided capacity and DRIPE benefits are considered to have an impact on rates.
- Distribution: The avoided distribution costs include avoided distribution CAPEX and OPEX, distribution grid services, T&D system upgrades, and resiliency services.
- Transmission: Transmission capacity and transmission charges are considered under the rate and bill impacts assessment; the rate impacts assessment assumes only the portion attributable to the New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%.

To calculate the program cost recovery, we use both the administration costs and the net export bill credits. The administration costs are the costs incurred by the utilities to administer DG programs and include metering costs, costs for full time engineers to conduct site inspections, and other administrative costs.

The export bill credits represent the compensation provided for DG net electricity exports. Under the NEM Tariff scenario, the export credit rate is based on the alternative net metering tariff, where monthly net exports from systems up to 100 kW capacity are compensated at 25% of the underlying distribution rate component and 100% of the underlying generation and transmission rate components, while hourly net exports from eligible systems larger than 100 kW are compensated at 100% of the underlying generation rate component. The compensation is the net export credits netted by the applicable avoided costs. Under the Alternative ACV Tariff scenario, the net export credits are compensated at the avoided costs determined through the value stack analysis. The compensation under this scenario is the export credit compensation netted by the applicable avoided costs, which in this case is zero.

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[41] Certain cost components such as energy, ancillary services, line losses and risk premium are passed on directly from the market to the end customer through the utility. When a customer generates electricity behind the meter – the avoided energy, ancillary services, line losses and risk premium costs will affect the customer bill but won't change the utility's revenue requirement. DRIPE will affect the clearing price for wholesale energy, thereby affecting the generation rate. In line with other similar studies on rate and bill impact assessment in New Hampshire, avoided capacity costs are considered to impact rates.

$$Export\ Bill\ Credit = [(Export\ Rate - Avoided\ Cost\ Rate) x\ \%\ of\ \ Production\ Exported]$$

The fixed cost recovery and program cost recovery portion of the relevant revenue requirement calculation is distributed over the net system load (post-DG) and its impact is recorded against the pre-DG rate for each year of the study. Thus, the rate impacts are presented as the average annual percentage increase or decrease in rates relative to the non-DG scenario over the period 2021 to 2035 for each customer class to indicate the long-term impact of future DG deployment.

F.2.3 Step 3: Assess Bill Impacts

The pre- and post-DG customer bills are calculated for each customer archetype. As an example, the bill impacts from non-DG customers are shown as follows:

$$\text{PreDG Bills}_{\ Non-DG\ Customer} = \text{Consumption}_{Non-DG\ Customer}\ \text{x Rates}_{\ Pre-DG}$$

$$\text{PostDG Bills}_{\ Non-DG\ Customer} = \text{Consumption}_{Non-DG\ Customer}\ \text{x Rates}_{\ Post-DG}$$

$$\text{Bill Impact}_{\ Non-DG\ Customer} = \frac{Post\ DG\ Bills_{Non-DG\ Customer}}{\text{PreDG Bills}_{\ Non-DG\ Customer}} - 1$$

Although the bill impacts are calculated for each year during the study period, the bill impacts are presented as the average annual percentage increase or decrease in customers’ bills attributable to future DG deployment over the period 2021 to 2035 for each of the typical customer archetypes, in each case considered to estimate bill reductions and potential cost-shifting between DG customers and non-DG customers and by the average customer.

F.3 Key Assumptions and Sources

F.3.1 Customer Class Assumptions

The retail electric customers for each utility are segregated into three broad classes: Residential, Small General Service, and Large General Service. The customer count for each rate class across the three utilities were informed by data provided by the utilities. The classification of commercial customers was based on the average annual electric sales. Small general service customers were assumed to have electric sales less than 1 million kWh, while all customers with electric sales greater than 1 million kWh were classified as large general service.

The rate and bill impacts assessment analyzes the impacts of avoided costs on generation, distribution, and transmission rate components. Environmental Externalities are not included in the rate and bill impacts assessment. For each of the three rate components, the following assumptions were made for the rate and bill impacts assessment:

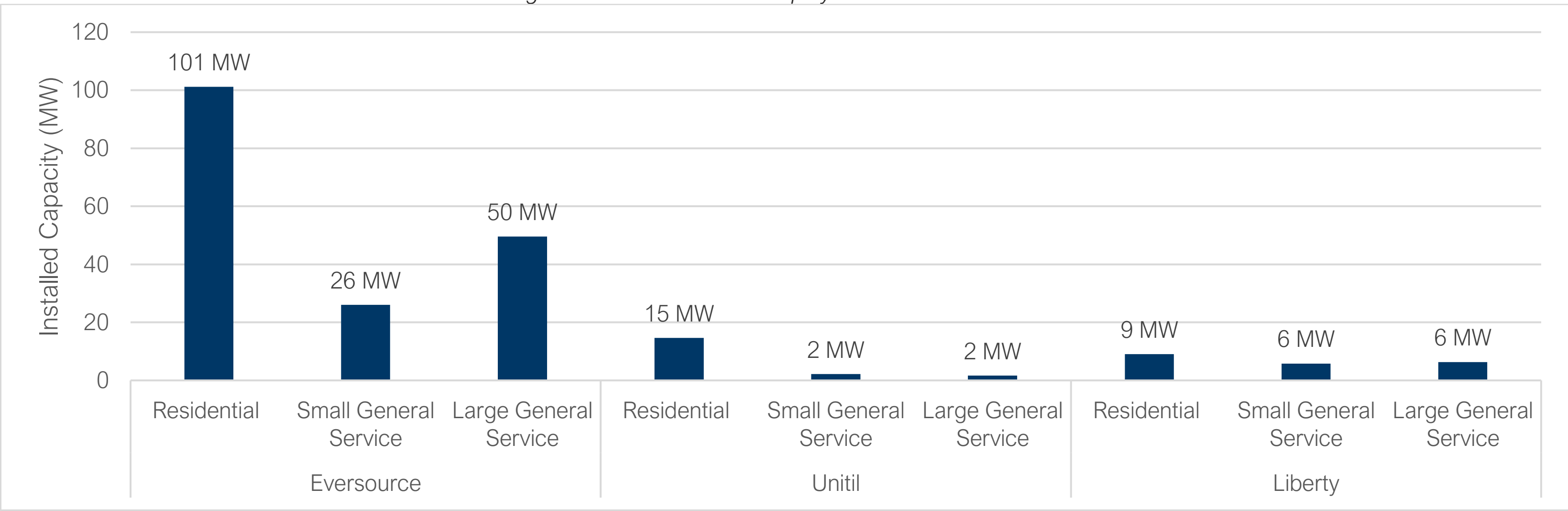
- Generation: Avoided energy, RPS, ancillary services, distribution and transmission line losses, and risk premium are considered pass-through components, while avoided capacity and DRIPE benefits were considered to have an impact on rates.
- Distribution: The avoided distribution costs include avoided distribution CAPEX and OPEX, Distribution Grid Services, T&D System Upgrades, and Resiliency Services.
- Transmission: Transmission Capacity and Transmission Charges are considered for the rate and bill impacts assessments; the rate impacts assessment assumes only the portion attributable to the part of New Hampshire load as a percentage of the ISO-NE system, which is approximately 9.54%.

PV system sizes are based on aggregated utility data (AC kW):

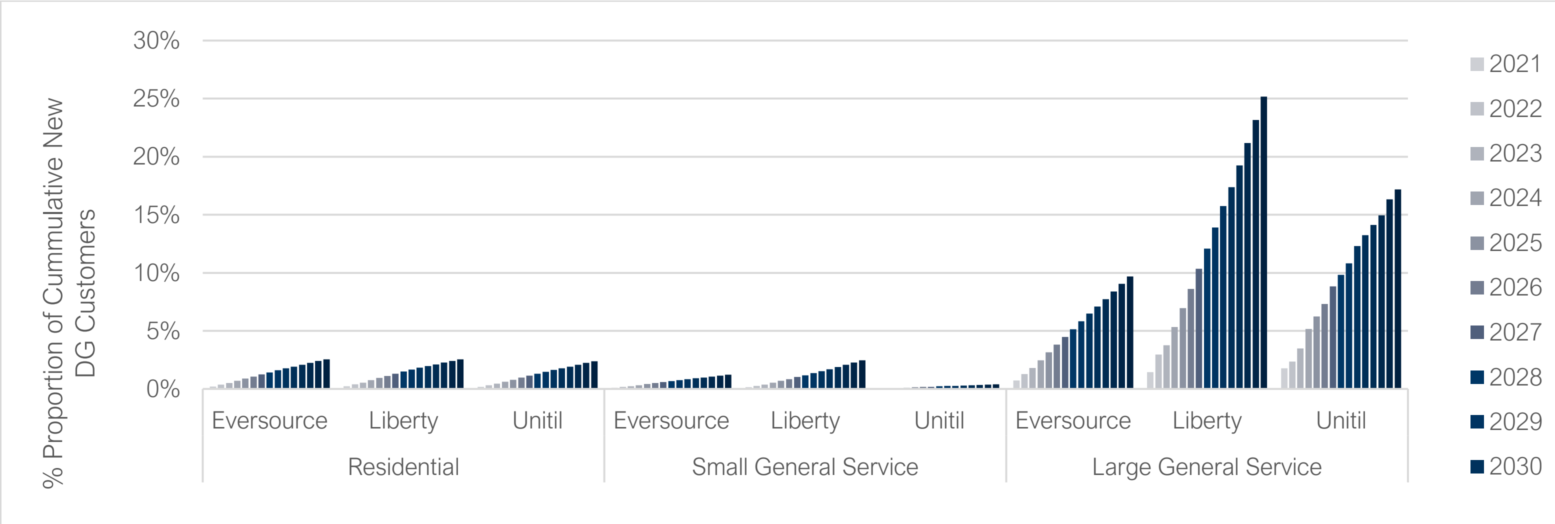
Customer Class	Eversource	Unitil	Liberty	% Self-Consumed
Residential	7.6	12.2	10.1	72% (Monthly Netting)
Small General Service	24.5	43.0	41.3	65% (Monthly Netting)
Large General Service	329.2	47.2	209.6	99% (Hourly Netting)

Incremental DG Capacity deployed over the study period:

Figure 9: Incremental DG Deployed between 2021 - 2035

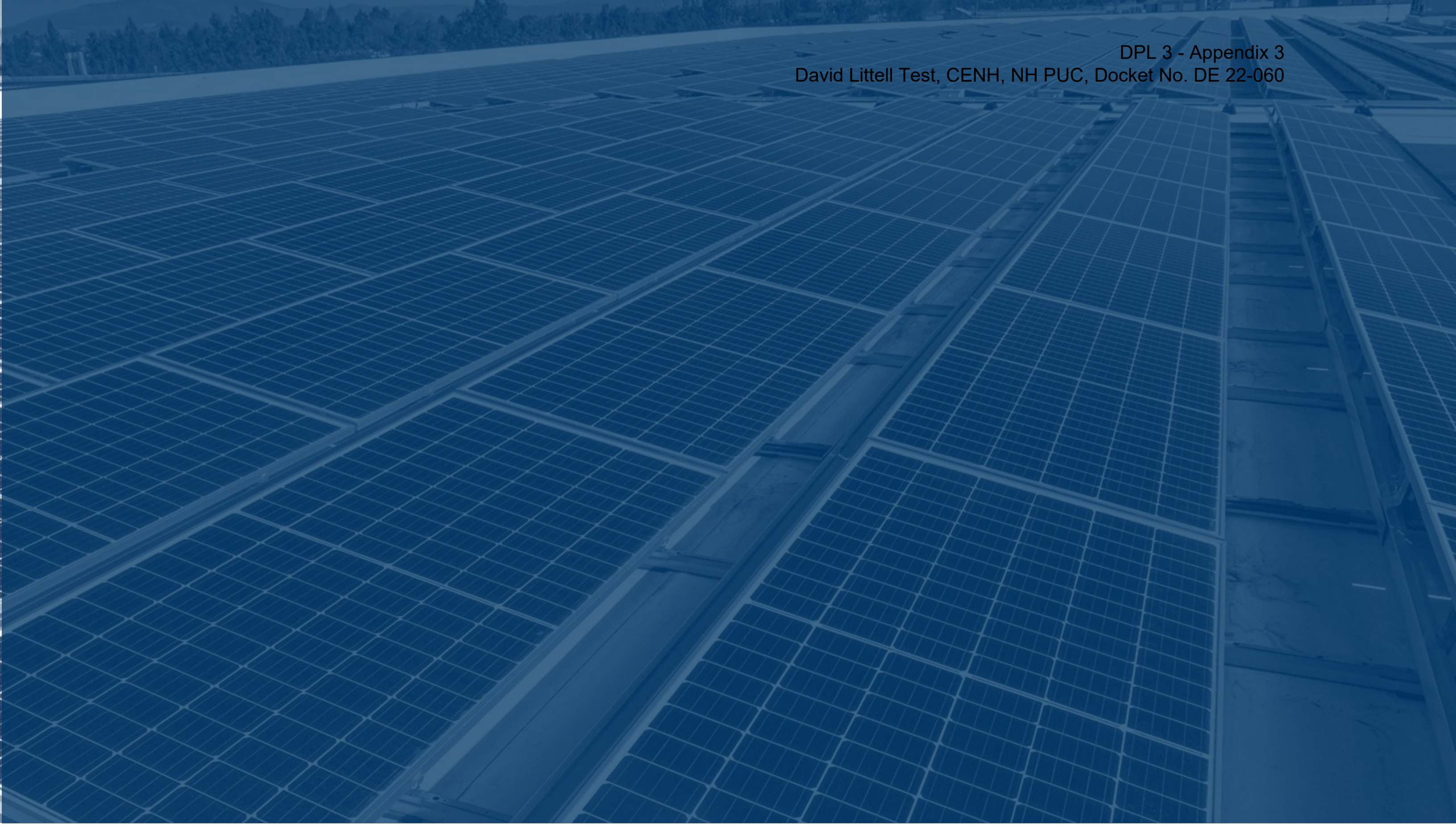


Percentage of customers with DG by 2035:



Inputs	Sources
Load Forecasts by Customer Class (energy, demand, number of customers)	Utility load forecasts
Utility and Rate Class Specific Transmission and Distribution Line Losses[42]	Utility data
Customer Rates	Utility tariffs
DG Projections by Customer Class	Utility load forecasts
DG Program Budgets	Utility interviews
Peak Coincidence by Customer Class	Utility system load data

[42] The utility and rate class specific T&D losses were used to calculate the avoided costs and lost revenues for the rate and bill impact assessment.



New Hampshire Value of Distributed Energy Resources

Addendum

Submitted to:

New Hampshire Department of Energy

New Hampshire Department of Energy

www.energy.nh.gov

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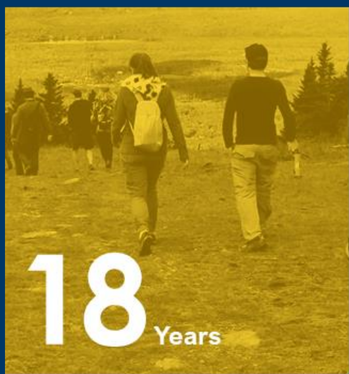
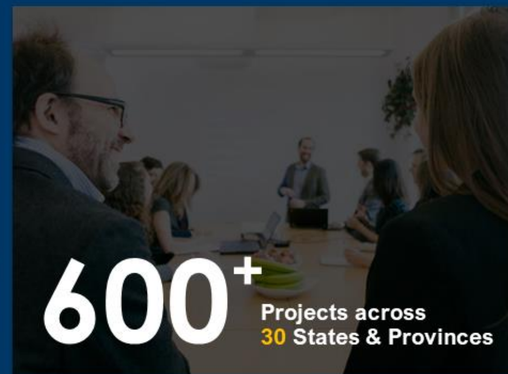
With support from Power Advisory

About Dunsky





Founded in 2004, Dunsky supports leading governments, utilities, corporations and non-profits across North America in their efforts to **accelerate the clean energy transition**, effectively and responsibly.

Working across buildings, industry, energy and mobility, we support our clients through three key services: we **quantify** opportunities (technical, economic, market); **design** go-to-market strategies (plans, programs, policies); and **evaluate** performance (with a view to continuous improvement).

Dunsky is proudly Canadian, with offices and staff in Montreal, Toronto, Vancouver, Ottawa and Halifax.

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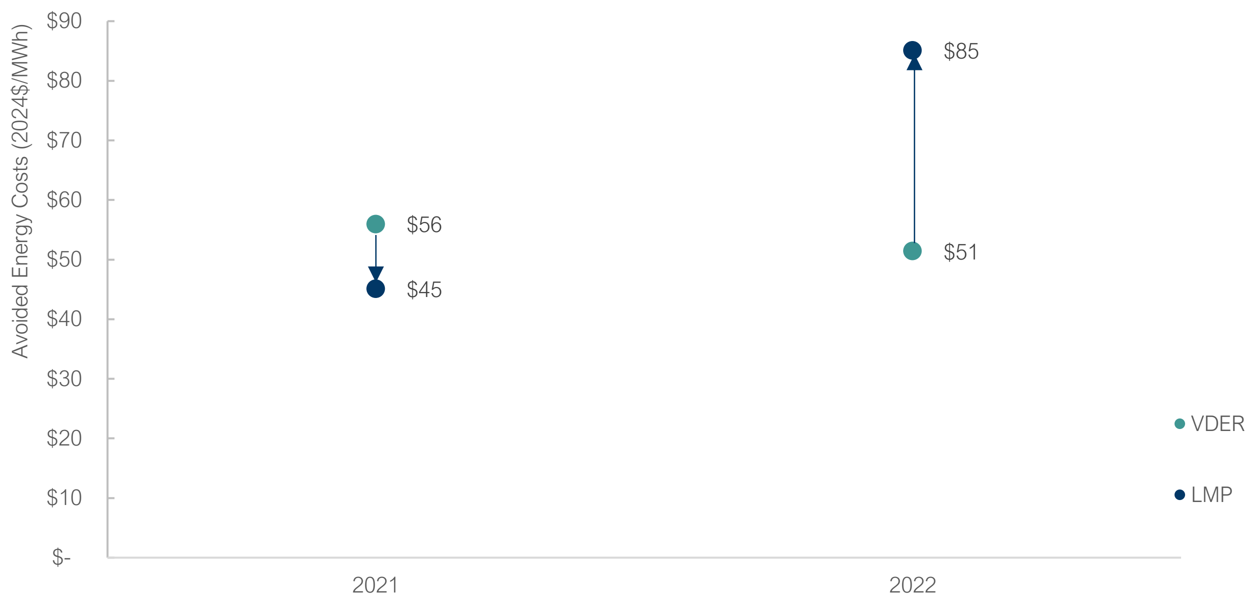
A. Introduction

Since the completion of the New Hampshire Value of Distributed Energy Resources Study Report in October 2022, several factors, such as supply chain constraints caused by COVID-19, strained infrastructure, and the ongoing Russian invasion of Ukraine, have led to an unparalleled surge in natural gas prices and energy supply costs. To provide a more current estimate of the avoided costs captured by distributed energy resources and the resulting study findings, the below addendum updates a number of relevant study values and results.

As seen in the figure below, the historic Locational Marginal Price (LMP) prices in 2021 and 2022 varied significantly compared to the estimates used in the original study. In 2021, the average LMP observed in the ISO-NE market was 20% lower than the avoided energy cost forecasted in the original VDER study. On the other hand, in 2022, the average LMP observed in the ISO-NE market was 66% higher than the avoided energy cost forecasted in the original VDER study. Thus the study results are subject to various factors that can lead to discrepancies between predicted prices and actual historical prices, including constraints in natural gas supply, transmission, and changes in system demand.

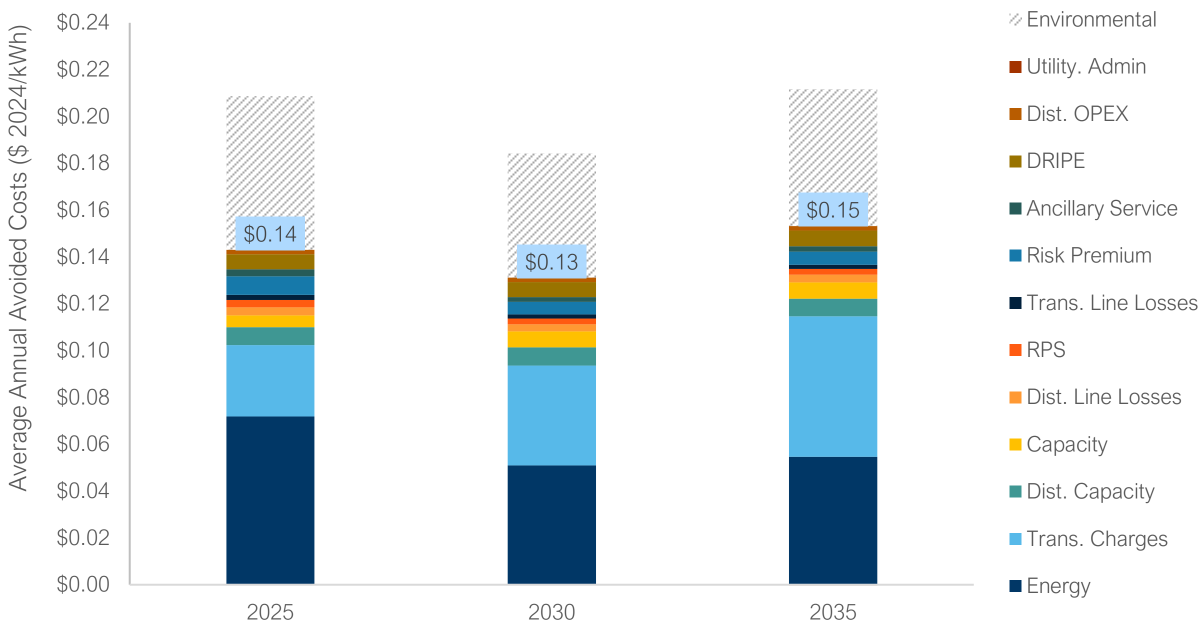
Actual v/s Predicted Avoided Energy Costs



B. Overall Results

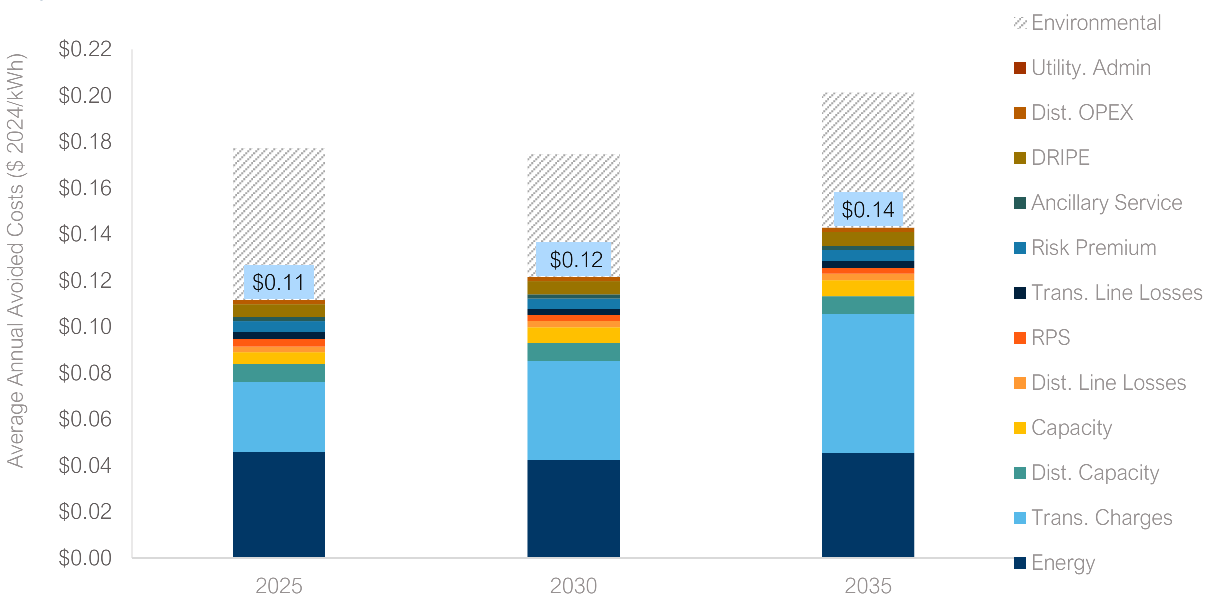
B.1 Comparison Between the Original and Updated Technology Neutral Value Stack

Updated Tech-Neutral Value Stack

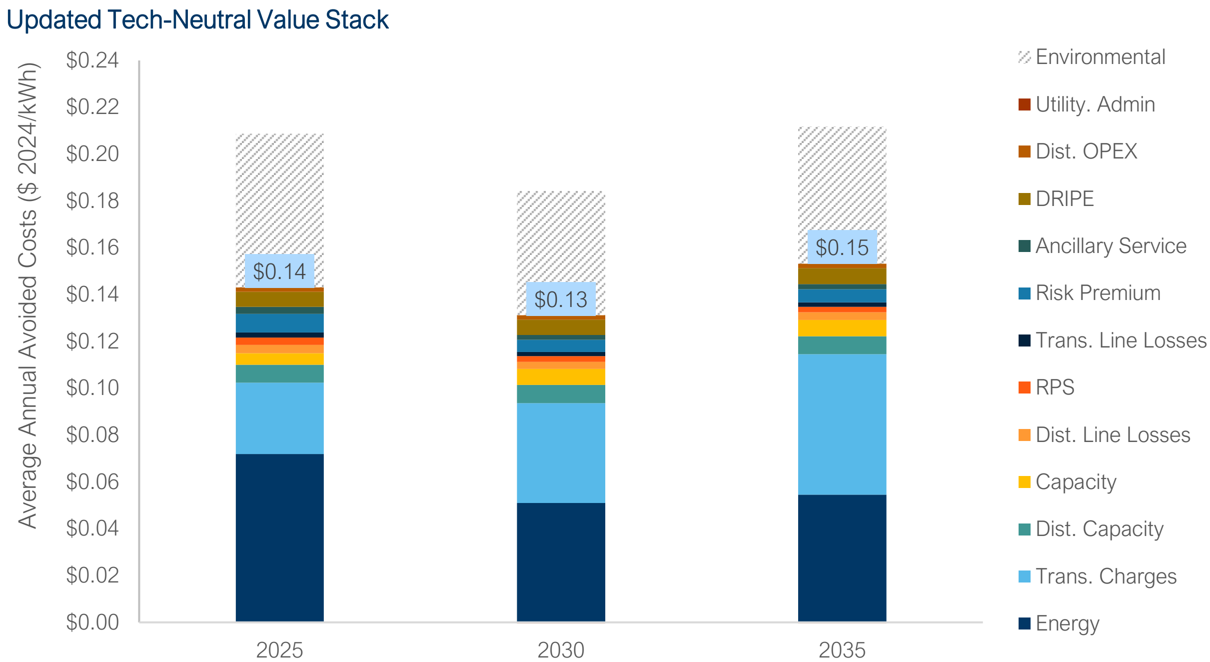


Compared to the original tech-neutral value stack, the total avoided costs (excluding environmental benefits) are, on average, about 17% higher in the initial years and about 5% higher in the later part of the study.

Original Tech-Neutral Value Stack



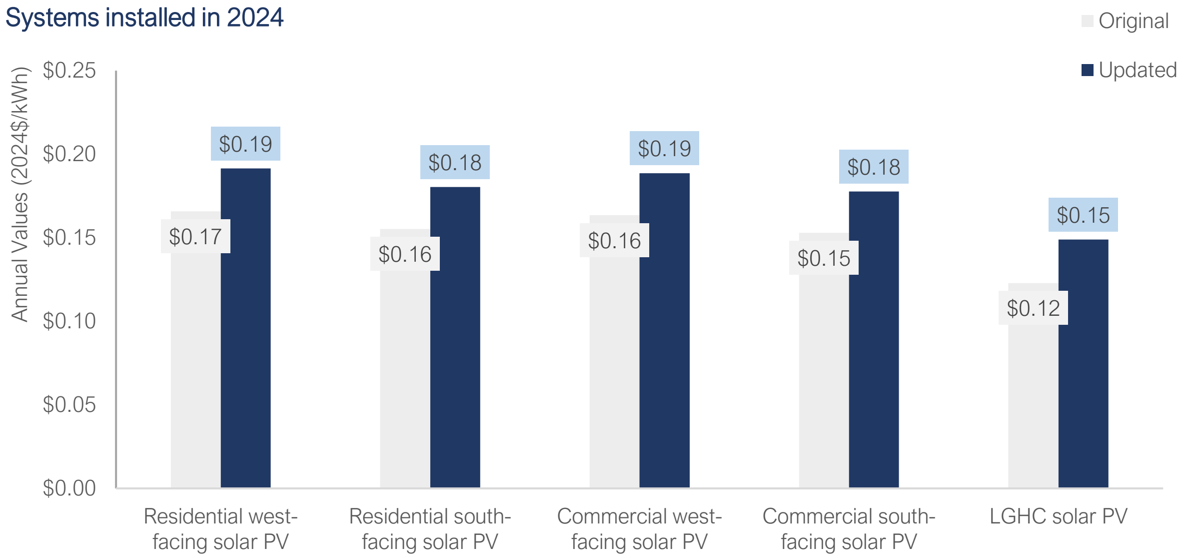
B.2 Updated Technology Neutral Value Stack

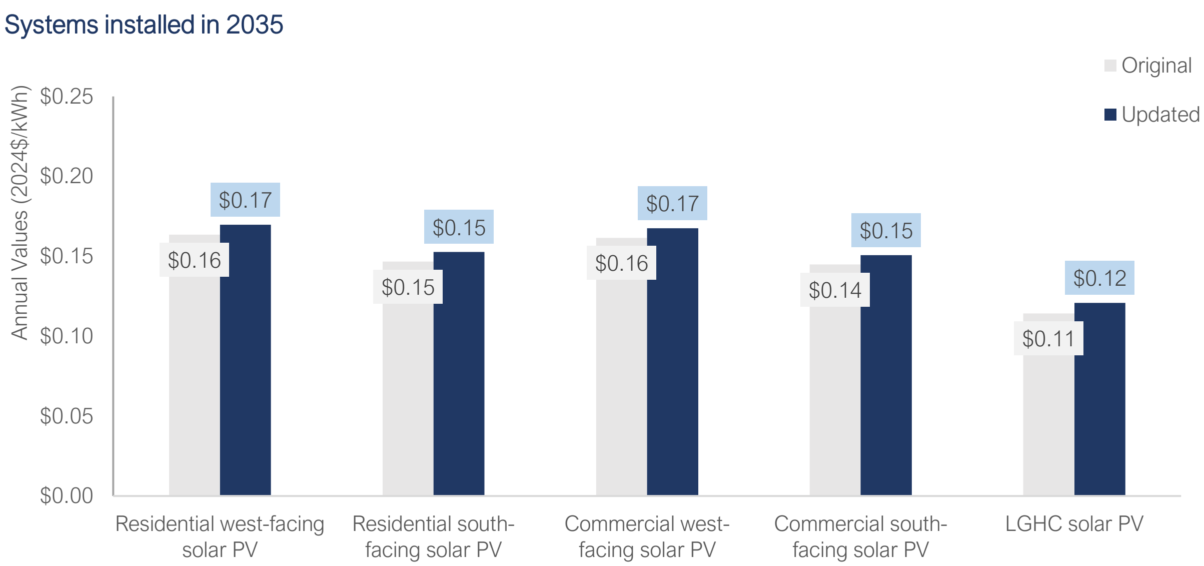


The updated avoided energy costs can make up to 50% of the overall tech-neutral value. Consistent with the original study, this value decreases gradually over time. The current high prices are due to the impact of high natural gas prices, which has been factored into the modified AESC energy forecast. However, the value of energy is expected to decrease over time as lower-cost resources like offshore wind and solar become more prevalent.

Transmission charges are forecasted to increase over time, increasing avoided cost value. Overall, Energy, Transmission Charges, Distribution Capacity, and Capacity Charges represent 80%-85% of the average annual DER avoided costs benefits (excluding environmental).

B.3 Value Captured by Solar PV Systems





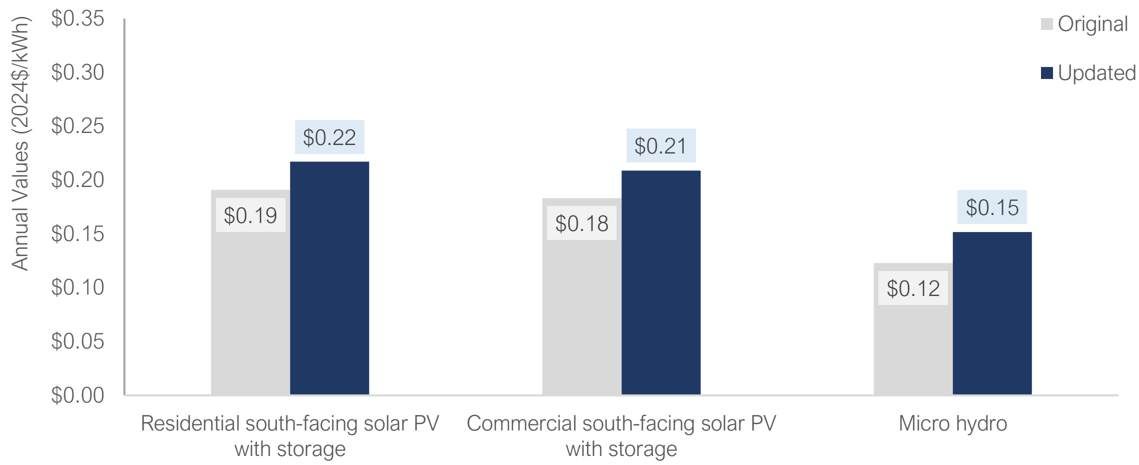
The value of solar-only systems tends to decrease over time due to the decreasing energy avoided costs. However, the updated total avoided costs in 2024 are approximately 15-20% higher than the original study. This increment gradually decreases to 5% by 2035.

Systems facing west can generate 6-11% more avoided cost value. However, the deployment of such systems is anticipated to be limited as customers are presently encouraged to prioritize south-facing installations that maximize volumetric production.

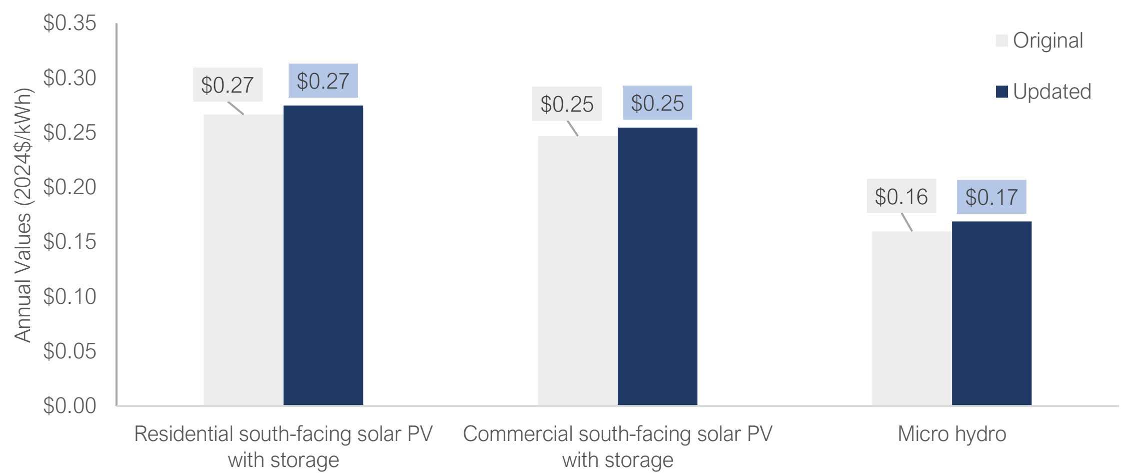
Commercial systems achieve less total value than residential systems. This is primarily due to reduced line loss and reduced RPS avoided cost value (due to a lower % of the energy consumed behind the meter) associated with commercial systems.

B.4 Value Captured by DG Systems

Systems installed in 2024



Systems installed in 2035



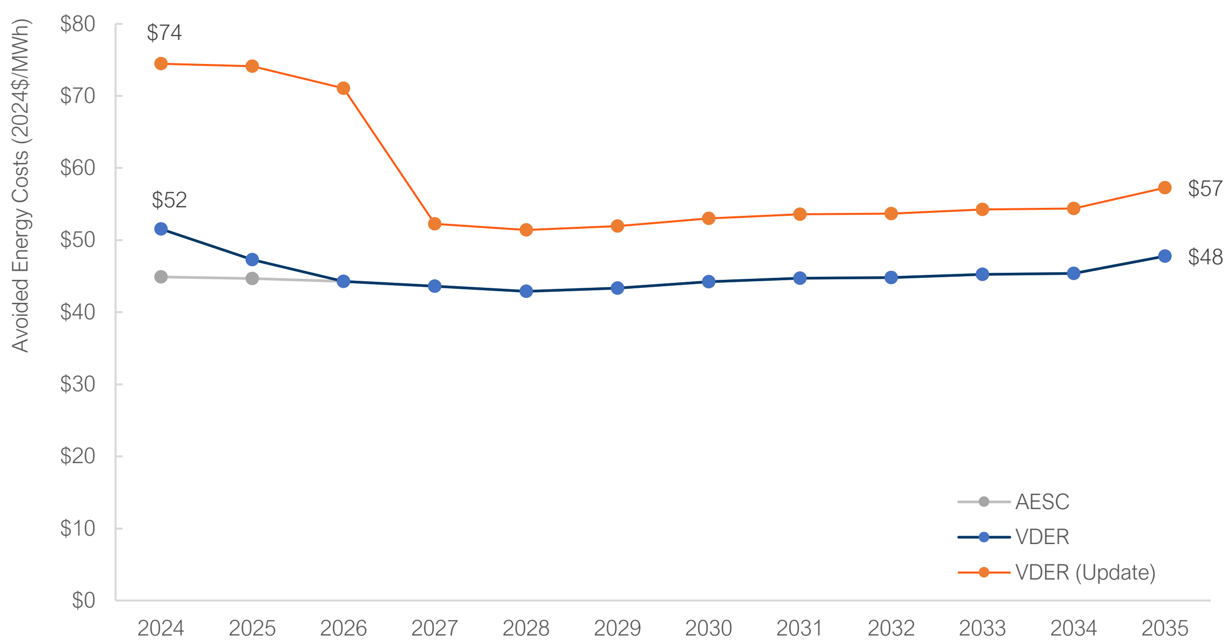
Over time, the value of solar paired with storage and micro-hydro systems increases significantly. The reason behind this is that these systems are able to capture transmission-avoided costs more effectively. Furthermore, as the transmission avoided costs continue to increase over the study period, the overall value captured by these systems also increases. Compared to the original study, solar-coupled storage assets have a total avoided cost of about 13% higher in 2024, whereas micro hydro facilities have an increased updated total avoided cost of 20%.

C. Updates to the Value Stack Components

C.1 Avoided Energy Costs

Key Update: The significant increase in natural gas prices due to COVID-19 and the conflict in Ukraine has resulted in a substantial rise in energy supply costs. To reflect this, the latest natural gas price forecast is being utilized to determine updated projections for wholesale energy costs. Consequently, we anticipate an expected increase of 20-60% in avoided energy costs compared to the initial projections in the VDER study. The results have been updated to reflect $2024 real values[1].

Near term escalations in avoided energy costs



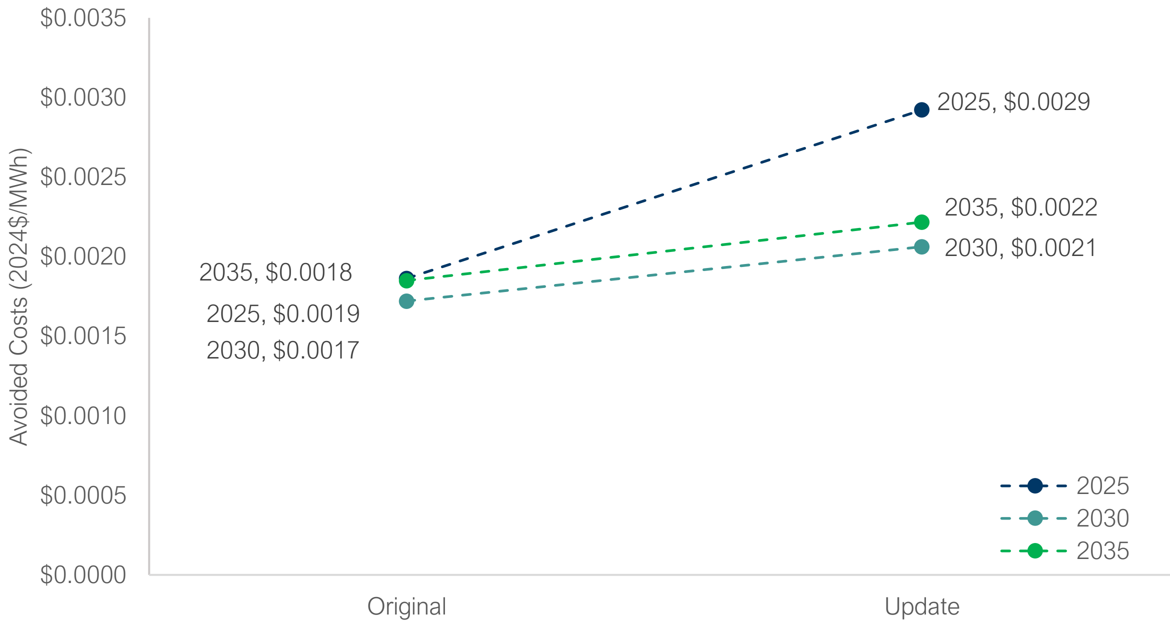
C.2 Avoided Capacity Costs

Key Updates: Updated to $2024 real values.

[1] The $2024 real was estimated based on a change in the CPI from first quarter of 2023 to 2024 based on historical trends. The inflation was based on the relative change in the 2021 CPI (271) to 2024 CPI (estimated 317).

C.3 Ancillary Services and Load Obligation Charges

Key Updates: The model assumes that ancillary services and load obligation charges are tied to energy costs – an update in wholesale energy costs will result in updated values to this value stack component. Further, the results were updated to $2024 real values.



C.4 RPS Compliance

Key Updates: Updated to $2024 real values.

C.5 Transmission Charges

Key Updates: Updated to $2024 real values.

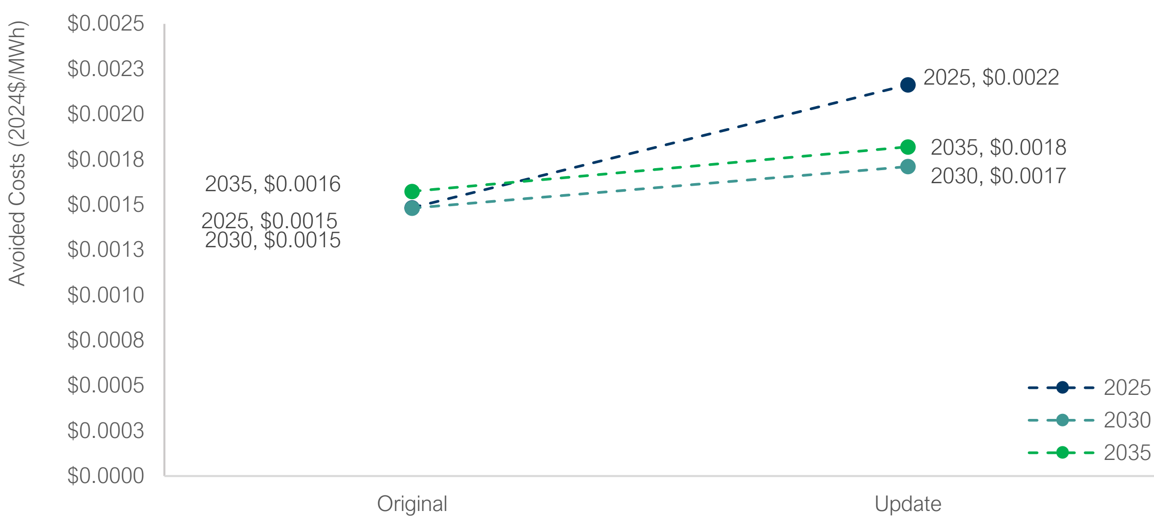
C.6 Distribution System Operating Expenses

Key Updates: Updated to $2024 real values.

C.7 Transmission Line Losses

Key Updates: The avoided transmission line loss is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. An update to wholesale energy costs will result in an update to the avoided transmission line loss component.

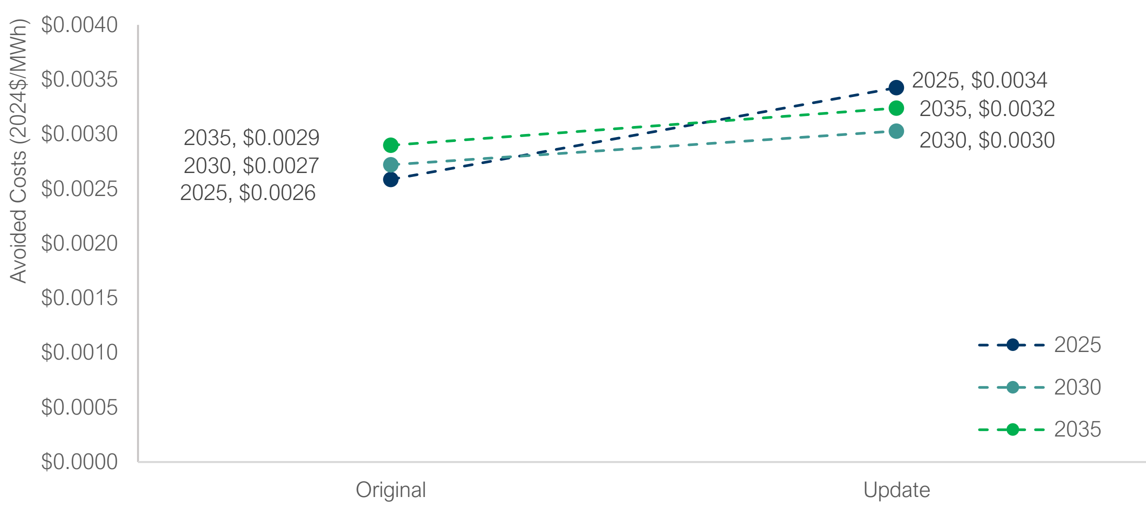
Transmission Line Loss



C.8 Distribution Line Losses

Key Updates: The avoided distribution line loss is a cumulative value, incorporating line loss values from all relevant avoided cost criteria: energy, capacity, and wholesale market price suppression. An update to wholesale energy costs will result in an update to the avoided distribution line loss component.

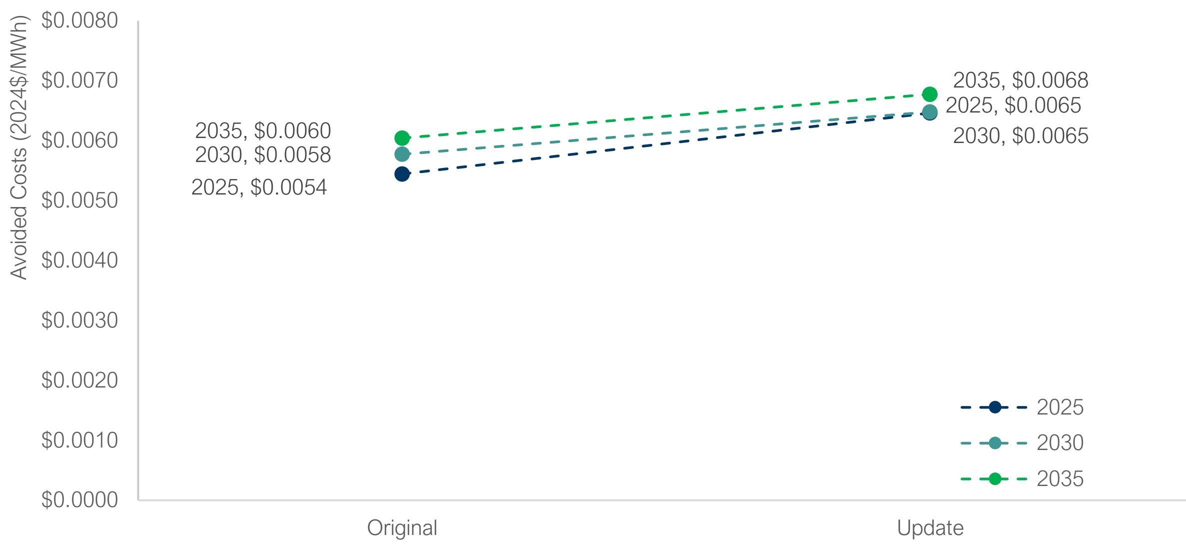
Distribution Line Loss



C.9 Wholesale Market Price Suppression

Key Updates: The electricity produced at the customer-generator's site reduces the overall energy and capacity procured through wholesale, resulting in lower market clearing prices. This price suppression effect, the Demand Reduction Induced Price Effect, or DRIPE, is ultimately passed on to all market participants. Since DRIPE is tied to wholesale energy costs, updated values are provided for this component. Further, the results were updated to $2024 real values.

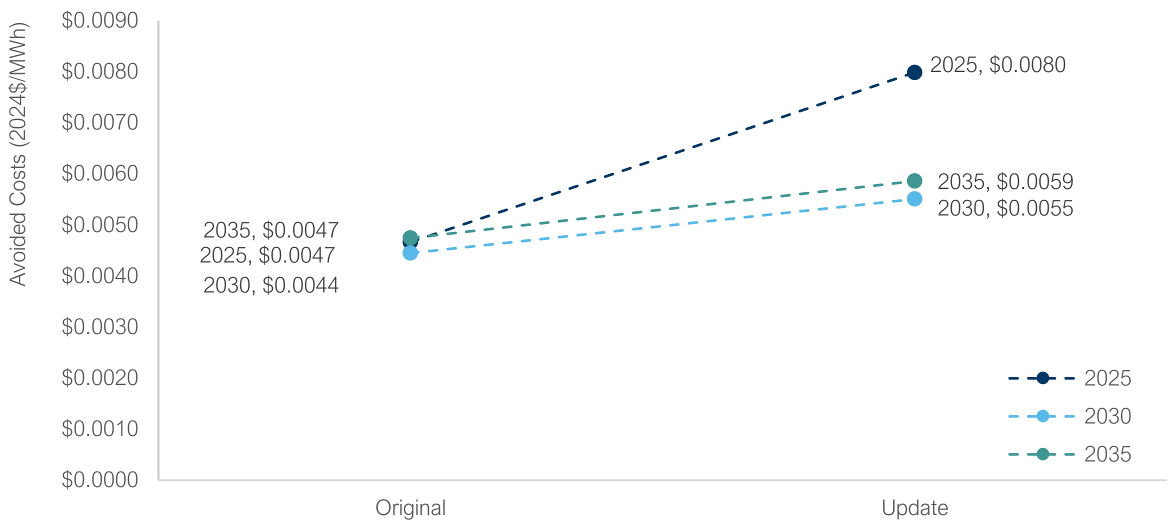
DRIPE



C.10 Wholesale Risk Premium

Key Updates: The full retail price of electricity is generally greater than the sum of the wholesale market prices for energy, capacity, and ancillary services. This is partly because the wholesale suppliers of retail customer load requirements incur various market risks when they set contract prices before supply delivery periods. Therefore, every wholesale energy and capacity obligation reduction may reduce the supplier's cost to mitigate such risks. As a result, an update to wholesale energy and ancillary service costs will result in an update to the wholesale risk premium charges. To account for increased risk in fuel supply in the near term, the near-term wholesale risk premiums were assumed to be 11%, higher than in the original study, leading to higher avoided costs. Over the study period, it was assumed that risk premiums would fall back to the default assumption in the AESC (8%). Further, the results were updated to $2024 real values.

Wholesale Risk Premium



C.11 Distribution Utility Administration Costs

Key Updates: Updated to $2024 real values.

C.12 Environmental Externalities

Key Updates: Updated to $2024 real values.

C.13 Distribution Grid Support Services

Key Updates: Updated to $2024 real values.

C.14 Resilience Services

Key Updates: Updated to $2024 real values.

C.15 Customer Installed Net Costs

Key Updates: Updated to $2024 real values.

D. Results Tables (Updated)

D.1 Technology-Neutral Value Stack

Table 1: Average Annual Technology-Neutral Value Stack ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.073	0.072	0.069	0.051	0.050	0.050	0.051	0.051	0.051	0.052	0.052	0.055
Transmission Charges	0.028	0.030	0.033	0.035	0.037	0.040	0.043	0.046	0.049	0.052	0.056	0.060
Distribution Capacity	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008
Capacity	0.005	0.005	0.005	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.008	0.007
Distribution Line Losses	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.010	0.008	0.007	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Environmental Externality	0.065	0.066	0.064	0.060	0.057	0.057	0.053	0.055	0.055	0.056	0.057	0.058
Total – Excluding Environmental	0.143	0.143	0.140	0.122	0.123	0.127	0.131	0.135	0.138	0.142	0.147	0.153
Total – Including Environmental	0.208	0.208	0.204	0.182	0.180	0.183	0.184	0.189	0.193	0.198	0.204	0.211

Table 2. Average Annual Technology-Neutral Value, Minimum Hourly Value, and Maximum Hourly Value ($/kWh) (2024$)

	2025			2030			2035		
	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)	Average Annual Value ($/kWh)	Minimum Hourly Value ($/kWh)	Maximum Hourly Value ($/kWh)
Energy	0.072	0.0168	0.1409	0.051	-0.0118	0.2030	0.055	-0.0115	0.2229
Transmission Charges	0.030	-	22.8093	0.043	-	32.0500	0.060	-	45.0344
Distribution Capacity	0.008	-	0.7197	0.008	-	0.7183	0.008	-	0.7057
Capacity	0.005	-	43.3843	0.007	-	59.8000	0.007	-	60.9725
Distribution Line Losses	0.003	0.0003	5.8434	0.003	-0.0001	6.7546	0.003	-0.0001	6.8874
RPS	0.003	0.0032	0.0032	0.002	0.0025	0.0025	0.002	0.0024	0.0024
Transmission Line Losses	0.002	0.0004	1.9425	0.002	-0.0003	2.2448	0.002	-0.0003	2.2890
Risk Premium	0.008	0.0017	1.4468	0.006	-0.0010	0.8698	0.006	-0.0009	0.9733
Ancillary Services	0.003	0.0005	0.0095	0.002	-0.0008	0.0082	0.002	-0.0008	0.0129
DRIPE	0.006	0.0002	8.3451	0.006	-0.0009	9.4254	0.007	-0.0009	10.0161
Distribution OPEX	0.002	-	0.1741	0.002	-	0.1741	0.002	-	0.1741
Utility Admin	-	-0.0019	-	-	-0.0020	-	-	-0.0020	-
Environmental Externality	0.066	-0.0094	0.1875	0.053	-	0.1399	0.058	-	0.1315

D.2 Residential and Commercial Solar PV

Table 3. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.065	0.062	0.058	0.041	0.038	0.038	0.038	0.038	0.037	0.037	0.037	0.040
Transmission Charges	0.042	0.044	0.047	0.045	0.048	0.052	0.055	0.058	0.049	0.041	0.044	0.043
Distribution Capacity	0.022	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.018	0.019	0.018	0.023	0.023	0.023	0.026	0.026	0.026	0.027	0.030	0.026
Distribution Line Losses	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.011	0.009	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.057	0.054	0.048	0.044	0.039	0.038	0.036	0.036	0.036	0.037	0.038	0.041
Total – Excluding Environmental	0.185	0.183	0.178	0.161	0.161	0.164	0.169	0.172	0.161	0.155	0.161	0.157
Total – Including Environmental	0.242	0.237	0.225	0.205	0.200	0.203	0.205	0.207	0.197	0.192	0.199	0.198

Table 4. Average Annual Avoided Cost Value for Residential West-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.066	0.064	0.059	0.042	0.040	0.039	0.039	0.039	0.039	0.039	0.039	0.041
Transmission Charges	0.047	0.049	0.052	0.048	0.051	0.054	0.057	0.061	0.050	0.046	0.049	0.051
Distribution Capacity	0.025	0.024	0.025	0.025	0.025	0.025	0.024	0.024	0.023	0.023	0.023	0.023
Capacity	0.020	0.021	0.020	0.025	0.025	0.026	0.028	0.029	0.029	0.030	0.033	0.028
Distribution Line Losses	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.006	0.005
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.011	0.009	0.008	0.007	0.006	0.006	0.007	0.007	0.007	0.007	0.007	0.007
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Utility Admin	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.057	0.055	0.049	0.046	0.042	0.041	0.038	0.038	0.039	0.040	0.040	0.043
Total – Excluding Environmental	0.196	0.195	0.191	0.172	0.172	0.175	0.181	0.184	0.171	0.169	0.175	0.174
Total – Including Environmental	0.253	0.250	0.240	0.218	0.214	0.216	0.219	0.222	0.210	0.208	0.216	0.217

Table 5. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.065	0.062	0.058	0.041	0.038	0.038	0.038	0.038	0.037	0.037	0.037	0.040
Transmission Charges	0.042	0.044	0.047	0.045	0.048	0.052	0.055	0.058	0.049	0.041	0.044	0.043
Distribution Capacity	0.022	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.018	0.019	0.018	0.023	0.023	0.023	0.026	0.026	0.026	0.027	0.030	0.026
Distribution Line Losses	0.003	0.004	0.003	0.004	0.003	0.004	0.004	0.004	0.004	0.004	0.004	0.004
RPS	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Transmission Line Losses	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.011	0.009	0.007	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.006
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.057	0.054	0.048	0.044	0.039	0.038	0.036	0.036	0.036	0.037	0.038	0.041
Total – No Environmental	0.182	0.180	0.175	0.159	0.159	0.162	0.167	0.170	0.159	0.153	0.159	0.155
Total – Including Environmental	0.239	0.234	0.223	0.203	0.198	0.201	0.203	0.205	0.195	0.190	0.197	0.196

Table 6. Average Annual Avoided Cost Value for Commercial West-Facing Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.066	0.064	0.059	0.042	0.040	0.039	0.039	0.039	0.039	0.039	0.039	0.041
Transmission Charges	0.047	0.049	0.052	0.048	0.051	0.054	0.057	0.061	0.050	0.046	0.049	0.051
Distribution Capacity	0.025	0.024	0.025	0.025	0.025	0.025	0.024	0.024	0.023	0.023	0.023	0.023
Capacity	0.020	0.021	0.020	0.025	0.025	0.026	0.028	0.029	0.029	0.030	0.033	0.028
Distribution Line Losses	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.004
RPS	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.011	0.009	0.008	0.007	0.006	0.006	0.007	0.007	0.006	0.007	0.007	0.007
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006
Utility Admin	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.057	0.055	0.049	0.046	0.042	0.041	0.038	0.038	0.039	0.040	0.040	0.043
Total – No Environmental	0.193	0.192	0.188	0.170	0.170	0.173	0.179	0.181	0.169	0.167	0.173	0.172
Total – Including Environmental	0.250	0.247	0.237	0.216	0.211	0.214	0.217	0.220	0.208	0.206	0.214	0.215

Table 7. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.045	-	0.003	0.117	0.103	0.025	-	0.002	0.035	0.026
	7	0.047	-	0.003	0.096	0.081	0.029	-	0.002	0.051	0.042
	8	0.058	-	0.004	0.068	0.051	0.033	-	0.002	0.044	0.034
	9	0.060	-	0.004	0.066	0.049	0.031	-	0.002	0.037	0.028
	10	0.059	-	0.004	0.061	0.045	0.025	-	0.002	0.025	0.017
	11	0.057	-	0.004	0.055	0.039	0.022	-	0.002	0.022	0.014
	12	0.057	-	0.004	0.057	0.041	0.023	-	0.002	0.026	0.018
	13	0.057	-	0.004	0.056	0.040	0.023	-	0.002	0.027	0.019
	14	0.058	-	0.223	0.057	0.041	0.023	-	0.002	0.027	0.019
	15	0.059	-	0.004	0.059	0.043	0.024	-	0.002	0.025	0.016
	16	0.061	-	0.004	0.068	0.051	0.030	-	0.002	0.035	0.025
	17	0.064	-	0.004	0.081	0.063	0.041	-	0.003	0.067	0.055
	18	0.064	-	0.004	0.082	0.063	0.048	-	0.003	0.086	0.072
	19	0.061	-	0.077	0.072	0.054	0.051	-	0.004	0.089	0.075
	20	0.055	-	0.004	0.062	0.044	0.049	-	0.003	0.093	0.079
	21	0.054	-	0.004	0.051	0.033	0.049	-	1.361	0.093	0.078
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 8. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.047	-	0.003	0.116	0.103	0.032	-	0.002	0.061	0.053
	7	0.048	-	0.003	0.096	0.082	0.038	-	0.003	0.071	0.061
	8	0.055	-	0.004	0.085	0.069	0.042	-	0.003	0.064	0.053
	9	0.055	-	0.004	0.080	0.064	0.042	-	0.003	0.064	0.053
	10	0.055	-	0.006	0.078	0.063	0.040	-	0.006	0.058	0.048
	11	0.055	-	0.051	0.077	0.061	0.038	-	0.050	0.054	0.044
	12	0.056	-	0.073	0.078	0.062	0.039	-	0.071	0.056	0.046
	13	0.056	-	0.086	0.077	0.061	0.041	-	0.084	0.059	0.049
	14	0.056	-	0.355	0.078	0.062	0.042	-	0.612	0.063	0.053
	15	0.057	0.433	0.675	0.183	0.064	0.042	0.663	0.233	0.071	0.052
	16	0.058	-	0.124	0.080	0.063	0.046	-	0.122	0.071	0.059
	17	0.059	-	0.121	0.074	0.057	0.055	-	1.098	0.198	0.070
	18	0.060	-	0.095	0.062	0.044	0.063	-	0.094	0.089	0.073
	19	0.060	-	0.067	0.058	0.040	0.071	-	0.067	0.087	0.070
	20	0.059	-	0.012	0.064	0.046	0.066	-	0.012	0.089	0.073
	21	0.058	-	0.004	0.063	0.046	0.059	-	0.004	0.088	0.073
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 9. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.049	-	0.003	0.087	0.072	0.044	-	0.003	0.081	0.070
	8	0.060	-	0.004	0.085	0.066	0.051	-	0.004	0.079	0.065
	9	0.060	-	0.004	0.083	0.064	0.050	-	0.004	0.072	0.058
	10	0.059	-	0.004	0.083	0.065	0.043	-	0.003	0.059	0.046
	11	0.058	-	0.004	0.081	0.063	0.042	-	0.003	0.056	0.044
	12	0.058	-	0.004	0.080	0.063	0.043	-	0.003	0.059	0.047
	13	0.058	-	0.004	0.079	0.062	0.044	-	0.003	0.064	0.051
	14	0.057	-	0.004	0.080	0.062	0.045	-	0.003	0.069	0.056
	15	0.056	-	0.004	0.081	0.064	0.044	-	0.003	0.067	0.054
	16	0.055	-	0.004	0.079	0.062	0.048	-	0.003	0.081	0.067
	17	0.054	-	0.466	0.071	0.054	0.051	-	0.004	0.094	0.080
	18	0.053	-	0.007	0.055	0.038	0.052	-	0.003	0.095	0.081
	19	0.053	-	0.003	0.053	0.038	0.052	-	0.003	0.096	0.083
	20	0.053	-	0.003	0.047	0.031	0.051	-	1.505	0.096	0.083
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 10. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Installed in 2024 – Winter($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.116	-	0.007	0.093	0.063	0.078	-	0.005	0.086	0.067
	8	0.123	-	0.008	0.104	0.071	0.085	-	0.006	0.089	0.067
	9	0.121	-	0.008	0.102	0.069	0.085	-	0.006	0.086	0.063
	10	0.119	-	0.008	0.098	0.066	0.071	-	0.005	0.067	0.048
	11	0.117	-	0.008	0.095	0.064	0.067	-	0.005	0.061	0.042
	12	0.117	-	0.008	0.095	0.063	0.066	-	0.005	0.062	0.043
	13	0.117	-	0.008	0.095	0.064	0.065	-	0.005	0.061	0.042
	14	0.118	-	0.008	0.096	0.064	0.067	-	0.005	0.063	0.044
	15	0.119	-	0.008	0.098	0.065	0.068	-	0.005	0.062	0.042
	16	0.122	-	0.008	0.102	0.067	0.078	-	0.006	0.077	0.055
	17	0.126	-	0.008	0.102	0.068	0.094	-	0.007	0.100	0.076
	18	0.127	-	0.008	0.106	0.073	0.099	-	0.007	0.104	0.080
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

D.3 Residential and Commercial Solar PV Paired with Storage

Table 11. Average Annual Avoided Cost Value for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.067	0.066	0.063	0.045	0.045	0.045	0.046	0.046	0.046	0.046	0.047	0.049
Transmission Charges	0.075	0.085	0.091	0.092	0.098	0.104	0.111	0.118	0.120	0.126	0.134	0.149
Distribution Capacity	0.023	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.019	0.020	0.020	0.025	0.024	0.025	0.027	0.028	0.028	0.029	0.032	0.027
Distribution Line Losses	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.006
RPS	0.003	0.003	0.003	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.003	0.003	0.003	0.003	0.003
Risk Premium	0.011	0.009	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.008	0.008
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.009	0.009	0.008	0.008	0.008	0.008	0.008	0.009	0.010	0.010	0.010	0.010
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Environmental Externality	0.055	0.058	0.057	0.053	0.052	0.052	0.048	0.050	0.050	0.051	0.052	0.053
Total – Excluding Environmental	0.222	0.231	0.230	0.216	0.221	0.228	0.238	0.248	0.249	0.257	0.269	0.281
Total – Including Environmental	0.277	0.289	0.287	0.270	0.273	0.281	0.286	0.297	0.299	0.307	0.321	0.334

Table 12. Average Annual Avoided Cost Value for Commercial South-Facing Solar PV Array Paired with Storage Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.067	0.065	0.062	0.045	0.044	0.044	0.045	0.045	0.045	0.045	0.045	0.048
Transmission Charges	0.070	0.079	0.084	0.085	0.090	0.096	0.102	0.109	0.109	0.113	0.121	0.133
Distribution Capacity	0.023	0.022	0.023	0.023	0.023	0.023	0.022	0.022	0.021	0.021	0.021	0.021
Capacity	0.019	0.020	0.020	0.024	0.024	0.025	0.027	0.028	0.027	0.029	0.032	0.027
Distribution Line Losses	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.005	0.004
RPS	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001
Transmission Line Losses	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.003
Risk Premium	0.011	0.009	0.008	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.009	0.009	0.008	0.008	0.008	0.008	0.008	0.009	0.009	0.009	0.009	0.009
Distribution OPEX	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Utility Admin	0.000	0.000	0.000	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.056	0.058	0.055	0.052	0.050	0.050	0.047	0.048	0.048	0.049	0.050	0.051
Total – Excluding Environmental	0.214	0.221	0.220	0.206	0.210	0.217	0.226	0.234	0.234	0.240	0.251	0.260
Total – Including Environmental	0.269	0.279	0.275	0.258	0.260	0.267	0.272	0.282	0.282	0.288	0.301	0.312

Table 13. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.045	-	0.003	0.117	0.103	0.025	-	0.002	0.035	0.026
	7	0.047	-	0.003	0.096	0.081	0.029	-	0.002	0.051	0.042
	8	0.058	-	0.004	0.068	0.051	0.033	-	0.002	0.044	0.034
	9	0.060	-	0.004	0.066	0.049	0.031	-	0.002	0.037	0.028
	10	0.059	-	0.004	0.061	0.045	0.025	-	0.002	0.025	0.017
	11	0.056	-	0.004	0.056	0.040	0.022	-	0.002	0.022	0.015
	12	0.057	-	0.004	0.057	0.042	0.023	-	0.002	0.026	0.019
	13	0.057	-	0.004	0.056	0.040	0.023	-	0.002	0.028	0.020
	14	0.058	-	0.227	0.057	0.041	0.023	-	0.002	0.027	0.019
	15	0.059	-	0.004	0.059	0.043	0.024	-	0.002	0.025	0.016
	16	0.061	-	0.004	0.068	0.051	0.030	-	0.002	0.035	0.025
	17	0.064	-	0.004	0.081	0.063	0.041	-	0.003	0.067	0.055
	18	0.067	-	0.004	0.084	0.064	0.050	-	0.003	0.085	0.071
	19	0.068	-	0.202	0.080	0.060	0.056	-	0.004	0.086	0.070
	20	0.068	-	0.004	0.077	0.058	0.057	-	0.451	0.086	0.071
	21	0.069	-	0.221	0.075	0.055	0.057	-	0.919	0.089	0.073
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 14. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.047	-	0.003	0.116	0.103	0.032	-	0.002	0.061	0.053
	7	0.048	-	0.003	0.096	0.082	0.038	-	0.003	0.071	0.061
	8	0.055	-	0.004	0.085	0.069	0.042	-	0.003	0.064	0.053
	9	0.055	-	0.004	0.080	0.064	0.042	-	0.003	0.064	0.053
	10	0.055	-	0.006	0.078	0.063	0.040	-	0.006	0.058	0.048
	11	0.055	-	0.051	0.077	0.061	0.038	-	0.049	0.053	0.044
	12	0.056	-	0.073	0.078	0.062	0.039	-	0.071	0.057	0.046
	13	0.056	-	0.088	0.077	0.061	0.041	-	0.085	0.060	0.049
	14	0.056	-	0.358	0.078	0.062	0.042	-	0.618	0.063	0.053
	15	0.057	0.433	0.675	0.183	0.064	0.042	0.663	0.233	0.071	0.052
	16	0.058	-	0.124	0.080	0.063	0.046	-	0.122	0.071	0.059
	17	0.059	-	0.122	0.074	0.057	0.055	-	1.106	0.201	0.070
	18	0.060	-	0.098	0.062	0.044	0.064	-	0.097	0.089	0.073
	19	0.060	-	0.072	0.058	0.040	0.072	-	0.072	0.088	0.070
	20	0.060	-	0.020	0.064	0.046	0.069	-	0.021	0.091	0.073
	21	0.058	-	0.004	0.063	0.046	0.059	-	0.004	0.088	0.073
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 15. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	0.049	-	0.003	0.087	0.072	0.044	-	0.003	0.081	0.070
	8	0.060	-	0.004	0.085	0.066	0.051	-	0.004	0.079	0.065
	9	0.060	-	0.004	0.083	0.064	0.050	-	0.004	0.072	0.058
	10	0.059	-	0.004	0.083	0.065	0.043	-	0.003	0.059	0.046
	11	0.046	-	0.003	0.071	0.059	0.029	-	0.002	0.040	0.033
	12	0.052	-	0.003	0.077	0.062	0.036	-	0.003	0.050	0.040
	13	0.051	-	0.003	0.077	0.062	0.037	-	0.003	0.056	0.046
	14	0.045	-	0.003	0.073	0.061	0.032	-	0.002	0.057	0.049
	15	0.056	-	0.004	0.081	0.064	0.044	-	0.003	0.067	0.054
	16	0.055	-	0.004	0.079	0.062	0.048	-	0.003	0.081	0.067
	17	0.053	-	0.578	0.069	0.053	0.051	-	0.003	0.094	0.080
	18	0.061	-	0.211	0.061	0.041	0.059	-	0.004	0.093	0.076
	19	0.062	-	0.004	0.056	0.036	0.060	-	0.488	0.093	0.076
	20	0.062	-	0.238	0.060	0.040	0.060	-	0.994	0.095	0.077
	21	0.066	-	0.005	0.078	0.056	0.063	-	0.005	0.097	0.078
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 16. Average Hourly Seasonal Avoided Cost Values for Residential South-Facing Solar PV Array Paired with Storage Installed in 2024 - Winter($/kWh) (2024$)

			2024					2035				
Season		Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter		1	-	-	-	-	-	-	-	-	-	-
		2	-	-	-	-	-	-	-	-	-	-
		3	-	-	-	-	-	-	-	-	-	-
		4	-	-	-	-	-	-	-	-	-	-
		5	-	-	-	-	-	-	-	-	-	-
		6	-	-	-	-	-	-	-	-	-	-
		7	0.116	-	0.007	0.093	0.063	0.078	-	0.005	0.086	0.067
		8	0.123	-	0.008	0.104	0.071	0.085	-	0.006	0.089	0.067
		9	0.121	-	0.008	0.102	0.069	0.085	-	0.006	0.086	0.063
		10	0.119	-	0.008	0.098	0.066	0.071	-	0.005	0.067	0.048
		11	0.116	-	0.008	0.098	0.066	0.074	-	0.005	0.071	0.050
		12	0.113	-	0.007	0.102	0.069	0.084	-	0.006	0.085	0.062
		13	0.113	-	0.007	0.100	0.067	0.085	-	0.006	0.087	0.063
		14	0.115	-	0.008	0.098	0.066	0.079	-	0.006	0.081	0.058
		15	0.119	-	0.008	0.098	0.065	0.068	-	0.005	0.062	0.042
		16	0.122	-	0.008	0.102	0.067	0.078	-	0.006	0.077	0.055
		17	0.126	-	0.008	0.102	0.068	0.094	-	0.007	0.100	0.076
		18	0.124	-	0.229	0.095	0.060	0.107	-	0.007	0.105	0.077
		19	0.124	-	0.466	0.095	0.059	0.108	-	1.443	0.107	0.078
		20	0.123	-	0.008	0.101	0.065	0.107	-	0.007	0.109	0.080
		21	0.123	-	0.008	0.105	0.070	0.105	-	0.007	0.111	0.082
		22	-	-	-	-	-	-	-	-	-	-
		23	-	-	-	-	-	-	-	-	-	-
		24	-	-	-	-	-	-	-	-	-	-

D.4 Large Group Host Commercial Solar PV

Table 17. Average Annual Avoided Cost Value for Large Group Host Commercial Solar PV Array Installed in 2024 ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.070	0.067	0.063	0.045	0.042	0.041	0.042	0.041	0.040	0.041	0.040	0.043
Transmission Charges	0.028	0.030	0.031	0.029	0.031	0.033	0.035	0.037	0.031	0.027	0.029	0.030
Distribution Capacity	0.015	0.015	0.016	0.016	0.016	0.016	0.015	0.015	0.015	0.015	0.014	0.014
Capacity	0.012	0.013	0.013	0.016	0.016	0.016	0.018	0.018	0.018	0.019	0.021	0.018
Distribution Line Losses	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
RPS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transmission Line Losses	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.010	0.008	0.007	0.006	0.005	0.005	0.005	0.005	0.005	0.005	0.006	0.006
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.006	0.006	0.006	0.006	0.007
Distribution OPEX	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Utility Admin	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001	-0.001
Environmental Externality	0.059	0.056	0.050	0.046	0.041	0.041	0.038	0.038	0.038	0.039	0.040	0.043
Total – Excluding Environmental	0.152	0.149	0.144	0.124	0.123	0.125	0.128	0.129	0.122	0.120	0.123	0.124
Total – Including Environmental	0.211	0.205	0.194	0.170	0.164	0.165	0.166	0.167	0.160	0.159	0.163	0.166

Table 18. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.045	-	0.001	0.108	0.097	0.026	-	0.001	0.037	0.030
	6	0.044	-	0.001	0.095	0.084	0.024	-	0.001	0.029	0.022
	7	0.055	-	0.001	0.086	0.073	0.032	-	0.001	0.048	0.040
	8	0.063	-	0.002	0.065	0.051	0.035	-	0.001	0.042	0.034
	9	0.062	-	0.002	0.062	0.049	0.032	-	0.001	0.035	0.028
	10	0.060	-	0.002	0.057	0.044	0.025	-	0.001	0.023	0.017
	11	0.058	-	0.002	0.050	0.038	0.022	-	0.001	0.019	0.014
	12	0.058	-	0.002	0.053	0.041	0.023	-	0.001	0.023	0.018
	13	0.058	-	0.002	0.052	0.039	0.023	-	0.001	0.024	0.019
	14	0.058	-	0.218	0.054	0.041	0.024	-	0.001	0.024	0.019
	15	0.059	-	0.002	0.056	0.042	0.024	-	0.001	0.022	0.016
	16	0.061	-	0.002	0.064	0.050	0.030	-	0.001	0.032	0.025
	17	0.065	-	0.002	0.078	0.063	0.042	-	0.001	0.065	0.055
	18	0.064	-	0.002	0.078	0.063	0.048	-	0.001	0.083	0.072
	19	0.055	-	0.001	0.060	0.047	0.048	-	0.001	0.093	0.081
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 19. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	0.046	-	0.001	0.107	0.098	0.030	-	0.001	0.048	0.042
	6	0.048	-	0.001	0.119	0.109	0.038	-	0.001	0.076	0.069
	7	0.049	-	0.001	0.096	0.085	0.040	-	0.001	0.074	0.066
	8	0.055	-	0.001	0.082	0.069	0.044	-	0.001	0.064	0.054
	9	0.055	-	0.001	0.077	0.065	0.043	-	0.001	0.063	0.054
	10	0.055	-	0.004	0.075	0.063	0.041	-	0.004	0.057	0.049
	11	0.055	-	0.051	0.073	0.061	0.038	-	0.049	0.052	0.044
	12	0.056	-	0.071	0.074	0.062	0.040	-	0.070	0.054	0.047
	13	0.056	-	0.088	0.073	0.061	0.041	-	0.086	0.057	0.049
	14	0.056	-	0.358	0.075	0.063	0.042	-	0.618	0.061	0.053
	15	0.057	0.458	0.609	0.179	0.064	0.043	0.700	0.163	0.063	0.053
	16	0.058	-	0.130	0.077	0.064	0.047	-	0.127	0.070	0.061
	17	0.059	-	0.121	0.071	0.057	0.055	-	1.095	0.202	0.071
	18	0.060	-	0.101	0.057	0.043	0.065	-	0.099	0.087	0.073
	19	0.060	-	0.058	0.054	0.040	0.069	-	0.057	0.084	0.069
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 20. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	0.044	-	0.001	0.092	0.082	0.036	-	0.001	0.071	0.065
	7	0.045	-	0.001	0.082	0.071	0.041	-	0.001	0.079	0.070
	8	0.058	-	0.002	0.080	0.065	0.049	-	0.001	0.076	0.065
	9	0.059	-	0.002	0.079	0.064	0.049	-	0.001	0.068	0.057
	10	0.058	-	0.002	0.080	0.066	0.042	-	0.001	0.055	0.045
	11	0.059	-	0.002	0.078	0.064	0.043	-	0.001	0.055	0.045
	12	0.058	-	0.002	0.077	0.063	0.043	-	0.001	0.057	0.047
	13	0.059	-	0.002	0.076	0.062	0.046	-	0.001	0.063	0.052
	14	0.059	-	0.002	0.077	0.063	0.047	-	0.001	0.068	0.057
	15	0.058	-	0.002	0.078	0.064	0.046	-	0.001	0.066	0.055
	16	0.059	-	0.002	0.078	0.063	0.051	-	0.001	0.080	0.068
	17	0.053	-	0.456	0.067	0.054	0.051	-	0.001	0.092	0.080
	18	0.053	-	0.001	0.051	0.039	0.051	-	0.001	0.093	0.082
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

Table 21. Average Hourly Seasonal Avoided Cost Values for Large Group Host Commercial Solar PV Array Installed in 2024 – Winter ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	-	-	-	-	-	-	-	-	-	-
	2	-	-	-	-	-	-	-	-	-	-
	3	-	-	-	-	-	-	-	-	-	-
	4	-	-	-	-	-	-	-	-	-	-
	5	-	-	-	-	-	-	-	-	-	-
	6	-	-	-	-	-	-	-	-	-	-
	7	-	-	-	-	-	-	-	-	-	-
	8	0.123	-	0.003	0.101	0.070	0.085	-	0.002	0.087	0.067
	9	0.121	-	0.003	0.099	0.069	0.085	-	0.002	0.084	0.064
	10	0.119	-	0.003	0.094	0.066	0.070	-	0.002	0.064	0.047
	11	0.118	-	0.003	0.091	0.064	0.066	-	0.002	0.057	0.041
	12	0.117	-	0.003	0.091	0.063	0.066	-	0.002	0.059	0.043
	13	0.117	-	0.003	0.092	0.064	0.065	-	0.002	0.058	0.042
	14	0.118	-	0.003	0.093	0.064	0.067	-	0.002	0.061	0.045
	15	0.118	-	0.003	0.094	0.065	0.071	-	0.002	0.064	0.046
	16	0.121	-	0.003	0.099	0.068	0.083	-	0.002	0.081	0.059
	17	0.126	-	0.003	0.099	0.068	0.094	-	0.003	0.097	0.075
	18	-	-	-	-	-	-	-	-	-	-
	19	-	-	-	-	-	-	-	-	-	-
	20	-	-	-	-	-	-	-	-	-	-
	21	-	-	-	-	-	-	-	-	-	-
	22	-	-	-	-	-	-	-	-	-	-
	23	-	-	-	-	-	-	-	-	-	-
	24	-	-	-	-	-	-	-	-	-	-

D.5 Micro Hydro

Table 22. Average Annual Avoided Cost Value for Micro Hydro System ($/kWh) (2024$)

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Energy	0.076	0.075	0.072	0.052	0.051	0.051	0.051	0.052	0.052	0.051	0.051	0.053
Transmission Charges	0.042	0.045	0.048	0.051	0.055	0.058	0.062	0.066	0.072	0.077	0.082	0.088
Distribution Capacity	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.008	0.007	0.007	0.007
Capacity	0.004	0.004	0.004	0.005	0.005	0.005	0.006	0.006	0.006	0.006	0.007	0.006
Distribution Line Losses	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
RPS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transmission Line Losses	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Risk Premium	0.010	0.008	0.007	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005	0.005
Ancillary Services	0.003	0.003	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
DRIPE	0.007	0.007	0.007	0.006	0.007	0.007	0.007	0.007	0.007	0.007	0.007	0.007
Distribution OPEX	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Utility Admin	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Environmental Externality	0.060	0.061	0.060	0.055	0.053	0.054	0.048	0.050	0.052	0.050	0.052	0.053
Total – Excluding Environmental	0.154	0.154	0.152	0.133	0.135	0.139	0.143	0.148	0.154	0.159	0.164	0.171
Total – Including Environmental	0.214	0.215	0.212	0.187	0.188	0.193	0.191	0.198	0.205	0.209	0.216	0.225

Table 23. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Spring ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Spring	1	0.055	-	0.001	0.080	0.067	0.032	-	0.001	0.049	0.041
	2	0.053	-	0.001	0.080	0.068	0.032	-	0.001	0.048	0.040
	3	0.053	-	0.001	0.082	0.069	0.029	-	0.001	0.039	0.032
	4	0.052	-	0.001	0.082	0.070	0.029	-	0.001	0.036	0.029
	5	0.054	-	0.001	0.083	0.070	0.027	-	0.001	0.028	0.021
	6	0.055	-	0.001	0.086	0.074	0.028	-	0.001	0.031	0.024
	7	0.058	-	0.002	0.083	0.070	0.034	-	0.001	0.048	0.039
	8	0.063	-	0.002	0.064	0.050	0.034	-	0.001	0.041	0.033
	9	0.062	-	0.002	0.061	0.047	0.031	-	0.001	0.034	0.027
	10	0.058	-	0.002	0.055	0.043	0.025	-	0.001	0.022	0.016
	11	0.056	-	0.001	0.049	0.037	0.022	-	0.001	0.019	0.014
	12	0.056	-	0.001	0.052	0.040	0.023	-	0.001	0.023	0.018
	13	0.056	-	0.001	0.051	0.039	0.023	-	0.001	0.024	0.019
	14	0.056	-	0.220	0.052	0.040	0.023	-	0.001	0.024	0.018
	15	0.058	-	0.002	0.055	0.042	0.024	-	0.001	0.022	0.016
	16	0.060	-	0.002	0.063	0.049	0.029	-	0.001	0.032	0.024
	17	0.065	-	0.002	0.078	0.062	0.041	-	0.001	0.064	0.054
	18	0.068	-	0.002	0.081	0.065	0.050	-	0.001	0.082	0.071
	19	0.069	-	0.222	0.079	0.062	0.056	-	0.002	0.081	0.069
	20	0.069	-	0.002	0.075	0.059	0.057	-	0.441	0.083	0.070
	21	0.068	-	0.255	0.072	0.055	0.057	-	0.949	0.085	0.072
	22	0.067	-	0.002	0.077	0.061	0.053	-	0.001	0.089	0.077
	23	0.066	-	0.002	0.084	0.068	0.048	-	0.001	0.084	0.073
	24	0.057	-	0.002	0.084	0.070	0.041	-	0.001	0.073	0.064

Table 24. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Summer ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Summer	1	0.048	-	0.001	0.077	0.067	0.039	-	0.001	0.067	0.060
	2	0.048	-	0.001	0.083	0.074	0.037	-	0.001	0.064	0.057
	3	0.047	-	0.001	0.098	0.088	0.035	-	0.001	0.058	0.052
	4	0.047	-	0.001	0.103	0.093	0.035	-	0.001	0.059	0.053
	5	0.047	-	0.001	0.113	0.103	0.035	-	0.001	0.062	0.055
	6	0.047	-	0.001	0.112	0.102	0.033	-	0.001	0.059	0.053
	7	0.048	-	0.001	0.091	0.081	0.037	-	0.001	0.066	0.058
	8	0.054	-	0.001	0.080	0.068	0.040	-	0.001	0.057	0.049
	9	0.055	-	0.001	0.076	0.064	0.041	-	0.001	0.059	0.051
	10	0.055	-	0.004	0.074	0.062	0.038	-	0.003	0.053	0.046
	11	0.055	-	0.042	0.072	0.061	0.037	-	0.041	0.049	0.042
	12	0.055	-	0.059	0.073	0.061	0.038	-	0.058	0.052	0.045
	13	0.056	-	0.072	0.072	0.061	0.040	-	0.071	0.055	0.048
	14	0.056	-	0.354	0.074	0.062	0.041	-	0.622	0.059	0.052
	15	0.056	0.334	0.590	0.150	0.063	0.041	0.511	0.143	0.060	0.050
	16	0.057	-	0.116	0.076	0.063	0.045	-	0.114	0.068	0.058
	17	0.059	-	0.114	0.071	0.057	0.054	-	1.053	0.175	0.070
	18	0.060	-	0.090	0.058	0.044	0.063	-	0.089	0.086	0.073
	19	0.060	-	0.063	0.055	0.040	0.070	-	0.062	0.085	0.070
	20	0.059	-	0.014	0.060	0.046	0.067	-	0.015	0.087	0.073
	21	0.059	-	0.023	0.060	0.046	0.064	-	0.023	0.088	0.074
	22	0.058	-	0.010	0.071	0.056	0.059	-	0.010	0.090	0.077
	23	0.057	-	0.002	0.080	0.067	0.052	-	0.001	0.089	0.079
	24	0.049	-	0.001	0.079	0.069	0.043	-	0.001	0.080	0.072

Table 25. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Fall ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Fall	1	0.060	-	0.002	0.086	0.070	0.054	-	0.001	0.085	0.072
	2	0.058	-	0.002	0.096	0.080	0.053	-	0.001	0.085	0.072
	3	0.059	-	0.002	0.102	0.087	0.053	-	0.001	0.086	0.073
	4	0.058	-	0.002	0.106	0.091	0.052	-	0.001	0.087	0.075
	5	0.058	-	0.002	0.104	0.089	0.051	-	0.001	0.088	0.076
	6	0.056	-	0.002	0.085	0.070	0.050	-	0.001	0.083	0.071
	7	0.057	-	0.002	0.081	0.066	0.052	-	0.001	0.085	0.072
	8	0.064	-	0.002	0.082	0.065	0.056	-	0.002	0.082	0.068
	9	0.063	-	0.002	0.081	0.064	0.053	-	0.001	0.073	0.060
	10	0.062	-	0.002	0.082	0.066	0.047	-	0.001	0.062	0.050
	11	0.062	-	0.002	0.080	0.065	0.047	-	0.001	0.059	0.048
	12	0.062	-	0.002	0.079	0.063	0.047	-	0.001	0.063	0.051
	13	0.062	-	0.002	0.078	0.062	0.049	-	0.001	0.066	0.054
	14	0.063	-	0.002	0.079	0.063	0.051	-	0.001	0.071	0.059
	15	0.063	-	0.002	0.080	0.064	0.051	-	0.001	0.071	0.058
	16	0.062	-	0.002	0.080	0.063	0.055	-	0.002	0.082	0.069
	17	0.063	-	0.178	0.076	0.059	0.060	-	0.002	0.092	0.077
	18	0.065	-	0.302	0.060	0.043	0.062	-	0.002	0.089	0.074
	19	0.065	-	0.002	0.055	0.038	0.063	-	0.636	0.090	0.075
	20	0.064	-	0.239	0.060	0.043	0.062	-	0.858	0.092	0.076
	21	0.065	-	0.002	0.072	0.053	0.062	-	0.002	0.095	0.079
	22	0.066	-	0.002	0.082	0.064	0.062	-	0.002	0.096	0.079
	23	0.066	-	0.002	0.084	0.065	0.061	-	0.002	0.093	0.076
	24	0.060	-	0.002	0.083	0.067	0.056	-	0.002	0.090	0.076

Table 26. Average Hourly Seasonal Avoided Cost Values for Micro Hydro System – Winter ($/kWh) (2024$)

		2024					2035				
Season	Hour	Energy	Capacity	T&D	ROC	Envr.	Energy	Capacity	T&D	ROC	Envr.
Winter	1	0.111	-	0.003	0.095	0.067	0.078	-	0.002	0.083	0.064
	2	0.111	-	0.003	0.096	0.069	0.074	-	0.002	0.077	0.059
	3	0.111	-	0.003	0.097	0.070	0.071	-	0.002	0.072	0.054
	4	0.111	-	0.003	0.098	0.071	0.071	-	0.002	0.071	0.053
	5	0.111	-	0.003	0.098	0.071	0.070	-	0.002	0.068	0.050
	6	0.111	-	0.003	0.093	0.065	0.074	-	0.002	0.077	0.059
	7	0.112	-	0.003	0.092	0.063	0.083	-	0.002	0.089	0.069
	8	0.121	-	0.003	0.100	0.069	0.089	-	0.002	0.091	0.069
	9	0.120	-	0.003	0.098	0.068	0.086	-	0.002	0.086	0.065
	10	0.118	-	0.003	0.094	0.066	0.073	-	0.002	0.067	0.050
	11	0.117	-	0.003	0.092	0.064	0.068	-	0.002	0.060	0.044
	12	0.116	-	0.003	0.091	0.064	0.069	-	0.002	0.062	0.046
	13	0.116	-	0.003	0.092	0.064	0.068	-	0.002	0.061	0.045
	14	0.117	-	0.003	0.093	0.065	0.070	-	0.002	0.066	0.049
	15	0.117	-	0.003	0.094	0.065	0.073	-	0.002	0.067	0.049
	16	0.119	-	0.003	0.098	0.068	0.084	-	0.002	0.083	0.061
	17	0.122	-	0.003	0.097	0.066	0.100	-	0.003	0.101	0.076
	18	0.124	-	0.222	0.091	0.059	0.107	-	0.003	0.102	0.076
	19	0.124	-	0.460	0.091	0.059	0.108	-	1.438	0.104	0.078
	20	0.123	-	0.003	0.097	0.065	0.107	-	0.003	0.106	0.080
	21	0.123	-	0.003	0.101	0.070	0.105	-	0.003	0.108	0.082
	22	0.121	-	0.003	0.102	0.071	0.102	-	0.003	0.105	0.080
	23	0.120	-	0.003	0.102	0.070	0.097	-	0.003	0.101	0.076
	24	0.111	-	0.003	0.093	0.064	0.087	-	0.002	0.094	0.073

E. Stakeholder Questions and Response

E.1 Allocation of Distribution Avoided Costs

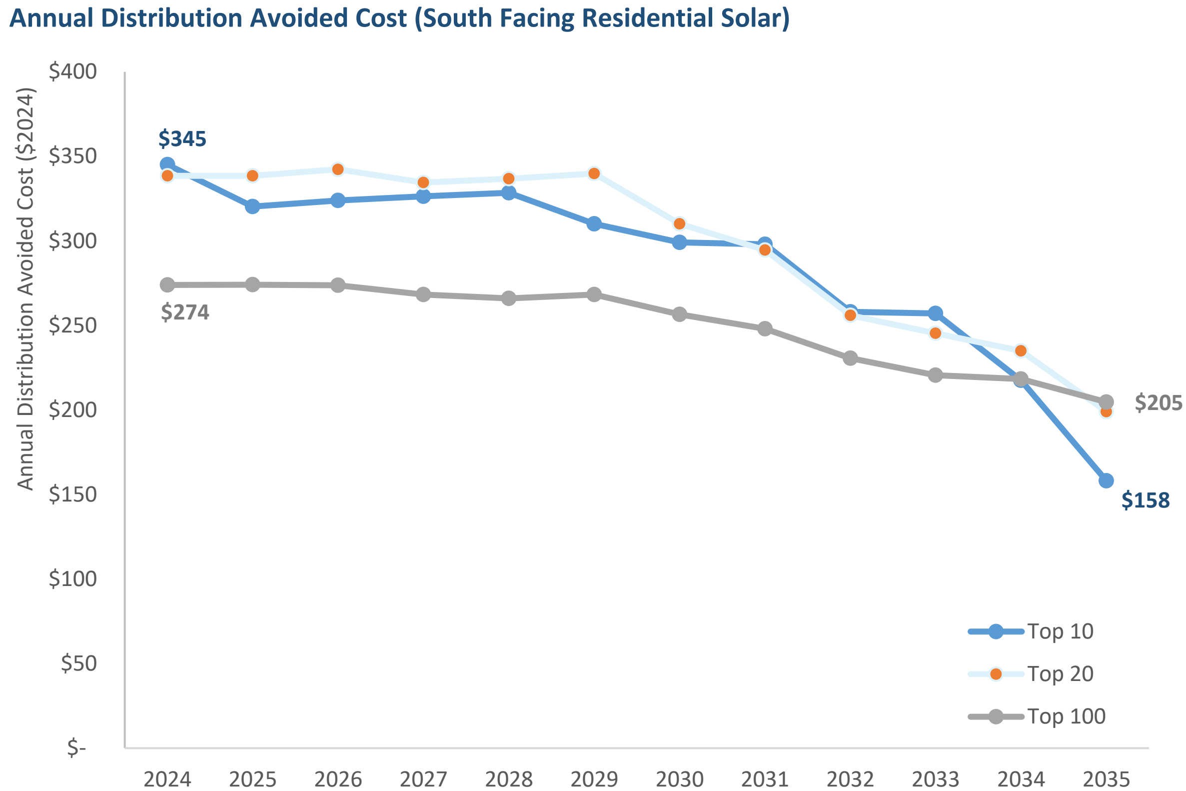
Stakeholder Question: Did Dunsky request hourly substation load data from the IOUs as an alternative to system load data? Dunsky could use a method such as the peak capacity allocation factor (PCAF) approach. This approach was used in The Alliance for Solar Choice (TASC) testimony DE 16-576. See Appendix D, pages D-6 to D-8 of the attached, for the details of that approach.

Dunsky Response:

- Dunsky did not request hourly substation load data from the IOUs as an alternative to system load data. As part of the VDER assessment, we focused on developing system-wide distribution avoided costs rather than substation-specific avoided costs. Distribution substations and circuits can peak at different times than the system, so we leveraged the LVDG study to estimate an average system-wide distribution avoided cost value.
- The approach laid out by TASC focuses on the avoided distribution costs from solar, and our goal was to develop tech-neutral avoided costs. However, we adopted a similar approach to the one described in DE 16-576 (Appendix D), wherein we proportionally allocated the distribution value across the top 100 hours. We recognize that it is challenging to predict the system peak hour; thus, by distributing the avoided distribution costs across the top 100 hours, we can approximate the avoided distribution costs from a DER.

The avoided Dist. Capacity and OPEX Costs ($/kW-year) are based on the LVDG study and utility data. However, the spread of the annual distribution avoided costs across specific hours in a given year will impact the value stack and the value captured by DG systems, as shown in the table below. The selection of the hours is based on the top load hours for the system.

Distribution Approach	Annual Distribution Avoided Cost $/kW-year ($2024)	Distribution Value Over Specific Hours ($/kWh) ($2024)	Key Characteristics
Top 10 Hours	$82 - $84	$8.2 - $8.4	In 2021, these hours occurred in Mid-August (HE 13 –17), and by 2035 the distribution hours could shift later into the evening (HE 14 –21).
Top 20 Hours	$82 - $84	$4.1 - $4.2	July-August (HE 13 –17), by 2035, shift later into the evening (HE 14 –21).
Top 100 Hours	$82 - $84	$0.82 - $0.84	Current Approach, all top 100 load hours occur in Summer.
Summer Top 20 Hours	$82 - $84	$4.1 - $4.2	Similar to the Top 20 hours.
Summer Targeted	$82 - $84	$0.82 - $0.84	Top 100 load hours occur in Summer.
Winter Top 20 Hours	$82 - $84	$4.1 - $4.2	Jan-Dec (HE 18-19), by 2035, shift later into the night (HE 19 – 20).
Winter Targeted	$82 - $84	-	None of the Top 100 load hours occur in Winter



In the VDER study, the distribution avoided costs were spread over the top 100 load hours in the year. Under this valuation method, the annual distribution value that a typical residential PV system can capture is about $234.

Spreading the distribution costs over fewer hours could lead to an increased distribution value for residential solar in the initial part of the study period. For example, reducing the number of distribution hours to 10 approximates a 25% increase in distribution value in 2024.

However, the distribution peak shift into the evening could decrease the distribution value across the study period. In 2035, the distribution value under the top 10 hours is about 23% lower than the current assumption of 100 hours. Therefore, spreading the distribution value over more hours (~100) results in greater certainty of annual distribution avoided cost, albeit at a lower value.

E.2 Treatment of Settlement-Only Generators

Stakeholder Question: Are capacity and energy revenues received by the utilities properly accounted for and deducted for any claimed “costs” of net metering, and was this revenue from small hydro group hosts considered and accounted for in the VDER study?

Dunsky Response:
As a part of the RBI assessment, Dunsky evaluated the incremental impact of customer-sited solar for residential, commercial, and large commercial customers on retail rates. In New Hampshire, customer-sited solar greater than 100 kW could enter the ISO-NE market as settlement-only generators (SOGs) and receive energy and capacity payments for the excess energy (not consumed behind the meter) exported to the grid. As of April, there were 20 net metered SOGs (3 Hydro, 17 Solar) with a maximum capacity of 10.9 MW (1.9 MW Hydro, 9.0 MW Solar).

Energy: When net-metered small-scale solar facilities generate energy, the utility receives wholesale energy revenue for that generation. However, the avoided energy is simply a pass-through component, meaning that it doesn't have any impact on rates. Even though the utility is compensated at the wholesale market, the lost revenue from energy generated by the DG will be equal to the avoided costs. This means that the SOG payment wouldn't affect rates, specifically this portion of it.

Capacity: The utility receives capacity payments for net metered SOGs, but the capacity payments are limited. Only a few net-metered Hydro facilities have Forward Capacity Auction (FCA) obligations and receive monthly payments. Most SOGs without FCA obligations only receive payments under the Pay-For-Performance structure for generation during scarcity events. Avoided capacity is not considered a passthrough component (in line with the Synapse NH RBI Energy Efficiency assessment); thus can impact rates. The current RBI assessment assumes that a utility's fixed cost for generation is the sum of avoided costs from Capacity and DRIPE. If the utility receives capacity payments, the fixed cost for generation should decrease, thereby reducing the upward impact on rates. However, few systems are bid into the ISO-NE as SOGs, so the impact should be minimal.

The RBI assessment assumes that the pre-DG rates include the impact of existing small hydro facilities and that no new facilities come online. Large group host community solar could impact the rates; however, the assessment excluded these assets from the analysis given the challenges associated with developing a robust market adoption of community solar.

Guidehouse

New Hampshire Locational Value of Distributed Generation Study

Final Report

Prepared for:

New Hampshire Public Utilities Commission

Submitted by:

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77 South Bedford Street | Suite 400 | Burlington, MA 01803

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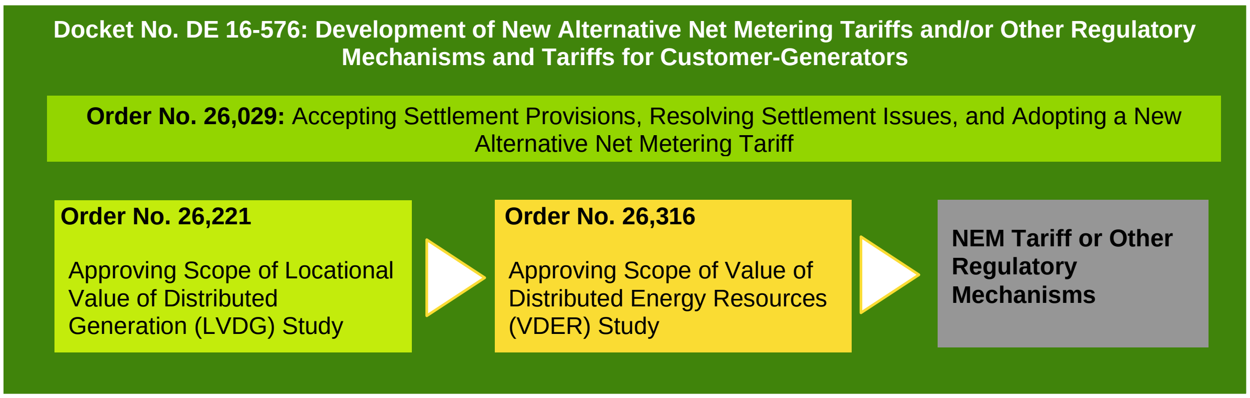
Executive Summary

The New Hampshire Public Utilities Commission (the Commission) engaged Guidehouse to conduct a Locational Value of Distributed Generation (LVDG) study for electric distribution companies (EDCs) under its jurisdiction. The LVDG study falls under the Commission's ongoing net metering docket. In its February 2019 order,[1] the Commission approved the LVDG study scope and authorized the study to inform the development of future net energy metering (NEM) tariffs or other regulatory mechanisms in the state. This report presents the LVDG study methodology, parameters, assumptions, analysis, results, and conclusions.



Source: New Hampshire Public Utilities Commission

The study evaluates the distribution-level locational value of load reductions potentially achievable by distributed generation (DG) for New Hampshire's three regulated EDCs: Public Service Company of New Hampshire d/b/a Eversource Energy, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities, and Unitil Energy Systems, Inc. The LVDG study analysis identifies and quantifies technology-neutral load reduction opportunities for each of the three regulated EDCs, relying heavily on data and information provided by the EDCs. Several meetings were held with LVDG stakeholders, the EDCs, and Commission Staff to review results as the study proceeded.

The study covers a timeframe of 5-years' historical, and 10-years' forward-looking, beginning in year 2020. Distribution system capacity constraints are analyzed under base, low, and high load growth scenarios. The study focuses on significant distribution system capacity deficiencies to be addressed through planned or potential capital investments, such as replacements or upgrades of substations or circuits. No minimum investment threshold level for the cost of upgrades is required for a location to be evaluated; however, small capital investments such as pole top distribution transformers and capacitors will be included in an upcoming separate system-wide Value of Distributed Energy Resources (VDER) study and are not covered in the LVDG study.

[1] NHPUC Docket No. DE 16-576, Order Approving Scope of Locational Value of Distributed Generation Study, Order No. 26,221 (February 20, 2019).

When evaluating load reductions to avoid capital investments, the study considers three specific NEM-eligible DG technologies: solar photovoltaic (PV), solar PV paired with energy storage, and hydroelectric generation, all with capacities rated up to one megawatt (MW).

The study methodology includes three steps:

- **Step 1:** Location Identification – Identify potential locations with expected capacity constraints requiring investments over the study timeframe, including base, low, and high load growth sensitivity analysis.
- **Step 2:** Estimation of Investment Costs for Avoidance – Determine the value of potential avoided capacity investments at the selected locations.
- **Step 3:** Economic Analysis and Mapping of DG Production Profiles with Distribution Capacity Needs – Perform economic analysis to estimate the benefit of capacity avoidance and map representative DG production profiles with distribution system capacity needs.

The Step 1 analysis reviews 696 locations and identifies 122 locations on the EDC distribution systems (i.e., circuits and substations) with capacity deficiencies, where capital investments potentially could be avoided through load reduction attributable to NEM-eligible DG. It should be noted that a transformer may have been reviewed at both the substation and circuit level, so the total locations reviewed may not equal the total quantity of equipment on an EDC's distribution system.

The study uses three load forecasts, base, low, and high, for each of the EDCs to complete a sensitivity analysis of the capacity deficiencies identified. The primary load growth forecast refers to what was developed and used by each EDC to identify planning criteria violations, referred to as the Base Case. The base, low, and high load growth forecasts varied among the three EDCs. Under the Base Case load growth scenario, 45 actual or potential capacity deficient locations were identified; 77 additional locations were identified under the high load growth scenario. Under the low load growth scenario, 26 locations would have capacity deficiencies during the study timeframe.

From the 122 locations identified, a subset was selected for detailed analysis. The subset of locations includes:

- Locations from each EDC's service territory and regions
- Future and historical projects, including circuits, and bulk and non-bulk substations
- Winter and summer peaking locations
- Midday and late-day peaking locations
- Locations with identified capacity deficiencies under various load growth forecasts
- Locations with small and large capacity deficiencies
- Locations with normal and contingency overloads or performance violations

- Locations where data was available to comprehensively analyze each site to determine the cost of traditional capacity solutions

The subset of locations selected for detailed analysis are listed in the table below.

EDC	Description	Region	Type of Investment	Load Growth Forecast Scenario	Historical or Future	First Year of Capacity Deficiency[2]
Eversource	Pemigewassett (Pemi)	Northern	Substation (Bulk)	Base	Future	2020
	Portsmouth	Eastern	Substation (Bulk)	Base	Future	2020
	South Milford	Southern	Substation (Bulk)	Base	Future	2020
	Monadnock	Western	Substation (Bulk)	Base	Future	2020
	East Northwood	Eastern	Substation (Non-Bulk)	High	Future	2021
	Rye	Eastern	Substation (Non-Bulk)	High	Future	2022
	Bristol	Northern	Substation (Non-Bulk)	Base	Historical	2015
	Madbury ROW	Eastern	Circuit (34.5 kV)	Base	Future	2020
	North Keene	Northern	Circuit (12.47 kV)	High	Future	2028
	Londonderry	Southern	Circuit (34.5 kV)	Base	Historical	prior to 2014
Liberty	Vilas Bridge	Walpole	Substation (Non-Bulk)	Base	Future	2020
	Mount Support	Lebanon	Substation (Bulk)	Base	Historical	2014
	Golden Rock	Salem	Substation (Bulk)	Base	Historical	2019
Unitil	Bow Bog	Capital	Substation (Non-Bulk)	High	Future	2024
	Dow's Hill	Seacoast	Substation (Bulk)	High	Future	2020
	Kingston	Seacoast	Substation (Bulk)	Base	Historical	prior to 2014

For each location, comprehensive data was analyzed to determine cost estimates for traditional utility investments designed to meet specific locational capacity needs. For each historical distribution capacity project, the study applies the assumptions, including EDC planning criteria that existed at the time the project was initially proposed or placed into service, to determine utility investment costs that might have been avoided. It should be noted that a number of the forward-looking locational capacity deficiencies and related investment costs are driven by a recent change in Eversource's system planning criteria.

Location	Year Considered	Revenue Requirement	Total Hours of Capacity Deficiency	Total Annual MWh of Capacity Deficiency	Maximum $/kW/hr	Relative $/kW/hr Value Ranking
Pemi Substation (Bulk)	2020	$9,074,650	326	509	$2.45	11
Portsmouth Substation (Bulk)	2020	$3,037,438	1,966	7,446	$0.04	16
South Milford Substation (Bulk)	2020	$15,976,924	6,696	41,928	$0.05	14
Monadnock Substation (Bulk)	2020	$17,374,146	15	10.53	$203.68	6
East Northwood Substation (Non-Bulk)	2021	$242,995	3	0.07	$256.77	5
Rye Substation (Non-Bulk)	2022	$3,644,926	2	0.10	$3,185.54	2
Bristol Substation (Non-Bulk)	2020	$1,457,970	5	0.43	$301.37	4
Madbury ROW Circuit (34.5 kV)	2020	$2,429,950	7	14	$17.03	8
North Keene Circuit (12.47 kV)	2028	$1,858,912	1	0.11	$1,128.25	3
Londonderry Circuit (34.5 kV)	2020	$747,210	467	115.81	$1.01	13
Vilas Bridge Substation (Non-Bulk)	2020	$2,715,803	909	247.68	$2.91	10
Mount Support Substation (Bulk)	2020	$7,557,017	1,329	21,484	$0.04	15
Golden Rock Substation (Bulk)	2020	$8,983,404	164	434	$3.14	9
Bow Bog Substation (Non-Bulk)	2026	$299,375	5	0.27	$128.17	7
Dow's Hill Substation (Bulk)	2022	$525,674	2	0.008	$4,483.12	1
Kingston Substation (Bulk)	2020	$14,371,184	203	789	$2.00	12

The study analyzes the potential value of capacity deficiency avoidance resulting from load reduction, including the time-differentiated value of avoiding traditional capacity investments on an hourly basis, using the Real Economic Carrying Charges (RECC) methodology. The RECC method creates a stream of annual values over the lifetime of an investment by calculating the total and annual revenue requirements. The revenue requirement in the first year the investment is needed increases annually at a fixed rate of inflation.

The time-differentiated revenue requirement is determined by spreading the first-year revenue requirement across the hours of locational capacity deficiency using a weighted average approach. Those hourly capacity avoidance values are determined on a technology-neutral basis, based on locational load reduction.

The study also evaluates the alignment of DG production profiles with capacity deficiency profiles for the three NEM-eligible DG technologies. For solar PV, the study develops a 24-hour average solar PV production profile using the National Renewable Energy Laboratory's (NREL) PVWatts Calculator and data. Solar paired with energy storage assumes the system stores excess energy during hours of production and discharges the energy during non-production hours of deficiency. The production profile for hydro represents a run-of-river hydro unit and is based on historical generation data.

The LVDG study findings and conclusions are summarized below:

- Out of 696 total potential locations, 122 distribution system substations or lines were identified as candidate locations for detailed analysis of capacity investment avoidance opportunities under base, low, and high load growth forecast scenarios. Of the 122 locations considered, 13 are historical and 109 are future, with 77 triggered only in the High Case during the study time horizon.
- The projected capacity deficiencies for the three EDCs beginning in 2020 total approximately 107 MW, increasing to 147 MW by 2029, under the base load forecast. Total capacity deficiencies in 2029 for the low load growth forecast are 63 MW and for the high load growth forecast are 317 MW. A substantial number of capacity deficiencies occur in 2020, the first year of the forward-looking period covered by the study, in large part due to recent changes in planning criteria implemented by Eversource.
- Of the 16 locations selected for detailed analysis, five are historical investments. Five of the 16 locations have first year capacity deficiencies that occur during both winter and summer months; the remaining 11 are summer peaking only.
- The cost of traditional distribution system investments to address capacity deficiencies at the selected locations, expressed in terms of a revenue requirement, ranges from less than $1 million to over $14 million. The total value of traditional capacity investments at the 16 selected locations is approximately $75 million.

- The economic value of capacity investment avoidance varies significantly among the 16 locations based on a theoretical analysis of capacity avoidance using the RECC approach. The maximum hourly economic value of capacity investment avoidance ranges from under $1 per kilowatt (kW) per hour to over $4,000 per kW per hour. The greatest driver for that variance is the total number of hours over which capacity deficiencies occur at a specific location. The lower value is generally indicative of a capacity deficiency that occurs over a large number of hours, while the higher value is generally indicative of a capacity deficiency that occurs during fewer hours.
- Related findings from the capacity deficiency analysis and evaluation of DG production profiles are summarized as follows:
    - The number of hours of capacity deficiency varies significantly by location, with some locations with fewer than 15 hours of deficiency per year, while other locations are capacity deficient for several thousand hours per year.
    - Most locations have capacity deficiencies during late afternoon or early evening hours. Solar PV production profiles do not fully align with those hours of capacity deficiency. Solar PV paired with energy storage typically can produce electricity during most or all hours during which there are locational capacity deficiencies.
    - Hydro production profiles typically align with hours of capacity deficiency, but with lower production during summer months as compared to winter months.

The study does not attempt to identify a specific solution or set of DG technologies that would meet the capacity needs at any selected location, nor to estimate the actual capacity of each DG technology that might be required at a given location to meet the specific capacity need. In this sense, the study does not attempt to perform a non-wires solution (NWS) analysis to meet the identified locational capacity need.

Potential avoided distribution system capacity costs related to power quality and lower distribution elements, such as distribution transformers and capacitors, will be considered on a system-wide level within the VDER study, and are not considered in this study. The LVDG study is not intended to determine a system-wide value of DG, but the results of this study are expected to be used in the VDER study.

The LVDG study results are not intended to predetermine future NEM tariff design or applicable rates, but rather to inform further NEM tariff development proceedings before the Commission. The study results and identification of locations and costs of potential avoided capacity investments may be relevant in a number of other contexts before the Commission, such as grid modernization, future utility rate cases, and future least cost integrated resource plans.

1.0 Introduction

The New Hampshire Public Utilities Commission (the Commission) engaged Guidehouse to conduct a Locational Value of Distributed Generation (LVDG) study for electric distribution utilities under its jurisdiction. The LVDG study falls under the Commission's ongoing net metering docket and its February 2019 order approving the LVDG study scope and authorizing the study, which (in conjunction with other studies and pilots) will inform the development of future net metering tariffs or other regulatory mechanisms in the state.[2] This report presents the LVDG study methodology, analysis details, results, and conclusions.

The required electrical capacity to reliably serve customer loads (i.e., capacity need) has historically been met using traditional utility transmission and distribution (T&D) investments (e.g., substations, circuits, poles, wires, transformers, etc.). Those traditional investments are determined using approved electric distribution company (EDC) system T&D planning criteria.

The LVDG study is based on a series of analytical steps to evaluate and estimate the locational value of potentially avoidable distribution system capacity upgrades at various locations. These analytical steps use the EDCs' planning criteria as well as their approaches to estimation of the costs of providing a traditional solution to meet identified capacity needs.

The LVDG study considers three DG technologies—solar photovoltaic (PV), solar PV paired with energy storage, and small hydroelectric (hydro)—each of which is eligible under the EDCs' net energy metering (NEM) tariffs. The study analyzes distribution capacity needs over a 10-year future planning horizon, and over a 5-year historical period, at locations across the state to develop a locational list of capacity needs. The study includes sensitivity analyses that consider low and high scenarios for load growth, incorporating a number of variables. A subset of locations was selected for detailed analysis. For the subset, cost estimates for traditional utility investments to meet locational capacity needs were determined.

The study analyzes the potential value of capacity deficiency avoidance resulting from load reduction. Avoided costs at each location are then distributed across the years of capacity need within the planning horizon and allocated to the annual hours of capacity need based on hourly load deficiency analysis. The hourly capacity avoidance values represent a technology neutral value for meeting distribution capacity deficiencies during each hour of need. Lastly, DG production profiles for the three specific NEM-eligible technologies are developed and used to illustrate the coincidence of DG hourly production with hours of locational capacity need.

The study does not attempt to identify a specific solution or set of DG technologies that would meet the capacity needs at the selected locations, nor to estimate the actual

[2] NHPUC Docket No. DE-16-576, Order Approving Scope of Locational Value of Distributed Generation Study, Order No. 26,221 (February 20, 2019).

capacity of each DG technology that might be required at a given location to meet the specific need. In this sense, the study does not attempt to perform a non-wires solution (NWS) analysis to meet the identified locational capacity needs.

The Introduction subsections,1.1 through 1.6:

- Present the objectives of the study within the regulatory context
- Illustrate the analysis timeframe used for the study
- List the EDCs within New Hampshire and data and related information used in the study
- Describe the DG technology reviewed
- Provide an overview of the study approach and report structure

The subsequent sections of the report present the analytical steps used to perform the LVDG analysis, and results and conclusions.

1.1 Regulatory Context

The Commission engaged Guidehouse to conduct the LVDG study with respect to the electric distribution systems owned and operated by the three EDCs under its jurisdiction. The purpose and subsequent authorization of the LVDG study is outlined in the Commission's orders issued in its ongoing net metering docket.[3]

In its June 2017 order,[4] the Commission required actions be taken to collect data and develop a comprehensive record to inform future net metering tariff modifications or alternative compensation mechanisms. That order also required the Commission to undertake a Value of Distributed Energy Resources (VDER) study. The objective of the VDER study is to fulfill Order No. 26,316,[5] which approved the scope and timeline of a study of the system-wide value of distributed energy resources in New Hampshire. The results of the VDER study are intended to inform further action in the net metering docket, as well as having potential relevance in other contexts such as matters involving distributed generation integration, utility system planning, and grid modernization.

[3] NHPUC Docket No. DE-16-576, Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576.html

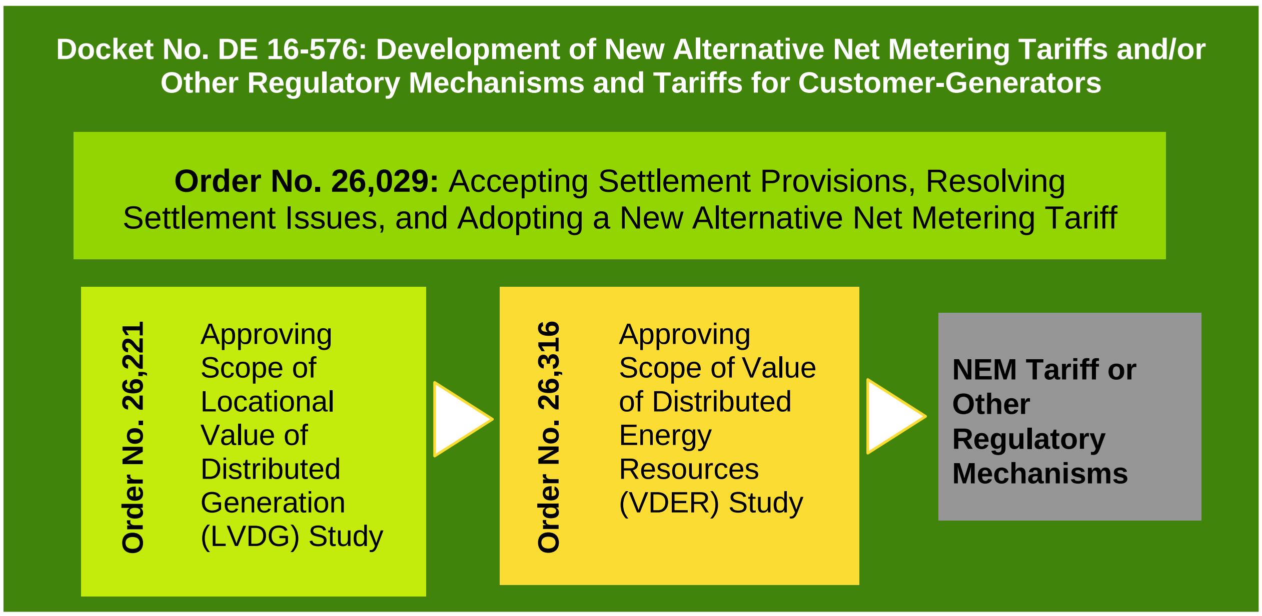
[4] NHPUC Order No. 26,029, Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff, June 23, 2017. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF (approving the adoption of a new alternative net energy metering tariff, designed to be in effect for a period of years while additional data is collected and analyzed, pilot programs are implemented, and a value of distributed energy resource study (VDER Study) is conducted.)

[5] NHPUC Order No. 26,316, Approving Scope of Value of Distributed Energy Resources, December 18, 2019. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2016/16-576/ORDERS/16-576_2019-12-18_ORDER_26316.PDF

In April 2018, the Commission directed its staff and stakeholders to focus on studying the locational value of distributed generation rather than developing NWS pilots.[6] The objective of the LVDG study is to fulfill Order No. 26,221,[7] which approved the scope and timeline of a study of the locational value of DG in New Hampshire.

The LVDG study results will be available for consideration as inputs to the VDER study. Both studies will inform future net energy metering tariffs and alternative compensation mechanisms. However, dollar value results of the LVDG study cannot be directly applied to a compensation mechanism. Results of the LVDG study may also be useful for consideration in the Least Cost Integrated Resource Plan dockets and in the Grid Modernization docket.[8]

Figure 1. Regulatory Context



Source: New Hampshire Public Utilities Commission

Stakeholder review and input were solicited as part of the LVDG study process through three public stakeholder workshops, which presented analysis updates throughout the

[6] NHPUC Order No. 26,124, Order Addressing Non-Wire Alternative Pilot Program, April 30, 2019. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2018-04-30_ORDER_26124.PDF

[7] NHPUC Order No. 26,221, Approving Scope of Locational Value of Distributed Generation Study, February 20, 2019. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2019-02-20_ORDER_26221.PDF

[8] NHPUC Docket No. IR 15-296, Investigation into Grid Modernization. Order No. 26,358. (May 22, 2020)(Stating "There will likely be synergies between the Commission's ongoing Locational Value of Distributed Generation Study and the locational value analysis that will take place as part of the LCIRP process. We anticipate that the deliverables associated with step one (net load forecasting and equipment criteria violation identification) and step two (identify cost of traditional solution) of the Locational Value of Distributed Generation Study may inform the analysis occurring in each utility's LCIRP, and in some cases, future annual updates." https://www.puc.nh.gov/Regulatory/Docketbk/2015/15-296/ORDERS/15-296_2020-05-22_ORDER_26358.PDF

study period. Each workshop was attended by EDC representatives, other parties in the NEM proceeding, and interested stakeholders. During those three workshops, questions and feedback from attendees were addressed.

1.2 Study Scope and Analysis Parameters

The LVDG study parameters and methodology address the Commission-approved Locational Value of Distributed Generation Study scope, which includes the following elements:

Relationship to VDER: The LVDG study has been conducted as a separate analysis from the VDER study. Findings from the LVDG study will be used in conjunction with the VDER study to inform future NEM tariff development and DG compensation proceedings.

Technologies Considered: The study focuses on DG that is eligible for NEM and interconnected to a New Hampshire EDC, including solar PV, solar PV paired with energy storage, and hydroelectric.

Eligible Avoided Costs: The study considers the value of avoided distribution investment costs due to capacity constraint elimination through load reduction at a number of locations on the New Hampshire electrical distribution grid. Potential avoided or deferred distribution system costs related to power quality and lower distribution elements, including distribution transformers and capacitor banks, were not considered. All investment costs are based on actual EDC expenditures for the capacity-related component of historical projects. For forward-looking locations, EDC budget estimates were used. For forward-looking locations where budget data is not available, EDC unit cost data was applied to estimate project costs. A subset of locations was selected for detailed study of potentially avoidable distribution investments. The detailed study provides an indicative set of potential avoided cost values; however, the results are not extrapolated to all locations with violations or deficiencies across the state. Accordingly, the LVDG study is not intended to determine a system-wide value for DG, as those system-wide, lower order distribution investment deferrals will be considered within the distribution components of the VDER study.

Timeframe: The study examines avoided investment costs over a fifteen-year timeframe. The study baseline reviews the past 5 years of load and investment data to establish historical expenditures. The final agreed-upon study includes the optional study period extension of a further 5-year projection, extending the future study horizon to 10 years. Thus, a 15-year study period was used: 5 years of historical analysis and 10 years of future analysis.

Geographic Scope: The geography includes the distribution systems of the three regulated EDCs in New Hampshire.

Distribution System Analysis Level: The analysis covered the distribution systems of the three EDCs. For the purposes of this study, this is defined as: Sub-transmission (13 kV-69 kV), Substation, and Distribution Circuits.[9]

Load Growth Projections: Baseline analysis was performed using load growth projections developed by each utility for its planning processes. However, in all cases regardless of utility practice, the load growth projection uses a counterfactual Base Case analysis that excluded future projections of historically observed growth in net-metered DG investment. The study incorporates both a high load growth scenario and low load growth scenario to define sensitivity parameters around the Base Case analysis. The low load growth scenario includes assumptions about increased levels of energy efficiency and conservation and other assumptions about average weather conditions. The high load growth scenario includes assumptions regarding aggressive electric vehicle adoption, low levels of energy efficiency and conservation, and other assumptions about extreme weather conditions.

Investment Threshold: The analysis focuses on significant distribution system capacity needs and planned or potential investments and excludes small program investments that are part of a system benefit initiative, such as pole top distribution transformers and capacitors. Those small program investments may be included in the separate system-wide VDER analysis.

Locations for Review: Projects considered for detailed review include locations with capacity constraints identified in the EDC's 5-year historical spending reports and investments included in forward-looking capital investment plans. Projects considered also included those identified through a 10-year forward-looking capacity deficiency analysis. These projects include those:

- Identified through forward-looking load growth projections and screening using utility normal (N-0) planning criteria.
- Identified as capacity-related investments through review of 5-year historical spending and planning materials such as EDC budgets and capacity planning studies.
- Identified as contingency (N-1) investments.[10]
- With non-load growth-related investment needs (e.g., asset management) that also include a capacity component. Where both load and non-load investments are

[9] Although the study evaluates the value of avoiding distribution system investments for lines and substations rated 34.5kV and below, the analysis includes the impact of avoiding these investments on sub-transmission assets rated up to 69kV.
[10] Contingency investments are those that are needed to address capacity deficiencies that occur when a single component fails or is out of service, causing overloads on the other equipment. A common example is a substation equipped with two transformers, where a loss of one of the two transformers will cause the remaining in-service transformer to become overloaded.

made for the same project, only incremental investment costs caused by capacity increases are considered.

A selection of these analysis parameters are expanded upon in the subsections that follow, in which additional detail is provided to facilitate understanding of the analysis steps presented in later sections.

1.3 Analysis Timeframe

Figure 2 illustrates the study analysis timeframe. The analysis looks ahead 10 years into the future, and also looks back at 5 years of historical data, thus using a 15-year study timeframe overall.

Figure 2. LVDG Analysis Timeframe

Source: Guidehouse

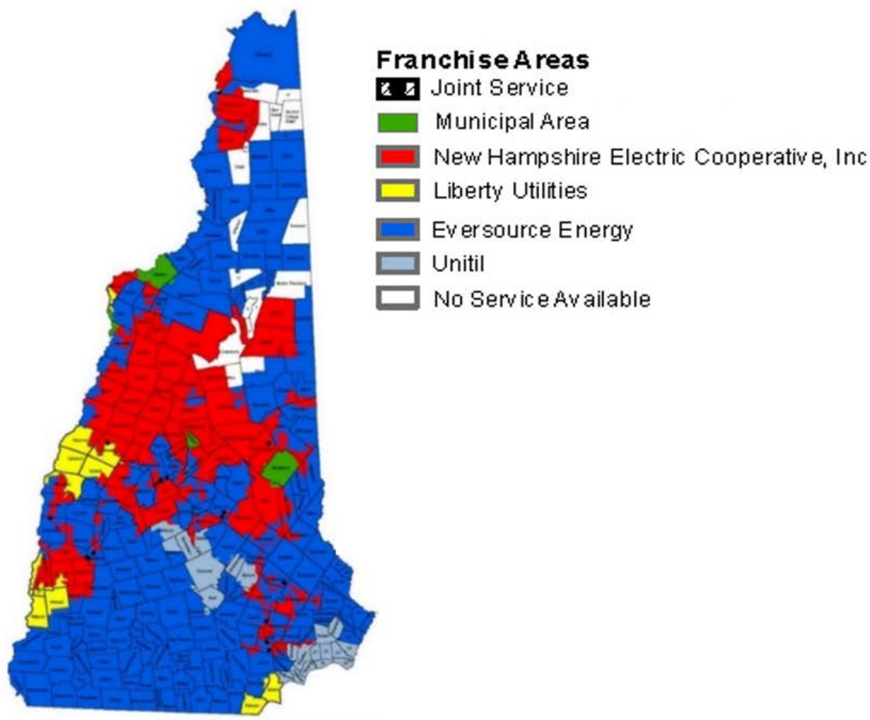
For locational analysis of various EDC distribution system capacity upgrade projects that were examined, two distribution planning assumptions that existed at the time the project was initially proposed or placed into service were applied. First, load forecasts for future projects are based on current load growth projections, whereas for historical projects, the load growth projections originally used by the EDC to justify the project were applied. Second, the capacity planning criteria applied to evaluate historical projects is based on documented planning criteria at the time the project was originally proposed.[11]

[11] Note that smaller, *normal course* distribution investments are excluded from the analysis, as they are included in the approved scope of the separate VDER study. The VDER study scope provides that potential avoided distribution costs related to power quality and lower distribution elements, including distribution transformers and capacitor banks, will be considered on a systemwide level. Accordingly, those potential avoided costs are not considered in this LVDG study, as it is not intended to determine a systemwide value for DG.

1.4 Electric Distribution Companies

The study evaluates the locational value of DG for the three regulated EDCs in New Hampshire: Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource), Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (Liberty), and Unitil Energy Systems, Inc. (Unitil). The study excludes publicly owned utilities such as electric cooperatives and municipally owned systems.[12] Those three EDCs serve retail customers throughout the state, including most of the larger towns and cities. Figure 3 displays the service territories of each of the three EDCs. It is within those areas that historical and future distribution capacity deficiencies are identified. The study assesses the value of avoided distribution capacity investments at the selected locations within those EDC service territories. [13]

Figure 3. EDC Franchise Service Territories



Source: New Hampshire Public Utilities Commission, [State of New Hampshire Electric Utility Franchise]()

Table 1 presents the number of electric customers and sales by EDC. Eversource serves the greatest number of customers in New Hampshire (over 80% of the state's total customers served) across all regions of the state, whereas Liberty's service territory is located in the western and southern sections of the state, and Unitil primarily serves the seacoast and capital areas. In later sections, regions within each EDC's

[12] The impact of publicly-owned utilities served by lines owned by the EDCs is considered, where applicable.
[13] Throughout the study, a traditional investment is considered "avoided" if the need for the investment is eliminated due to load reduction within the study timeframe.

service territory are assessed to identify distribution capacity avoidance opportunities on a locational basis.

Table 1. EDC Statistics

EDC	Number of Electric Customers	2019 Peak Demand (MW)	2019 Energy Sales (GWh)
Eversource	534,000	1,639	7,681
Liberty	44,517	188	0.899
Unitil	78,223	240	1.154

Source: Eversource, Liberty, Unitil

In New Hampshire, the electric distribution system delivers electric service at voltages of 34.5 kV and below.[14] For purposes of the study, locational capacity investments are defined as lines, circuits, and/or substations that are used to deliver electricity to retail customers.[15]

1.5 Distributed Generation Technologies

The study evaluates specific NEM-eligible technologies: solar PV, solar PV paired with energy storage, and hydroelectric. As of April 2020, approximately 112 MW of DG was interconnected and eligible for net metering in the EDC service territories. Technologies currently interconnected include solar, wind, hydroelectric, and residential solar with storage.

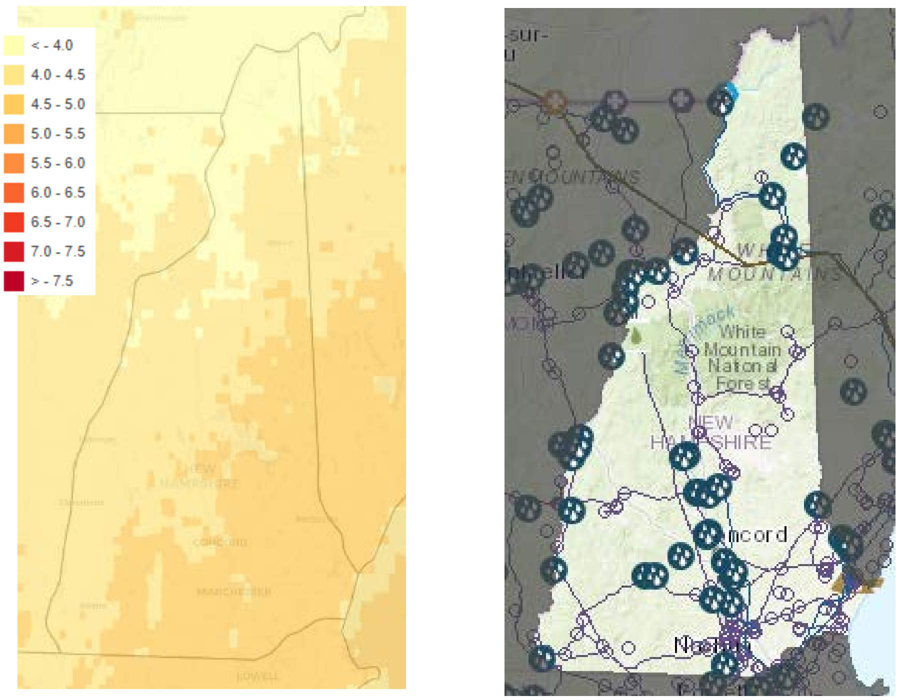
Figure 4 presents solar energy potential and the existing hydroelectric sites across New Hampshire.[16] Although specific locations of all existing or proposed solar PV installations are not shown on the map, solar potential exists across the state while NEM-eligible hydro is limited to streams and rivers suitable for project development.[17,18]

As of 2019, there were a total of 88 conventional hydroelectric generation facilities operating in New Hampshire and reporting to the Energy Information Administration (EIA) as part of Form EIA-860 on an annual basis. Those hydroelectric generation facilities include NEM-eligible and non-NEM-eligible facilities that are too large to qualify for net metering. Of the 88 facilities, 37 of them, representing close to 4% of the total

[14] The term “lines” refers to distribution circuits operating at voltages 34.5kV and below. The terms “circuit” and “feeders” have the same meaning and are used interchangeably throughout this report.
[15] Although the study limits distribution facilities to those rated 34.5kV and below, some investments may include equipment rated to operate at higher voltages, such as distribution substation power transformers rated 115/34.5kV, and new 115kV lines that are needed to deliver power and energy to those substations. Further, some lines rated 34.5kV serve a dual function of supplying lower voltage substations and delivering power and energy to retail customers. Lines that provide dual functionality often are referred to as right-of-way (ROW) lines. Most of the ROW lines are owned and operated by Eversource.
[16] Note: it is understood that solar and other DG developers pay costs associated with installation and interconnection; these costs are not considered in the LVDG study but will be evaluated as relevant to system-wide values in the VDER study.
[17] The study did not assess where NEM-eligible hydroelectric generation is suitable from a hydrological or permitting perspective, but recognizes that some locations may be suitable and other locations may encounter constraints and barriers that restrict or prohibit any potential hydroelectric development.
[18] Note that the amount of solar PV capacity that can be installed at a particular utility location is subject to “hosting capacity” limits and other interconnection policies. Hosting capacity and interconnection requirements are not considered in the study.

New Hampshire installed hydroelectric capacity of approximately 500 MW, have nameplate capacity equal to or less than 1.0 MW, making them potentially eligible for net metering. Hydroelectric includes a variety of generators, ranging from small run-of-river plants to large facilities with extensive reservoirs, such as the Comerford and Moore plants located along the Connecticut River in northwest New Hampshire. For this study, the seasonal hourly output of several existing hydroelectric facilities is used to understand the seasonal and locational variations that can be expected from smaller net-metered hydroelectric facilities.

Figure 4. Solar Irradiance and Hydro Sites[19] in New Hampshire



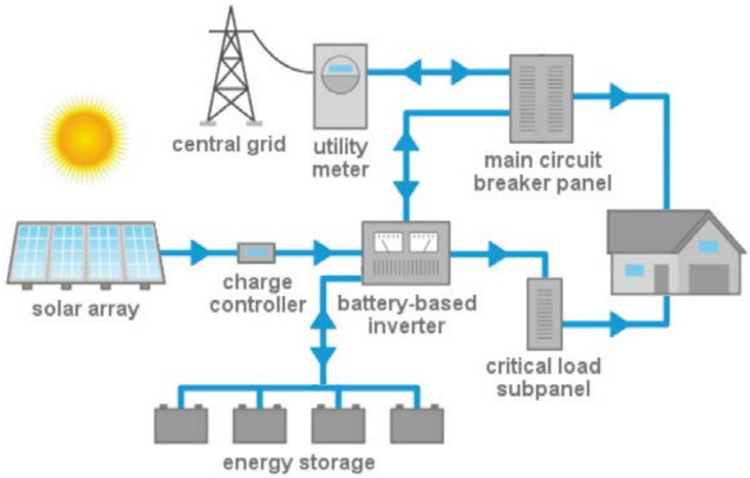
Source: National Renewable Energy Lab (NREL), https://maps.nrel.gov/nsrdb-viewer

Source: Energy Information Administration (EIA), https://www.eia.gov/state/?sid=NH#tabs-4

Figure 5 is an illustrative diagram of a solar PV array paired with battery storage for a residential application. In the analysis below, the pairing of solar PV production coincidence with energy storage is shown to possess the potential to produce output from renewable DG for hours during which capacity deficiencies occur, particularly at locations that peak in the late afternoon or early evening.[20]

[19] This map of hydroelectric generating facilities shows major facilities (greater than 5 MW and others not eligible for NEM) as well as smaller facilities, and is included for illustrative purpose only, as it shows significant waterways as well as transmission facilities.
[20] Solar PV-generated electricity can be diverted into an energy storage facility at times when the solar energy exceeds onsite load and then discharged at other times when it can effectively serve onsite or off-site load. In this manner, solar generated energy can be used at times when the solar PV array is not producing electricity.

Figure 5. Solar PV plus Storage Diagram



Source: Solar Power Now, https://solar-power-now.com/solar-power-storage/

1.6 Study Approach and Report Structure

The study approach consisted of three analytical steps:

- **Step 1:** Location Identification – Identify potential locations with expected capacity constraints and historical locations with past capacity constraints
- **Step 2:** Estimation of Investment Costs for Avoidance – Determine the value of potential avoided capacity investments at those locations
- **Step 3:** Economic Analysis and Mapping of DG Production Profiles with Distribution Capacity Needs – Perform economic analysis to estimate the benefit of avoidance and map representative DG production profiles with distribution capacity needs

This approach also allowed intermediate results to be provided to the LVDG stakeholder group through workshops during which questions and feedback from attendees were addressed. The three steps have also been used to organize the study report, with Section 2.0 covering Step 1, and so on. In addition, Section 5.0 summarizes findings and conclusions determined through the study and its analysis.

2.0 Location Identification (Step 1)

This section describes the analysis performed to identify locations on each EDC's distribution system (i.e., lines and substations) with capacity deficiencies, where capital investments potentially could be avoided through load reduction attributable to NEM-eligible DG.[21] Summary and aggregate location data is presented throughout this

[21] "Lines" refers to distribution circuits rated 34.5kV and below.

section. A complete list of all identified forward-looking locations is available in Appendix B.

1. The study scope required in-depth analysis for a subset of locations. The process applied to determine locations for detailed analysis included identifying and assessing all locations with qualifying capacity deficiencies.
2. Specific locations were then selected for further analysis under each load forecast that resulted in a planning criteria violation.

The selection process for specific locations is intended to ensure a sufficient number of distribution substations and lines are chosen for each of the three EDCs to evaluate the locational value of DG across the state for both historical and forward-looking capacity investments.

2.1 Screening Analysis

In Step 1, a screening analysis of all distribution lines and substations to identify locations where capacity deficiencies exist within the 10-year forward-looking study horizon was conducted. Line and equipment rating data for all sub-transmission and distribution assets was obtained from each of the EDCs for both normal (N-0) and contingency (N-1) conditions. Data values and methodologies to derive capacity deficiencies were confirmed through follow-up interviews with the EDCs and consultation with Commission Staff. Table 2 lists the total number of lines and substations that the study evaluated in the screening analysis.

Table 2. Number of Distribution Substation and Lines

EDC	Substations (Bulk & Non-Bulk)[22]	Distribution Lines (34.5 kV)	Distribution Lines (<34.5 kV)
Eversource	131	180	181
Liberty	14	0	61
Unitil	25	41	58

Source: Guidehouse

The study undertook the following steps for each EDC to perform the screening analysis of candidate locations to determine the value of avoided capacity investments:

1. Develop high and low load forecasts using the EDC's Base Case load forecast as a baseline (Section 2.2), to facilitate high and low sensitivity analysis
2. Analyze each EDC's capital plans and budgets to determine the cost of avoided capacity investments

[22] Bulk substations are those served by 115 kV transmission on the high side of the substation transformer; non-bulk substations are those served by 69 kV transmission or below on the high side of the substation transformer. The low side voltage of bulk substations ranges from 4.16kV to 34.5kV; whereas the low side voltage of non-bulk substations typically is 13.8kV or below.

3. Conduct a load versus capacity balance analysis to determine thermal capacity deficiencies for each year of the study:
    a. Assess forward-looking planning criteria versus historical practices
    b. Identify normal (N-0) and contingency (N-1) violations
4. Determine the magnitude and timing of capacity deficits for each of the three load forecast scenarios (low, base, and high), by location
5. Hold follow-up discussions with each EDC to confirm forecasted capacity deficiencies
6. Select a subset of locations for more detailed analysis

The Commission Staff and the EDCs then reviewed the results to confirm that the 16 locations selected:

- Include examples from each EDC's service territory and regions
- Provide a sample of future and historical projects, including circuits and bulk and non-bulk substations
- Include locations with identified deficiencies under various load growth forecasts
- Include winter and summer peaking locations
- Include midday and late-day peaking locations
- Include locations with small and large capacity deficiencies
- Include locations with normal and contingency overloads or performance violations
- Include locations where data is available to comprehensively analyze each site to determine the cost of traditional capacity solutions

More detail on the methodology and assumptions for load forecasting and violation screening is found in Appendix A.

2.2 Load Forecasts

Three load forecasts for the period of 2020-2029 were used to assess the range of capacity deficiencies and the associated value of load reductions at relevant locations.

- **Base Case:** The Base Case load forecast used the base load forecasts developed by each EDC with some minor modifications to consider the counterfactual case of no explicit additional future DG. This case is to account for business as usual assumptions.
- **High Case:** The High Case load forecast was based on the Base Case and included assumptions for aggressive penetration of electric vehicles (EV) in New Hampshire and lower than anticipated energy efficiency (EE) adoption and conservation. The High Case forecast also used the "Extreme" weather load

forecasts developed by each EDC and the counterfactual assumption of no additional future DG.

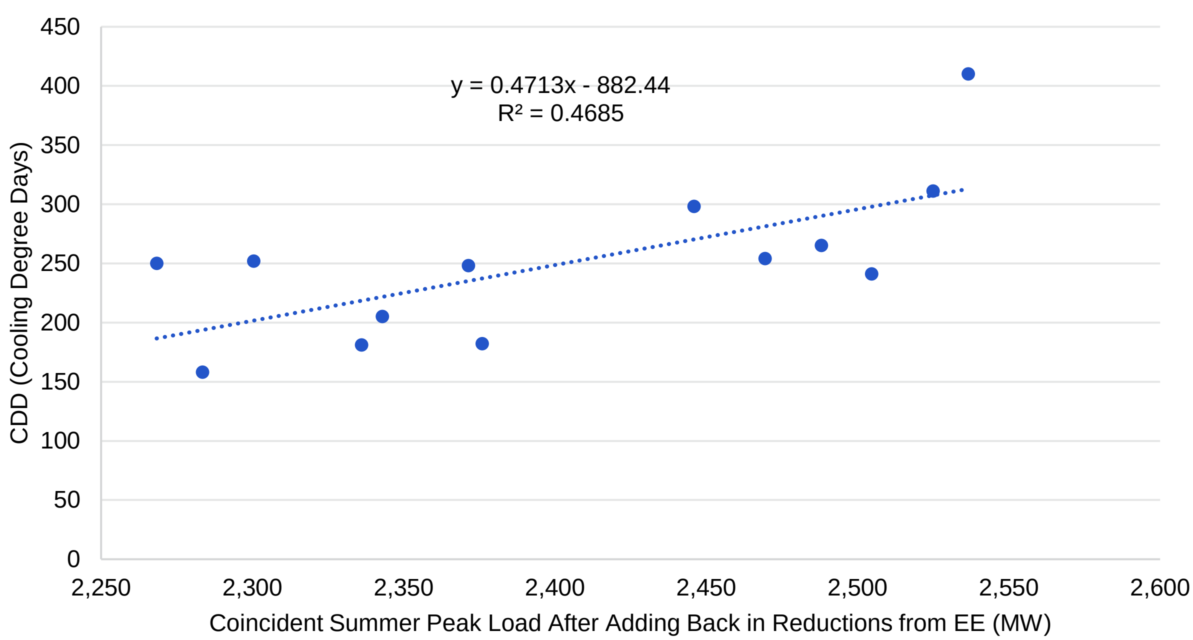
- **Low Case:** The Low Case load forecast was based on the Base Case and considered a lower estimate of electric load growth due to increases in levels of EE and overall increases in energy conservation activities. The Low Case used the "Average" weather load forecasts developed by each EDC and the counterfactual assumption of no additional future DG.

The following sections describe the load forecasting approach. First, analysis of the impact of economic factors on peak loads in New Hampshire is discussed. Then, the specific assumptions for each of the three load growth forecast cases is addressed. Finally, the resulting three load forecasts for each of the three EDCs are summarized.

2.2.1 Overview of Analysis of Factors on Peak Load Forecasts

The load forecast analysis for the Low and High Cases included a review of New Hampshire historical summer peaks coincident with the ISO-NE peak and historical economic variables. First, the study reviewed the past 28 years of coincident historical New Hampshire summer peaks using information available from ISO New England (ISO-NE) to determine the correlation between statewide economic factors and load. ISO-NE considers multiple variables for developing its New England and States Long-Run Energy Models. The three variables closely tied to economic factors include total state population, total real personal income, and real total gross state product. Limited correlation was found with data available on peak loads and statewide economic factors. The study focused on total real personal income, but also considered the other variables. A summary of the analysis of these variables is available in Appendix A.1.

Figure 6. Cooling Degree Days vs. Coincident Summer Peak Load After Adding Back in Peak Load Reductions from EE (2006-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

The study also reviewed the impact of weather conditions on historical peaks to determine if those conditions drove variations in peak loads over time. Figure 6 shows the results of this analysis. As Figure 6 displays, a strong correlation was found between cooling degree days and coincident summer peak load from 2006-2018.

Projections of future temperature conditions in the low and High Cases were not included, given that there is significant uncertainty about future temperature trajectories. However, the study team used the “Extreme” weather forecasts developed by the EDCs to inform the High Case and the “Average” weather forecasts developed by the EDCs to inform the Low Case. Those forecasts considered the impacts of historical extreme (95/5)[23] and average (50/50) temperatures on system peak load to develop load forecasts that have a lower or higher probability of occurrence than the base case (90/10). Economic growth assumptions did not impact the low or High Case forecasts due to the very low correlation of economic growth with summer peak load over the past 12 years.

The study also reviewed data on beneficial electrification related to building use and heating for consideration in the High Case. However, data specific to New Hampshire on beneficial electrification was not sufficient to include in the analysis. Beneficial electrification related to building use and heating is something that could be considered for future inclusion. The effect of electric vehicle adoption was considered in the High Case for this study.

The following sections address the base, low, and High Case load forecasts assumptions in greater detail.

2.2.2 Base Case Load Forecast

Table 3 presents a high level summary of each EDC’s load forecast methodology (i.e., Base Case) in use at the time this study was conducted, including assumptions for peak weather probability, existing DG, future DG, economic growth, EVs, and EE as compared to an industry standard practice Base Case summarized in the first column. Existing DG is embedded in all EDC load forecasts; the study made no adjustment to remove the existing DG. Eversource is the only utility that explicitly includes future DG growth in its forecast, based on ISO-NE projections, which was removed from the study forecasts to establish the counterfactual case.

[23] Electric utility load forecasts are generally separated into three weather forecast scenarios, each scenario with a probability or likelihood of occurrence. The figures in parenthesis following a forecast represent that likelihood. In the case of an extreme weather forecast a (95/5) represents a 1 in 20 year likelihood (or 5% probability) that the extreme load level will be exceeded.

Table 3. Summary of EDC Base Forecast Methodology

	Industry Standard Practice	Eversource	Liberty	Unitil
Peak Weather Probability	90/10	90/10	Liberty uses 95/5 extreme load forecast for the Base Case.	90/10 (System) – Past 5 years trend line for distribution system
Existing DG	Existing DG included	Existing DG included	Existing DG included	Existing DG included
Future DG	No future DG included	Very modest incremental amount of PV added based on internal Eversource projections.	No future DG explicitly included in system level load forecast	No future DG explicitly included in system level load forecast
Economic Growth	Average	Moody's Analytics New Hampshire level state profile	Employment and number of households from Moody's Analytics used in regression analysis	Economic growth not explicitly considered
EVs	None	None	None	None
Energy Efficiency	Average	Historical EE is implicitly included in system level forecast. Forecasted incremental EE is explicitly included based on internal Eversource projections.	Historical EE is implicitly included in system level forecast	Historical EE is implicitly included in system level forecast

Source: Guidehouse, Eversource, Liberty, Unitil

The forecast methodology uses ISO-NE's forecast of EE impacts from 2019 to 2028 on New Hampshire summer peak demand to inform base level forecasted EE, as shown in Table 4.

Table 4. Energy Efficiency Forecast

Year	EE Summer Peak MW Reduction
2019	120
2020	140
2021	159
2022	175
2023	190
2024	204
2025	215
2026	225
2027	233
2028	240

Source: ISO-NE

2.2.3 High Case Load Forecast

The high load forecast is based on low EE participation, extreme weather, and aggressive EV penetration. Economic factors were not considered in view of the poor correlation between statewide economic factors and summer peak loads. Table 5 shows a summary of the high load forecast methodology for each EDC.

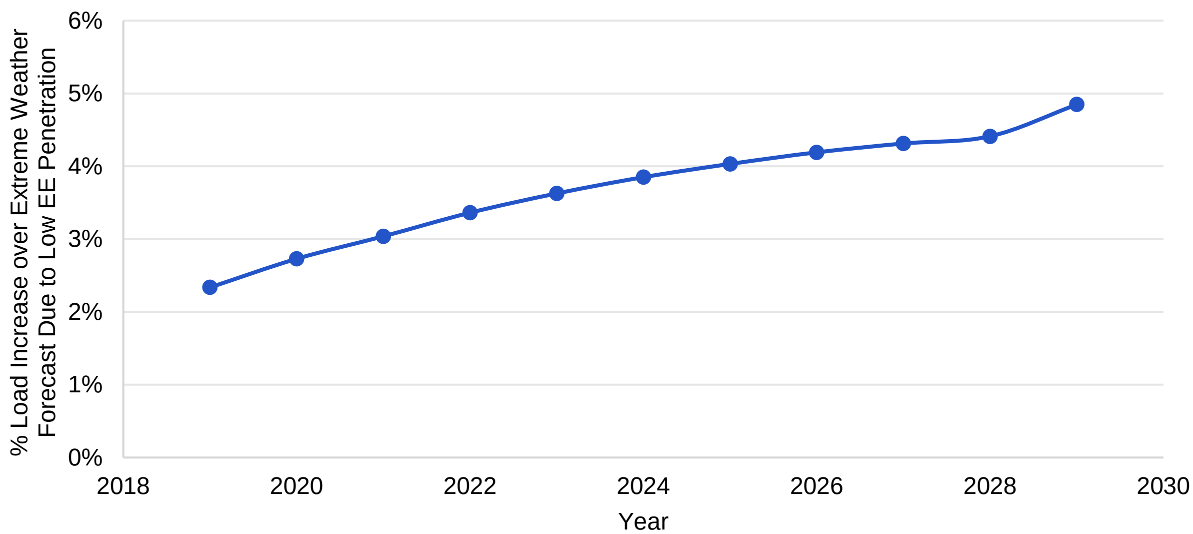
Table 5. Summary of EDC High Load Forecast Methodology

	Eversource	Liberty	Unitil – Seacoast	Unitil – Capital
Aggressive EV	✓	✓	✓	✓
Low EE	✓	✓	✓	✓
Extreme Weather (95/5)	✓	✓	✓	✓

Source: Guidehouse

To determine the impact of lower than forecasted EE participation, the forecasted EE summer peak MW reduction statewide for the Base Case (see Table 4) was left unchanged for the High Case. To determine the higher load (net of EE and PV impacts) for the High Case forecast, the extreme weather (95/5) load forecast provided by each EDC was used. The resulting lower percentage of EE penetration for the High Case is derived by dividing the Base Case EE forecast by the increased extreme weather forecast, as shown in Figure 7 (for example, the 3.9% shown in 2024 is 50% of 7.8%, which is 2,445 MW of EE reduced load in 2024 divided by 2,645 MW gross projected load in that year).[24]

Figure 7. High Case – Load Impact from Low Energy Efficiency Penetration



Source: Guidehouse

The forecast methodology referenced a 2019 Navigant Research (now Guidehouse Insights) report that forecast EV population under different scenarios for the US and Canada. Guidehouse Insights developed a forecast of total battery EV (BEV) population for New Hampshire for three scenarios. The study leveraged the aggressive scenario

[24] Load and energy efficiency numbers sourced from the 2019 CELT Forecast Detail: ISO-NE Control Area, New England States, RSP Sub-areas, and SMD Load Zones.

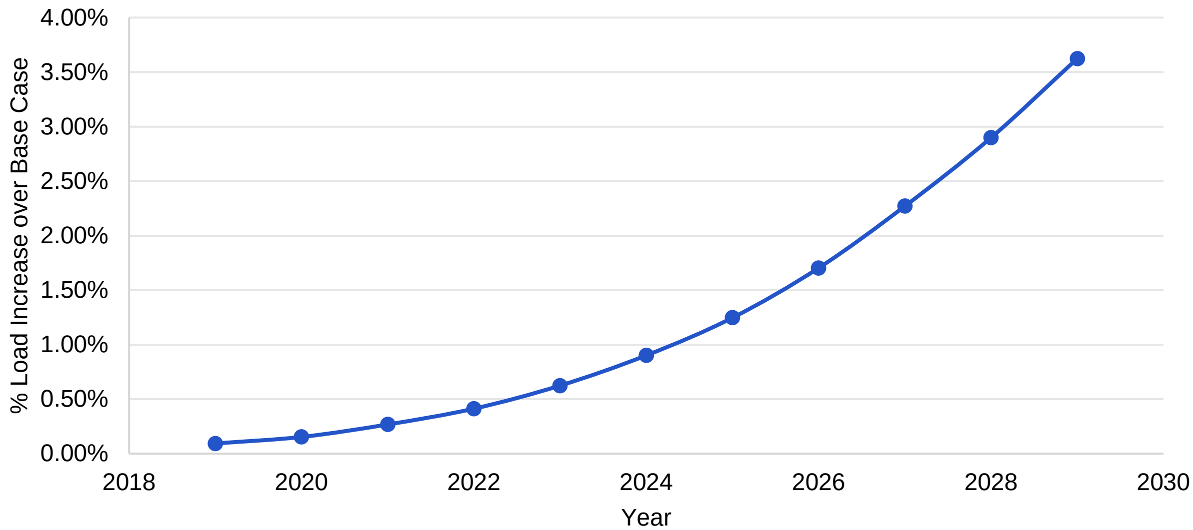
for the High Case analysis, as shown in Table 6 and Figure 8. In this analysis, there is a large decrease in battery price and the continuation of national incentives for EVs.

Table 6. EVs Load Forecast[25]

Scenario	Quantity of BEV by 2029
Conservative	69,200
Base	76,900
Aggressive	82,600

Source: Guidehouse

Figure 8. High Case – Load Impact from Aggressive EV Growth



Source: Navigant Research (now Guidehouse Insights): Market Data: EV Geographic Forecast – North America

2.2.4 Low Case Load Forecast

The low load forecast is based on high EE participation, average weather forecast, and no EV penetration. Similar to the high load growth forecast, economic factors were not considered in view of the poor correlation between statewide economic factors and summer peak loads. Table 7 shows a summary of low load forecast methodology for each EDC.

[25] Using results of Guidehouse Insights' Vehicle Adoption Simulation Tool (VASTTM) for other regions, the study assumed 1.2 kWpc/BEV to develop a peak load impact.

Table 7. Summary of EDC Low Load Forecast Methodology

	Eversource	Liberty	Unitil – Seacoast	Unitil – Capital
No EV	✓	✓	✓	✓
High EE	✓	✓	✓	✓
Average Weather (50/50)	✓	✓	✓	✓

Source: Guidehouse

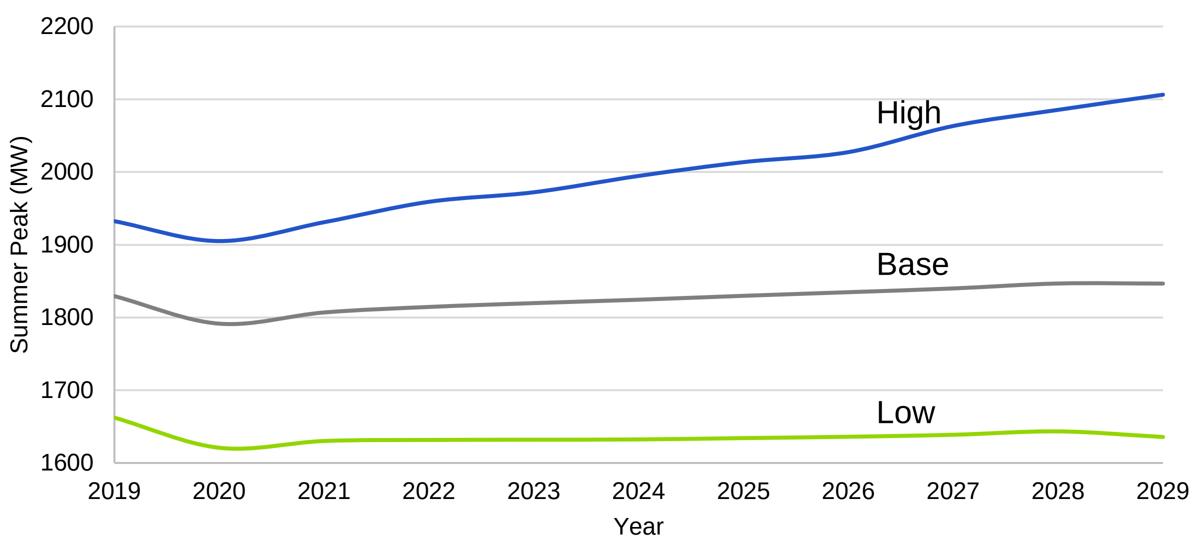
To account for higher than projected EE participation, the average weather forecast for each EDC was decreased by 50% of the forecast of statewide EE peak impacts (Table 4) divided by forecasted total state summer peak load excluding EE and PV impacts.

2.2.5 Load Forecasts by EDC

The base, low, and high forecasts vary across the three EDCs. The base load forecast compound annual growth rates (CAGR) from 2020 to 2029 were 0.38%, 0.24%, 1.01%, and 1.18% for Eversource, Liberty, the Unitil-Seacoast region, and the Unitil-Capital region, respectively. The low forecast CAGRs developed for this study from 2020 to 2029 were 0.1%, -0.02%, -0.21%, and -0.76% for Eversource, Liberty, the Unitil-Seacoast region, and the Unitil-Capital region, respectively. The high forecast CAGRs developed from 2020 to 2029 were 1.12%, 0.83%, 1.78%, and 1.18% for Eversource, Liberty, the Unitil-Seacoast region, and the Unitil-Capital region, respectively. These forecast results are shown graphically for each EDC below.

Figure 9 shows the base, high, and low load forecast results for Eversource. The resulting range between the High and Low Case for Eversource is 470 MW by 2029. The initial dip in the year 2020 is caused by the difference between the actual sum of the summer peak coincident loading across the five Eversource regions (Northern, Southern, Western, Central and Eastern) and the forecasted 90/10 system total summer peak forecast for 2020.

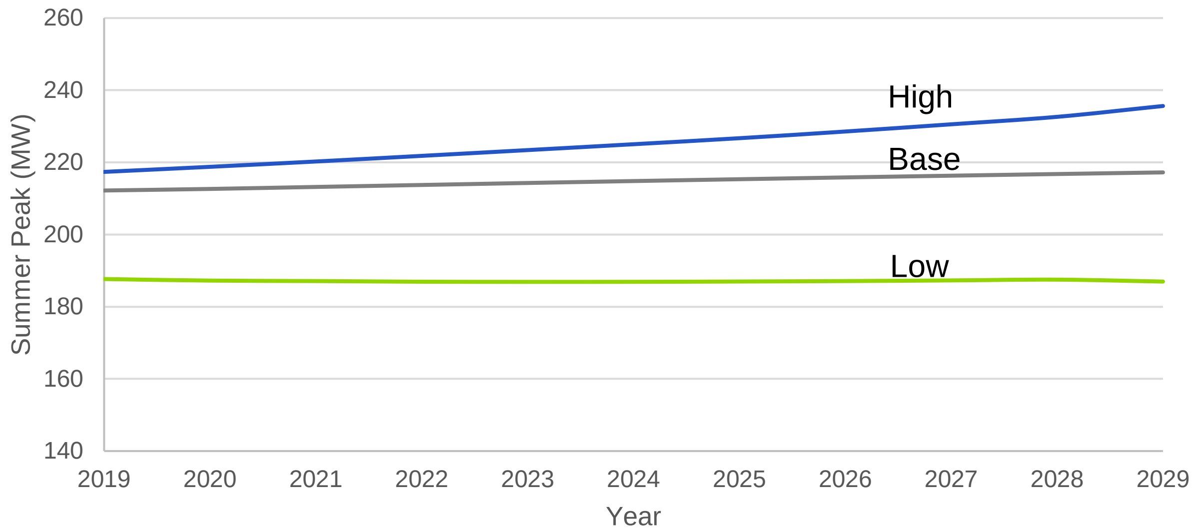
Figure 9. Eversource Load Forecast (Base, Low, High)



Source: Guidehouse, EDC data

Figure 10 shows the base, high, and low load forecast results for Liberty. The resulting range between the high and Low Case for Liberty is 49 MW by 2029. The range between the high and Base Case is smaller compared to Eversource because of Liberty's use of 95/5 extreme weather adjustment factor in its base forecast.[26]

Figure 10. Liberty Load Forecast (Base, Low, High)

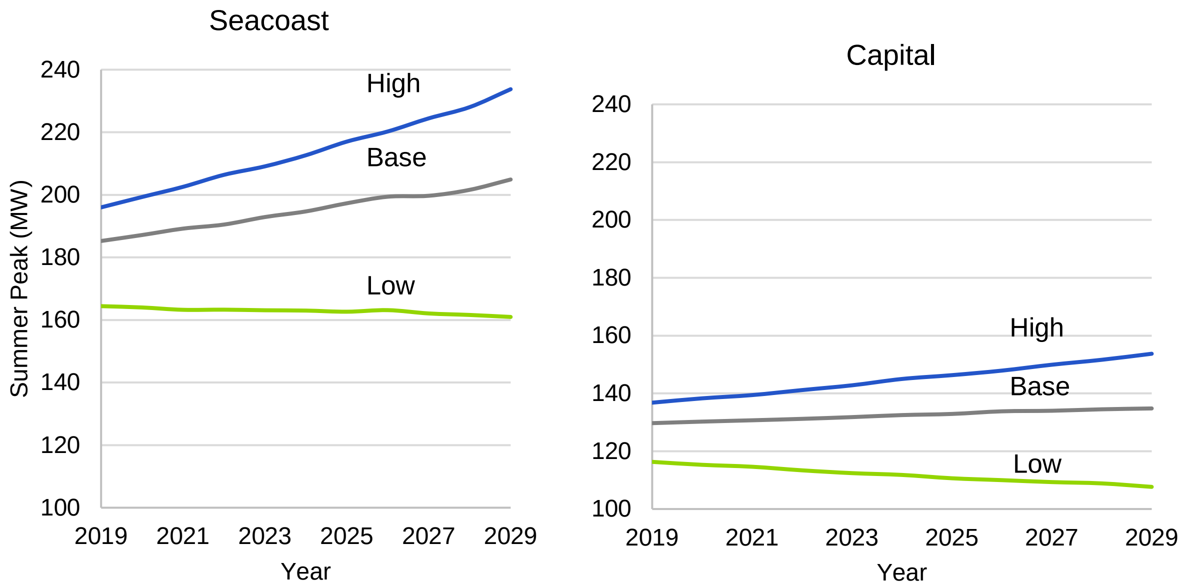


Source: Guidehouse, EDC data

Figure 11 presents the base, high, and low load forecast results for Unitil. The resulting range between the high and Low Case for Unitil is 73 MW for the seacoast region, and 46 MW for the capital region by 2029.

[26] NH PUC. Docket No. 19-064. Liberty Utilities Request for Change in Permanent Rates. Order No. 26, 376 Approving Settlement and Permanent Rates. (June 30, 2020) Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-064/LETTERS-MEMOS-TARIFFS/19-064_2020-05-26_GSEC_STIPULATION_SETTLEMENT_AGRMT.PDF;
see also, Stipulation and Settlement Agreement (May 26, 2020), Attachment 8. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-064/LETTERS-MEMOS-TARIFFS/19-064_2020-05-26_GSEC_ATT_STIPULATION_SETTLEMENT_AGRMT.PDF

Figure 11. Unitil Load Forecast (Base, Low, High for Seacoast and Capital Regions)



Source: Guidehouse, EDC data

2.3 Capacity Deficiency Screening by Location

Based on a screening analysis of historical and forward-looking capacity deficiencies, the study team identified locations for detailed analysis. The screening analysis addressed both normal and contingency capacity deficiencies on distribution lines and substations. The full screening analysis has been provided to the New Hampshire Public Utilities Commission Staff. The study considers other violations at the component level, such as unacceptable steady state voltages, protective relaying limits or miscoordination, or other criteria applied by the EDCs. However, the LVDG analysis focuses on candidate locations with violations of capacity limits. The analysis also excludes minor violations that may be corrected by low cost investments such as installation of capacitors or replacement of distribution line transformers. Based on the screening analysis, the amount of capacity needed to address violations at each location was determined, with reference to load levels exceeding normal or emergency capacity limits.

The study relied on EDC data and planning criteria to conduct the screening analysis, including loading limits for substation transformers or individual circuits to support the findings. The study team also reviewed each EDC's 5 and 10-year planning studies, capital budgets, and cost data to support the derivation of future and historical capacity deficiencies. Forward-looking capacity deficiencies are based on current EDC planning criteria, whereas planning criteria for prior investments are based on criteria and forecasts that were in effect at the time the decision was made to proceed with the distribution capacity investment. Table 8 presents the prior (historical investments) and current (forward-looking investments) planning criteria used to determine capacity deficiencies for each EDC.

Table 8. EDC Planning Criteria[27]

Condition	Distribution Circuit (Prior)	Distribution Circuit (Current)	Substation Transformer (Prior)	Substation Transformer (Current)
(1) Eversource[28]				
Normal (N-0)	• 100% of normal rating	• 100% of normal rating	• 100% of normal rating	• Bulk: 75% of normal rating • Non-Bulk: 100% TFRAT
N-1 Contingency	• 100% of LTE rating	• 100% of LTE rating	• Non-Bulk: 100% of LTE rating • Bulk: 100% of LTE rating with allowable 720 MWhr unserved load (30MW for 24 hours)	• Non-Bulk: 100% of LTE rating • Bulk: 100% of emergency rating with no allowable loading violations[29]
(2) Liberty				
Normal (N-0)	• 75% of normal rating	• 100% of normal rating	• 75% of normal rating	• 100% of normal rating
N-1 Contingency	• Load transfer to nearby feeders within LTE rating • 24-hour repair	• Load transfer to nearby feeders within LTE rating • 24-hour repair	• Load transfer to nearby transformer with 24 hours within LTE rating • Repair or installation of mobile w/in 24 hours	• Load transfer to nearby transformer with 24 hours within LTE rating • Repair or installation of mobile w/in 24 hours
(3) Unitil				
Normal (N-0)	• 90% of normal seasonal rating	• 90% of normal seasonal rating	• 90% of normal seasonal rating	• 90% of normal seasonal rating
N-1 Contingency	• Load transfer to nearby feeders within seasonal rating	• Load transfer to nearby feeders within seasonal rating	• Load transfer to spare or mobile transformer within 24 hours to within seasonal rating • Repair or installation of spare or mobile w/in 24 hours	• Load transfer to spare or mobile transformer within 24 hours to within seasonal rating • Repair or installation of spare or mobile w/in 24 hours

Source: EDC Planning Criteria

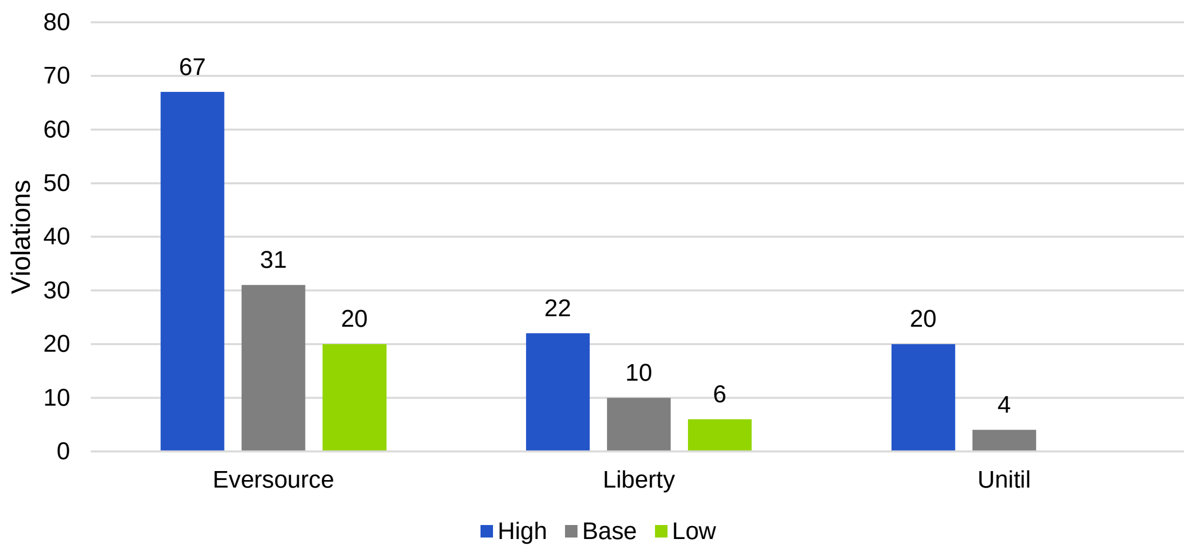
The project team performed the screening analysis for base, low, and high 10-year forward-looking scenarios and 15-year load forecasts for historical distribution capacity

[27] As of June 2020.
[28] Eversource recently revised its planning criteria and disagreement exists between Eversource, Commission Staff, and the Office of the Consumer Advocate (OCA) regarding the need for those revisions. *See* Order No. 26,362 at 5 (June 3, 2020); *see* also Docket No. DE 19-139, Settlement of the Parties, Attachment A (March 11, 2020) (describing recent changes to SYSPLAN-008, which changes the way Eversource calculates bulk transformer preload, and SYSPLAN-010, which previously allowed for a loss of up to 30 MW for up to 24 hours, but no longer allows for any loss of load after initial restoration).
[29] Back up capacity can be provided by feeder ties provided the transformer is loaded to its long-term emergency ratings. The in-service transformer following a contingency may be loaded to its short-term emergency rating if transfers, up to three, can be made within 15 minutes and reduce the in-service transformer loading to below its long-term emergency rating.

investments. The study team consulted with the EDCs to confirm all capacity deficiencies identified at the substation and distribution circuit levels.

Figure 12 presents the number of distribution substations and distribution circuit capacity deficiencies, collectively, for each EDC under the high load forecast scenario. It includes both normal and contingency capacity deficiencies for lines and substations for each EDC. Of the 696 locations reviewed, there are 109 total capacity deficiencies in the high forecast scenario. There are 45 total capacity deficiencies in the base load forecast scenario, with many of the deficiencies occurring further into the study period compared to the high scenario, where many deficiencies occur in 2020 or shortly thereafter. There are 26 total deficiencies in the low forecast scenario, with many of these occurring later in the study period. There are 64 deficiencies that only occur due to the high load forecast.

Figure 12. Forward-Looking Capacity Deficiencies by EDC



Source: Guidehouse, EDC data

Table 9 presents the 45 Base Case capacity deficiencies for each EDC, listed by type of asset upgrade, region, first year the deficiencies occurs and the violation type (i.e., normal or contingency, or both). Appendix B shows all the 109 forward-looking capacity deficiencies across the three EDCs. It also includes the load forecast (low, base, or high) triggering the violation, the first year the violation occurs for that forecast, and the violation type that triggered the capacity deficiency.

The projected violations as measured by capacity deficiencies for the three EDC beginning in 2020 is approximately 107 MW and increases to 147 MW by 2029 for the base load forecast. Total capacity deficiencies in 2029 for the low forecast is 63 MW and 316 MW for the high load forecast. A substantial number of capacity deficiencies occur in 2020, the first year of the forward-looking segment of the study, in large part due to recent changes in planning criteria by Eversource.

Table 9. Base Case Violations (Capacity Deficiencies)

No.	EDC	Asset Type	Asset Name[30]	Substation	Region	Voltage	Forecast	First Violation Year	Violation Type
1	Eversource	Bulk Substation	Ashland		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
2	Eversource	Bulk Substation	Beebe River		Northern	34.5	Base	2020	N-1,
3	Eversource	Bulk Substation	Bridge St. 4kv		Southern	4.16	Base	2020	N-1, 75% Tx Capacity
4	Eversource	Bulk Substation	Chestnut Hill		Western	34.5	Base	2020	N-1, 75% Tx Capacity
5	Eversource	Bulk Substation	Dover		Eastern	34.5	Base	2020	N-1, 75% Tx Capacity
6	Eversource	Bulk Substation	Eddy		Central	34.5	Base	2020	75% Tx Capacity
7	Eversource	Bulk Substation	Great Bay		Eastern	34.5	Base	2020	N-1, 75% Tx Capacity
8	Eversource	Bulk Substation	Huse Road		Central	34.5	Base	2020	N-1, 75% Tx Capacity
9	Eversource	Bulk Substation	Laconia		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
10	Eversource	Bulk Substation	Lawrence Road		Southern	34.5	Base	2020	N-1,
11	Eversource	Bulk Substation	Long Hill		Southern	34.5	Base	2020	75% Tx Capacity
12	Eversource	Bulk Substation	Madbury		Eastern	34.5	Base	2020	75% Tx Capacity
13	Eversource	Bulk Substation	Mill Pond		Eastern	12.47	Base	2020	N-1,
14	Eversource	Bulk Substation	Monadnock		Western	34.5	Base	2020	N-1, 75% Tx Capacity
15	Eversource	Bulk Substation	North Woodstock		Northern	34.5	Base	2020	N-1,
16	Eversource	Bulk Substation	Pemigewasset		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
17	Eversource	Bulk Substation	Portsmouth		Eastern	34.5	Base	2020	N-1, 75% Tx Capacity
18	Eversource	Bulk Substation	Reeds Ferry		Central	34.5	Base	2020	N-1, 75% Tx Capacity
19	Eversource	Bulk Substation	Resistance		Eastern	34.5	Base	2020	N-1,
20	Eversource	Bulk Substation	Rimmon		Central	34.5	Base	2020	75% Tx Capacity
21	Eversource	Bulk Substation	Saco Valley		Northern	34.5	Base	2020	N-1,
22	Eversource	Bulk Substation	South Milford		Southern	34.5	Base	2020	N-1, 75% Tx Capacity

[30] The inclusion of a substation in the list of candidate locations does not represent a determination regarding the continued operation of that substation, which instead would be addressed in a utility rate case or other future proceeding before the Commission. The assumption that any listed substation will continue in operation is solely for purposes of the LVDG study; in view of the current lack of certainty regarding future substation status, that study assumption will not be controlling in any such future case or proceeding.

Table 9. Base Case Violations (Capacity Deficiencies)

No.	EDC	Asset Type	Asset Name[30]	Substation	Region	Voltage	Forecast	First Violation Year	Violation Type
23	Eversource	Bulk Substation	White Lake		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
24	Eversource	Bulk Substation	Whitefield		Northern	34.5	Base	2020	N-1,
25	Eversource	34.5 kV Circuits	380_65	Madbury	Eastern	34.5	Base	2020	Normal
26	Eversource	Non-34.5 kV distribution circuits	2W2_41	Lochmere	Northern	12.47	Base	2020	Normal
27	Eversource	Non-34.5 kV distribution circuits	18H1_21	Millyard	Southern	4.16	Base	2020	Normal
28	Eversource	Non-34.5 kV distribution circuits	41H2_61	North Dover	Eastern	4.16	Base	2020	Normal
29	Eversource	Non-34.5 kV distribution circuits	76W1_31	North Keene	Western	12.47	Base	2020	Normal
30	Eversource	Non-34.5 kV distribution circuits	37H1_42	Tilton	Northern	4.16	Base	2020	Normal
31	Eversource	Non-34.5 kV distribution circuits	37H2_42	Tilton	Northern	4.16	Base	2020	Normal
32	Liberty	Transformer	L4	Olde Trolley 18	Salem NH	13.2	Base	2022	>100% Normal
33	Liberty	Transformer	L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal
34	Liberty	Transformer	L2	Salem Depot 9	Salem NH	13.2	Base	2020	>100% of Emergency Rating
35	Liberty	Transformer	T1	Vilas Bridge 34	Bellows Falls	13.2	Base	2020	>100% of Emergency Rating
36	Liberty	Feeders	18L4	Olde Trolley 18	Salem NH	13.2	Base	2022	>100% Normal
37	Liberty	Feeders	9L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal
38	Liberty	Feeders	15H1	Monroe 15	Monroe	2.4	Base	2020	>100% Normal
39	Liberty	Feeders	11L1	Craft Hill 11	Lebanon	13.2	Base	2022	>100% Normal
40	Liberty	Feeders	16L1	Mount Support 16	Lebanon	13.2	Base	2022	>100% Normal
41	Liberty	Feeders	16L4	Mount Support 16	Lebanon	13.2	Base	2021	>100% Normal
42	Unitil	Transformer	Bow Junction 7T2 Xfmr	Bow Junction	Capital	13.8	Base	2022	>90% Normal
43	Unitil	Transformer	Bow Bog 18T2 Xfmr	Bow Bog	Capital	13.8	Base	2024	>90% Normal
44	Unitil	Transformer	Dow’s Hill 20T1	Dow’s Hill	Seacoast	4.16	Base	2021	>90% Normal
45	Unitil	Circuit	18W2	Bow Bog	Capital	13.8	Base	2025	>90% Normal

Source: Guidehouse, EDC data

Following the review of EDC historical capacity violations, 13 historical capacity deficiencies projects should also be considered for inclusion in the subset of locations for detailed evaluation.

Table 10 summarizes the historical projects by EDC and year in service. Some of these show a year in service of 2020 but the projects had already begun in prior years, such as 2018 or 2019.

Table 10. Summary of Historical Projects

No.	EDC	Project	Year in Service
1	Eversource	Mill Pond Substation	2017
2	Eversource	Rimmon Substation	2020
3	Eversource	Bristol Substation	2015
4	Eversource	White Lake Substation	2020
5	Eversource	Pemi Substation	2020
6	Eversource	West Rd Overloaded Steps	2020
7	Eversource	388 Line Overload	2020
8	Eversource	34.5kV lines Rimmon Substation	2016
9	Eversource	Londonderry	2015
10	Liberty	Mount Support	2017
11	Liberty	Golden Rock Substation	2019
12	Unitil	New Sub-transmission Lines – Broken Ground to Hollis	2020
13	Unitil	Kingston Substation	2017

Source: Guidehouse, EDC data

The following sections describe the selection criteria and how it is applied to derive a subset of locations with capacity deficiencies for further analysis. The objective of the selection process is to ensure a sufficient number of locations, from the 109 forward-looking and 13 historical projects, 122 potential sites, to accurately analyze the indicative value of avoiding capacity investments.

2.3.1 Location Selection Criteria

The study team developed guidelines to select a subset of locations for in-depth analysis. Selection criteria were designed to ensure that the subset of locations represents different types of future and historical capacity investments, and various locations throughout the state. The study team specified that the subset of locations for detailed analysis should include the following:

- A proportional share of locations based on EDC load and service territories served
- Each major region served by each EDC, if possible[31]
- Winter and summer peaking locations
- Midday and late-day peaking locations
- Bulk and non-bulk substations
- Small and large capacity deficiencies
- Normal and contingency overloads or performance violations
- Historical and forward-looking capacity investments

[31] Some regions had few, or no, capacity deficiencies under the Base Case analysis.

The study team determined that a subset of 16 locations (of the 122 capacity deficiencies identified) is sufficient to meet the specified selection criteria. Section 2.3.2 presents the selected subset of locations.

2.3.2 Locations Selected for In-Depth Analysis

Table 11 presents the final list of locations representing each of the EDCs, based on the selection criteria described in Section 2.3.1. To satisfy the selection criteria, the study team includes locations with capacity deficiencies for a range of low, base, and high load growth forecasts. For example, for Eversource, the only non-bulk substation violation occurred for the high growth scenario (Location Numbers 5 and 6 in Table 11).

Table 11. Locations Selected for In-Depth Analysis

No.	EDC	Description	Region	First Year of Capacity Deficiency[32]	First Year Cap. Deficit (MW)[33]	Selection Criteria
1	Eversource	Pemigewassett (Pemi) Substation (Bulk)	Northern	2020	8	Base case transformer normal violation
2	Eversource	Portsmouth Substation (Bulk)	Eastern	2020	12	Base case transformer normal violation
3	Eversource	South Milford Substation (Bulk)	Southern	2020	23	Base case contingency violation
4	Eversource	Monadnock Substation (Bulk)	Western	2020	2	Base case transformer normal violation
5	Eversource	East Northwood Substation (Non-Bulk)	Eastern	2021- High	0.06 – High	High forecast LTE violation
6	Eversource	Rye Substation (Non-Bulk)	Eastern	2022- High	0.07 – High	High forecast LTE violation
7	Eversource	Bristol Substation (Non-Bulk)	Northern	2015	0.04	Base case LTE violation
8	Eversource	Madbury ROW Circuit (34.5 kV)	Eastern	2020	3	Base case normal capacity violation
9	Eversource	North Keene Circuit (12.47 kV)	Northern	2028- High	0.1- High	High forecast normal capacity violation
10	Eversource	Londonderry Circuit (34.5 kV)	Southern	prior to 2014	0.6	Base case normal capacity overload
11	Liberty	Vilas Bridge Substation (Non-Bulk)	Walpole	2020	1	Base case LTE violation
12	Liberty	Mount Support Substation (Bulk)	Lebanon	2014	0.4	Base case normal capacity violation
13	Liberty	Golden Rock Substation (Bulk)	Salem	2019	10	Base case normal capacity violation
14	Unitil	Bow Bog Substation (Non-Bulk)	Capital	2024- High	0.1- High	Base case violation
15	Unitil	Dow's Hill Substation (Bulk)	Seacoast	2020- High	0.04 – High	Base case violation
16	Unitil	Kingston Substation (Bulk)	Seacoast	prior to 2014	6	Base case violation

Source: Guidehouse, EDC data

[32] For historical investments, the first year of capacity deficiency is the year the investment went into service; for forward-looking investments, the first year of capacity deficiency is the in-service year.
[33] Base case unless otherwise noted; for example, "High" is indicated if no violations occurred for the Base Case load forecast.

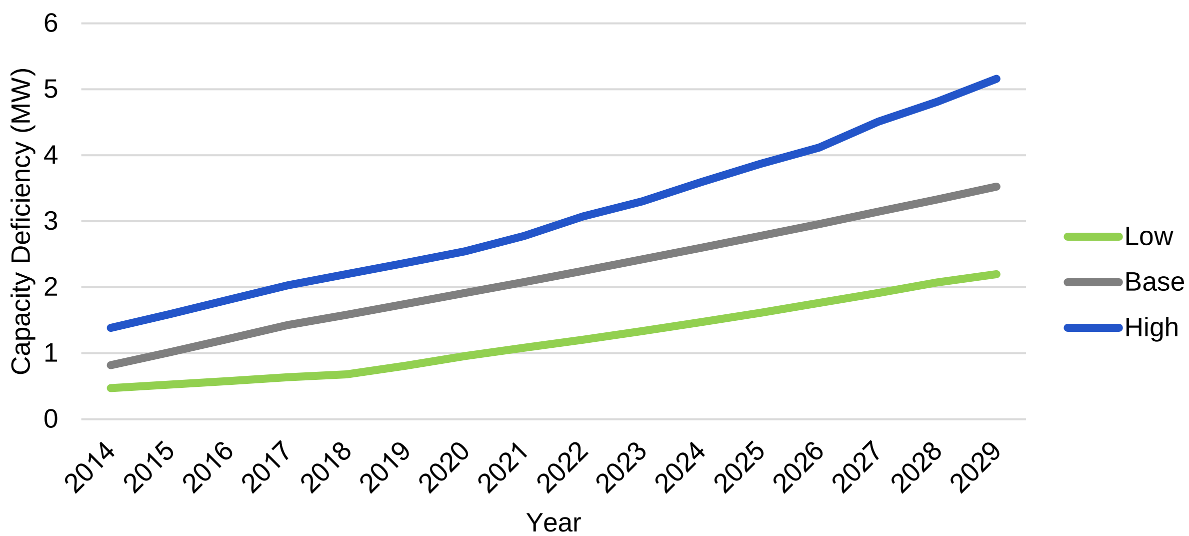
The cost of traditional distribution capacity investments to address deficiencies for each of the 16 locations and the potential value of avoidance via DG is presented in Section 3.0.

2.3.3 Distribution Capacity Deficiency Forecasts for Selected Locations

This section summarizes the results of the screening analysis at each of the 16 locations selected for detailed analysis. For each EDC, capacity deficiency forecasts are presented under the base, low, and high forecasts for the 16 selected locations. It includes illustrations of annual capacity deficiencies for each EDC.

Figure 13 and Figure 14 present historical and forward-looking capacity deficiencies for Eversource. The magnitude of the deficiencies is lower in prior years compared to forward-looking deficiencies, largely due to the change in system planning criteria. That change results in an increase in the number and magnitude of deficiencies, many of which occur in 2020, or in years shortly thereafter.

Figure 13. Historical Location Capacity Deficiencies – Eversource[34]

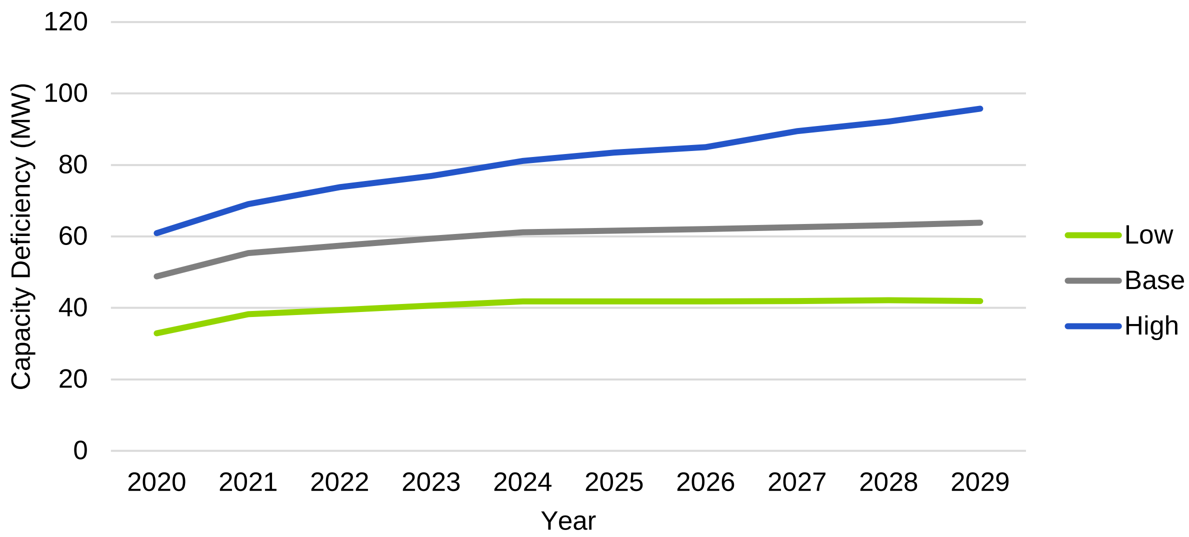


Source: Guidehouse, EDC data

Capacity deficiencies are projected to increase relatively sharply in 2020 and 2021, but taper off beyond these years for the low and base load forecasts for the selected Eversource locations.

[34] Projected capacity deficiencies based on load forecast prepared at the time a decision was made to invest in the project.

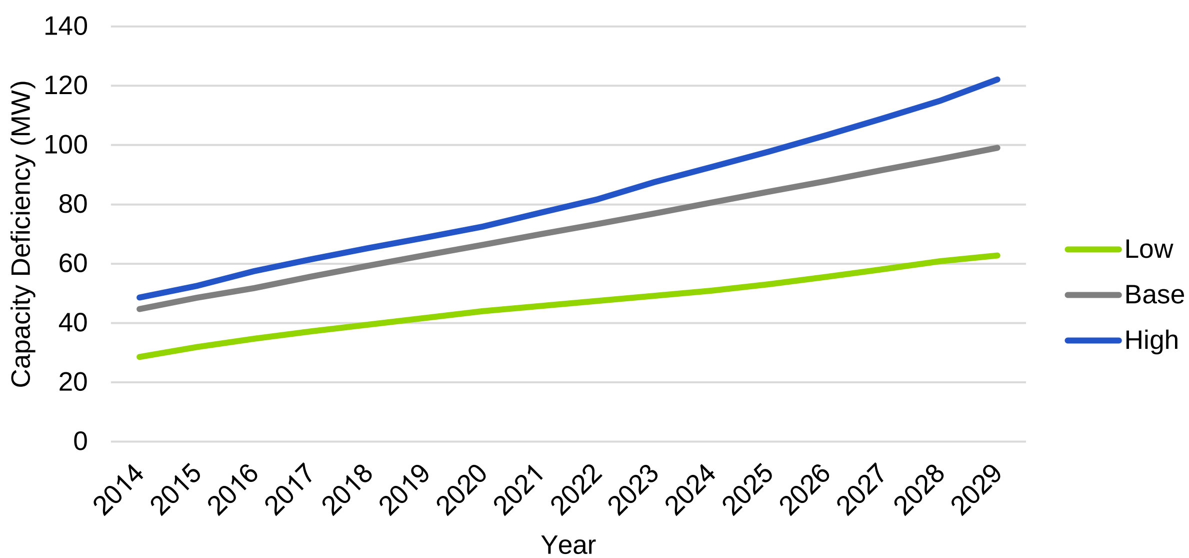
Figure 14. Forward-Looking Location Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

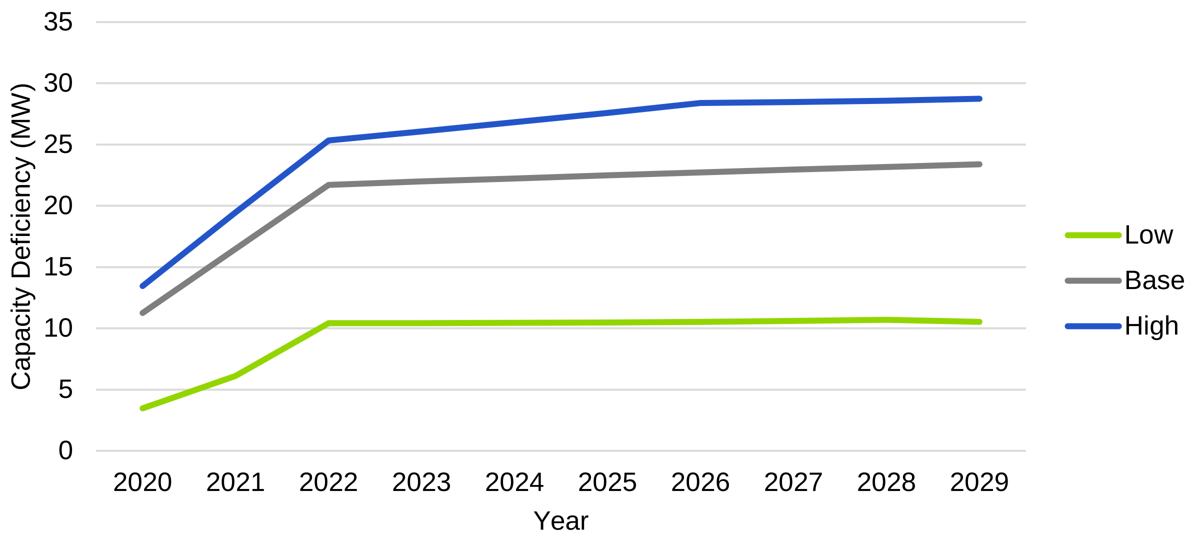
Figure 15 presents capacity deficiencies by year for Liberty. Large capacity deficiencies occur in prior years, as a major project is a previously completed project. Figure 16 presents the forward-looking capacity deficiencies by year for Liberty.

Figure 15. Historical Location Capacity Deficiencies – Liberty



Source: Guidehouse, EDC data

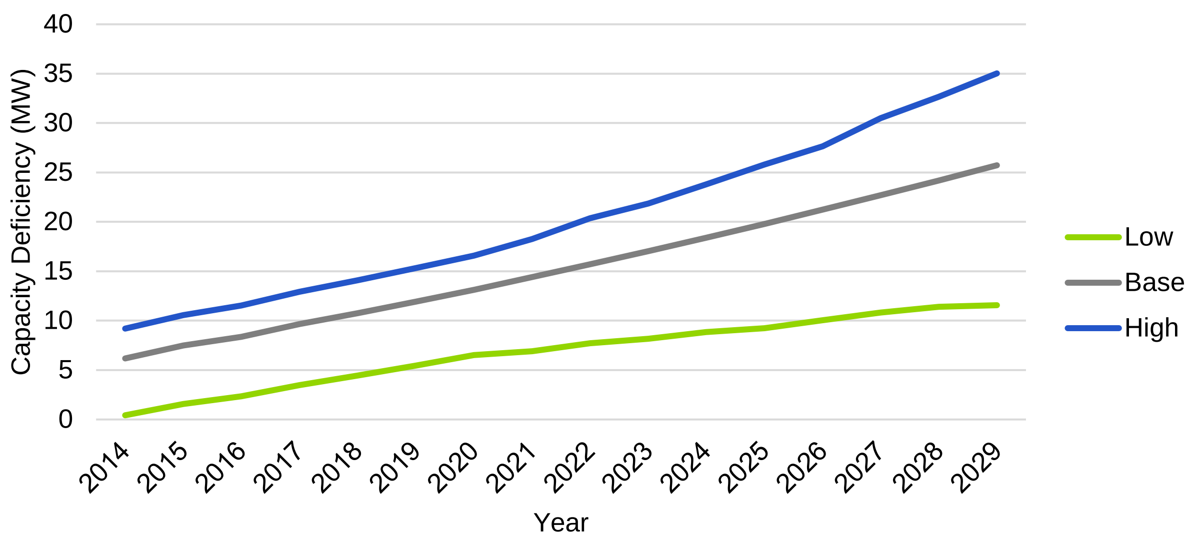
Figure 16. Forward-Looking Location Capacity Deficiencies – Liberty



Source: Guidehouse, EDC Data

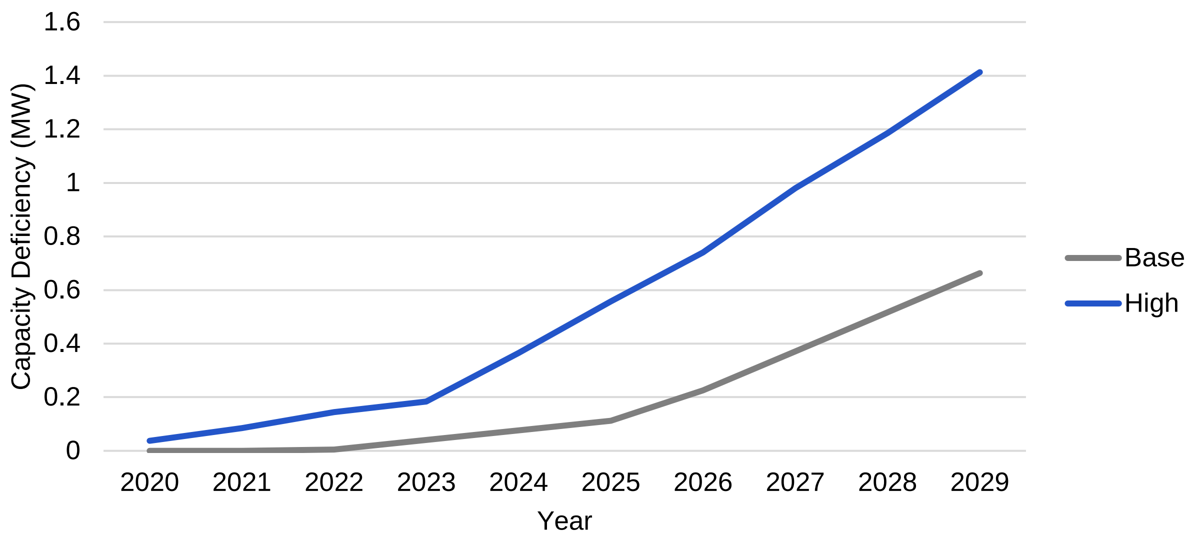
Figure 17 and Figure 18 present historical and forward-looking capacity deficiencies by year for Unitil. As shown in Figure 17, similar to Liberty, a major project completed in prior years caused large capacity deficiencies to occur in early years and increase steadily throughout the study timeframe as the magnitude of deficiencies was projected to increase at a high rate due to load growth. Figure 18 shows the two forward-looking Unitil projects that are minor non-bulk substations overloads with the deficiencies first occurring in later years (there are no capacity deficiencies for the low forecast).

Figure 17. Historical Location Capacity Deficiencies – Unitil



Source: Guidehouse, EDC data

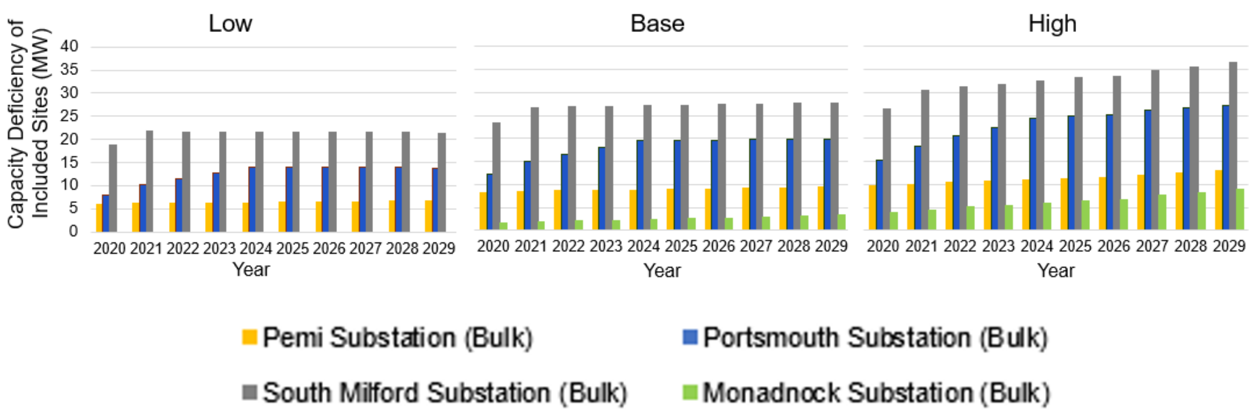
Figure 18. Forward-Looking Location Capacity Deficiencies – Unitil



Source: Guidehouse, EDC Data

Figure 19 presents selected bulk substation capacity planning criteria violations for Eversource under the low, base, and high load forecasts. Both the magnitude of the capacity deficiency and the number of locations with violations varies by the load forecast scenario. However, capacity deficiencies are highest for bulk substations due to the amount of load served and a recent change in Eversource's capacity planning criteria for bulk substations.

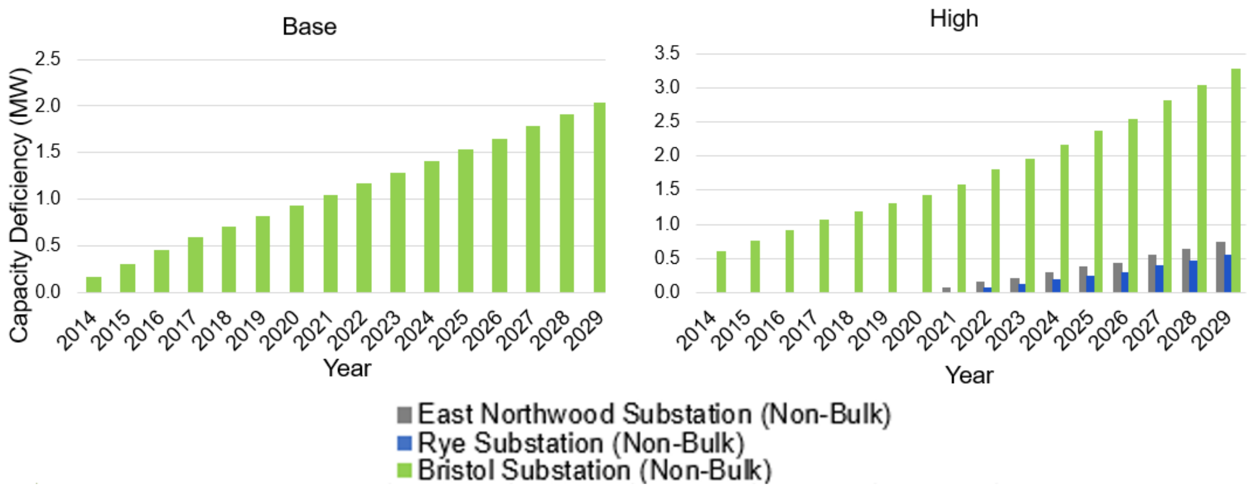
Figure 19. Bulk Substation Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

Figure 20 presents selected non-bulk substation capacity planning criteria violations for Eversource. Non-bulk substations typically have lower capacity ratings and serve fewer customers compared to bulk substations; hence, the magnitude of capacity deficiencies is lower than bulk substations. There are no non-bulk substation future capacity deficiencies during the Low Case.

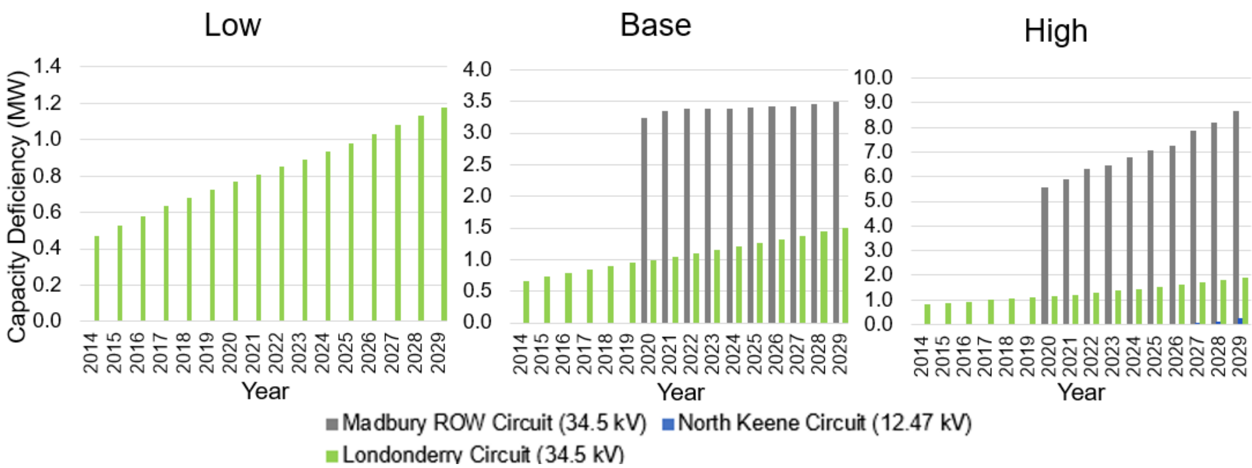
Figure 20. Non-Bulk Substation Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

Figure 21 presents selected distribution line capacity planning criteria violations for Eversource. Most distribution lines (circuits) typically have lower capacity ratings and serve fewer customers compared to bulk substations; hence, the magnitude of capacity deficiencies is lower than bulk substations, but are comparable to non-bulk substations.

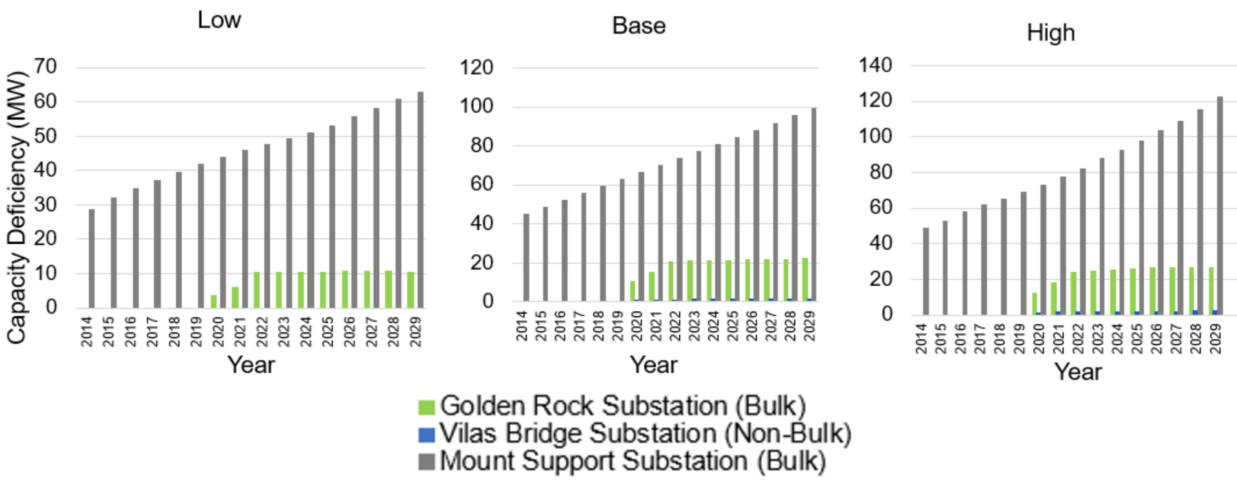
Figure 21. Circuit Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

Figure 22 presents selected capacity planning criteria violations for Liberty. Two of the three selected locations are historical projects completed between 2015 and 2020. Two of the three Liberty locations also have high capacity deficiencies; one of these, Mount Support, a historical project location, has very high deficiencies due to large number of violations addressed by the project. Due to high load growth projections assumed at the time the project was completed, future deficiencies increase at a higher rate compared to other locations.

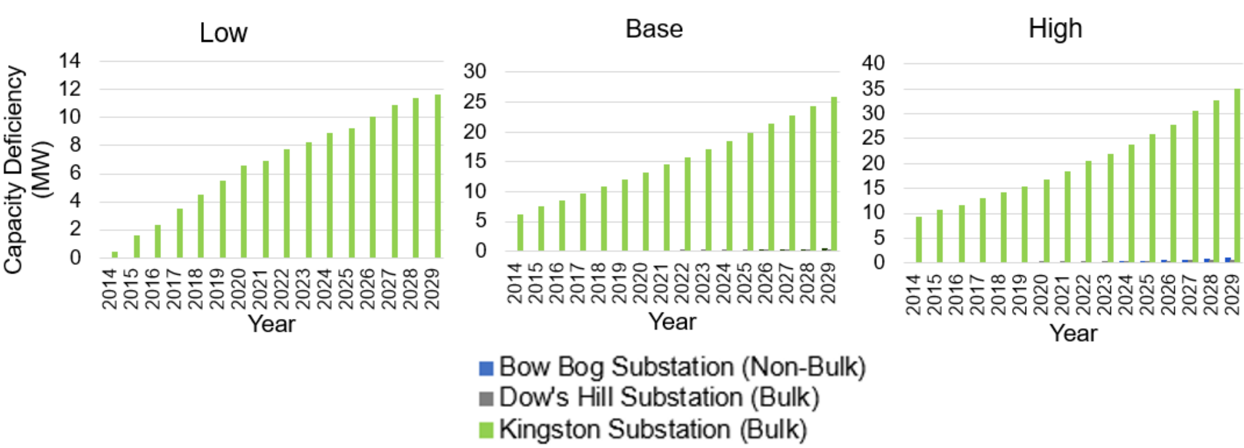
Figure 22. Selected Locations Capacity Deficiencies – Liberty



Source: Guidehouse, EDC data

Figure 23 presents selected locations' capacity planning criteria violations for Unitil. Kingston Substation, the one location with large capacity deficiencies, is a historical location with bulk substation capacity deficiencies. Few locations were available for selection in the forward-looking timeframe due to the prior completion of capacity projects and lack of significant load growth. The two forward-looking locations selected for in-depth review are non-bulk substations.

Figure 23. Selected Locations Capacity Deficiencies – Unitil



Source: Guidehouse, EDC data

3.0 Estimation of Investment Costs for Determining Avoidance Values (Step 2)

Step 2 of the study estimates the cost of capacity investments that potentially could be avoided for the 16 locations selected for in-depth review. The objective is to use these capital costs as one of the primary inputs to an economic model to then derive annual avoided costs over the 15-year study timeframe to inform the development of future

NEM tariffs.[35] The use of the capital costs to derive the avoided value is outlined in Section 4.0. The study determines the cost of traditional capacity investments for each of the 16 locations by:

- Developing avoidable investment capital cost estimates based on utility investments and historical spending for each selected location, including sub-transmission lines, substations, and distribution lines.
- Confirming capacity upgrade options and unit costs with the EDCs.
- Identifying potential capacity avoidance using scenarios (base, high, and low forecasts).
- Establishing cost avoidance associated with capacity avoidance opportunities by feeder type, voltage, location, length, and load diversity.

The analysis included derivation of historical spending versus forward-looking planned spend for traditional investments. However, only the capacity component of prior actual investments was used to determine theoretically avoidable costs for projects that have already been completed.[36]

3.1 Investment Costs Associated with Capacity Needs

This section identifies the cost of traditional investments required to address capacity deficiencies at the 16 locations derived in Section 2.3.2. It includes only those costs required to address capacity deficiencies, excluding any historical or forward-looking costs that may be needed to address reliability or performance issues. It also excludes the cost of minor investments such as capacitor banks, line transformers, and secondary line upgrades, unless those costs are included in major projects where minor upgrades are included in project totals, such as new distribution feeders that are constructed as part of a new substation or substation upgrade.

3.1.1 Derivation of Distribution Capacity Costs

Capacity costs for traditional investments that the EDCs would otherwise make to address capacity deficiencies, absent DG, or other load reduction measures were developed. The cost of traditional distribution capacity projects is used in Section 4.0 to determine the potential value of investment avoidances. Actual distribution capacity investments were reviewed and used for historical project locations, whereas forward-looking investments were estimated for study purposes.

The approach and assumptions applied to derive traditional capacity investments are summarized as follows:

[35] As noted previously, the analysis is intended to be theoretical and should not be construed as an NWS analysis for avoiding traditional capacity investments at specific locations.
[36] The derivation and application of costs associated with completed projects is intended as a counter-factual analysis to evaluate avoided costs based on a combination of actual and forecast costs of conventional capacity investments.

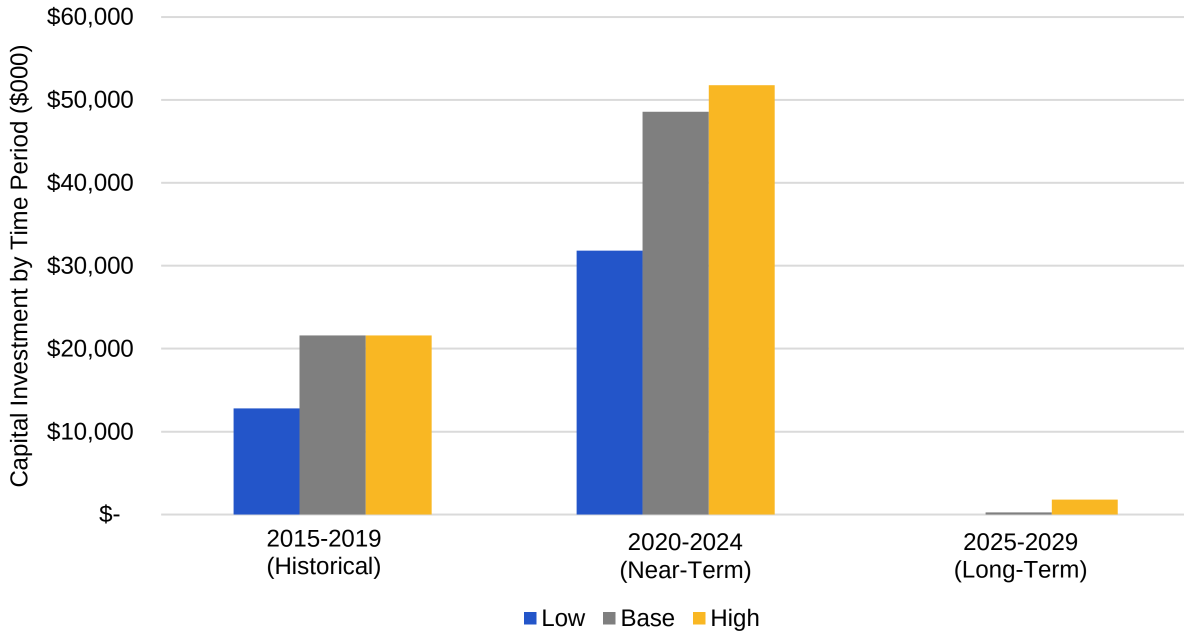
1. Capacity additions or upgrades are structured to address deficiencies over the entire study timeframe, up to year 2029
2. Mitigation options to address capacity deficiencies are based on EDC planning criteria that existed or exist at the date of the first year of capacity deficiency
3. Load growth is based on the growth projections that were prepared at the time the decision was made by an EDC for historical investments; for forward-looking investments, load growth projections are outlined in Section 2.2
4. The first year of the capacity investment is assumed to occur in the first year a capacity deficiency occurs. EDCs expect to complete some of the near-term projects after the first year a capacity deficiency is expected to occur.[37]
5. Only the capacity investment component of a project is included in project totals, some completed or proposed projects have a reliability cost component that is not reflected in the investment costs used in the LVDG analysis[38]
6. Actual EDC investment costs are used for historical project locations
7. EDC budget values are used to support derivation of forward-looking investments, where available
8. EDC per unit costs are applied for project locations where cost estimates are not available, typically for projects beyond the first 5 years

3.1.2 EDC Locational Capacity Investments

Figure 24 presents the composite capital investment value by EDC over the study timeframe for the 16 locations over three intervals: historical (2015-2019), near-term (2020–2024), and long-term (2025–2029). As prior sections note, the majority of capacity investments are needed in the near-term due to recent changes to planning criteria, with minimal investment needed thereafter to address capacity deficiencies. Further, long-term investments shown in Figure 24 are only required under the high load growth forecast.

[37] For example, several large capacity investments in the analysis are assumed to be undertaken in 2020 although the project may not yet actually be underway and may in fact not occur for several years. This is largely the result of Eversource's recently revised planning criteria.
[38] The EDCs provided data that indicated the amount of project costs associated with capacity versus reliability. The portion of the project cost needed for reliability was removed from total project costs.

Figure 24. Capital Investment Over Time for Selected Locations Across all EDCs



Note: 2015-2019 based on historical values (for capacity additions only)
Source: Guidehouse, EDC data

Table 12 summarizes the capital investment cost by location for the 16 selected locations. The investment costs by location range from a low of $200,000 for the East Northwood Substation in the Eversource service territory to a high of $14,300,000 for the Monadnock Substation in the Eversource service territory.

Table 12. Capital Investment by Location

EDC	Location	Traditional Investment Estimated Capital Costs for Capacity Additions
Eversource	Pemi Substation (Bulk)	$7,469,000
	Portsmouth Substation (Bulk)	$2,500,000
	South Milford Substation (Bulk)	$13,150,000
	Monadnock Substation (Bulk)	$14,300,000
	East Northwood Substation (Non-Bulk)	$200,000
	Rye Substation (Non-Bulk)	$3,000,000
	Bristol Substation (Non-Bulk)	$1,200,000
	Madbury ROW Circuit (34.5 kV)	$2,000,000
	North Keene Circuit (12.47 kV)	$1,530,000
	Londonderry Circuit (34.5 kV)	$615,000
Liberty	Vilas Bridge Substation (Non-Bulk)	$2,300,000
	Mount Support Substation (Bulk)	$7,608,000
	Golden Rock Substation (Bulk)	$6,400,000
Unitil	Bow Bog Substation (Non-Bulk)	$254,000
	Dow’s Hill Substation (Bulk)	$446,000
	Kingston Substation (Bulk)	$12,193,000

Source: Guidehouse, EDC data

When reviewing the capacity violations for the 16 selected locations, some capacity deficiencies are only triggered under certain load growth forecasts, while others are present in all load forecast scenarios. This is indicated per site in Table 13.

Table 13. Summary of Selected Locations Load Forecast Scenarios

EDC	Description	Low	Base	High
Eversource	Pemi Substation (Bulk)	✓	✓	✓
	Portsmouth Substation (Bulk)	✓	✓	✓
	South Milford Substation (Bulk)	✓	✓	✓
	Monadnock Substation (Bulk)		✓	✓
	East Northwood Substation (Non-Bulk)			✓
	Rye Substation (Non-Bulk)			✓
	Bristol Substation (Non-Bulk)	✓	✓	✓
	Madbury ROW Circuit (34.5 kV)		✓	✓
	North Keene Circuit (12.47 kV)			✓
	Londonderry Circuit (34.5 kV)	✓	✓	✓
Liberty	Vilas Bridge Substation (Non-Bulk)		✓	✓
	Mount Support Substation (Bulk)	✓	✓	✓
	Golden Rock Substation (Bulk)	✓	✓	✓
Unitil	Bow Bog Substation (Non-Bulk)		✓	✓
	Dow's Hill Substation (Bulk)		✓	✓
	Kingston Substation (Bulk)	✓	✓	✓
	Total	**8**	**13**	**16**

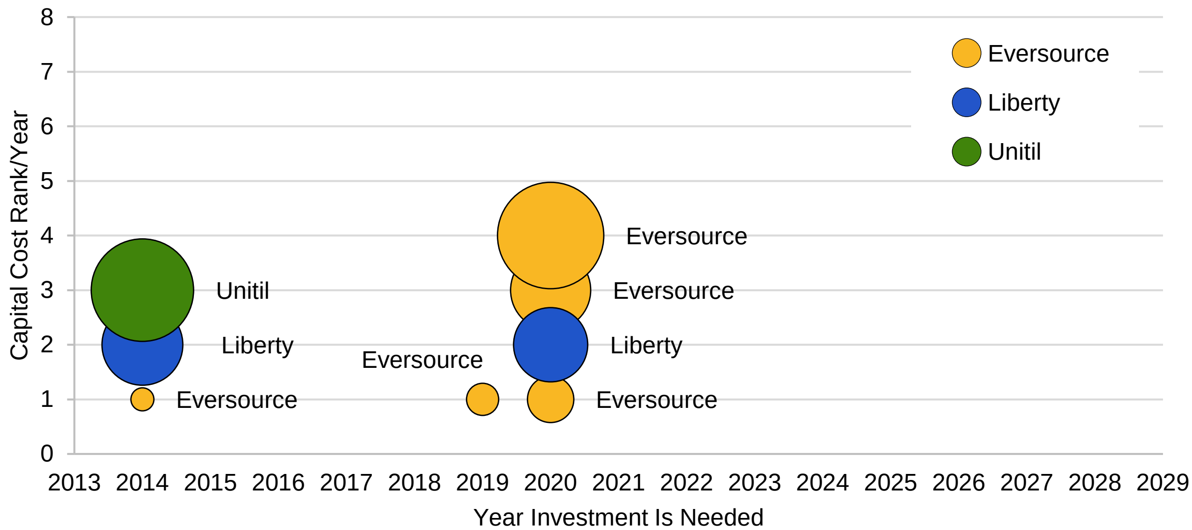
Source: Guidehouse, EDC data

The following section summarizes the capital investment cost for the three load forecast scenarios: low, base, and high.

3.2 Capital Cost Results by Load Forecast Scenario

Figures 25 through 27 present the capital costs of the selected locations by year of investment for each load growth forecast. In these figures, yellow represents an Eversource location, blue represents a Liberty location, and green represents a Unitil location. The size of the bubble equates to the amount of capital investment cost (see Table 12), i.e., larger bubble means higher capital cost. The locations are also ranked in each year by the amount of investment cost per location for that year with the highest investment cost in that year having the highest rank (i.e., highest bubble on the figure for that year). Figure 25 presents the low load forecast's capital costs by year of investment need for each of the EDCs. Figure 25 shows the eight locations of the selected 16 that would require an investment in the low load forecast scenario.

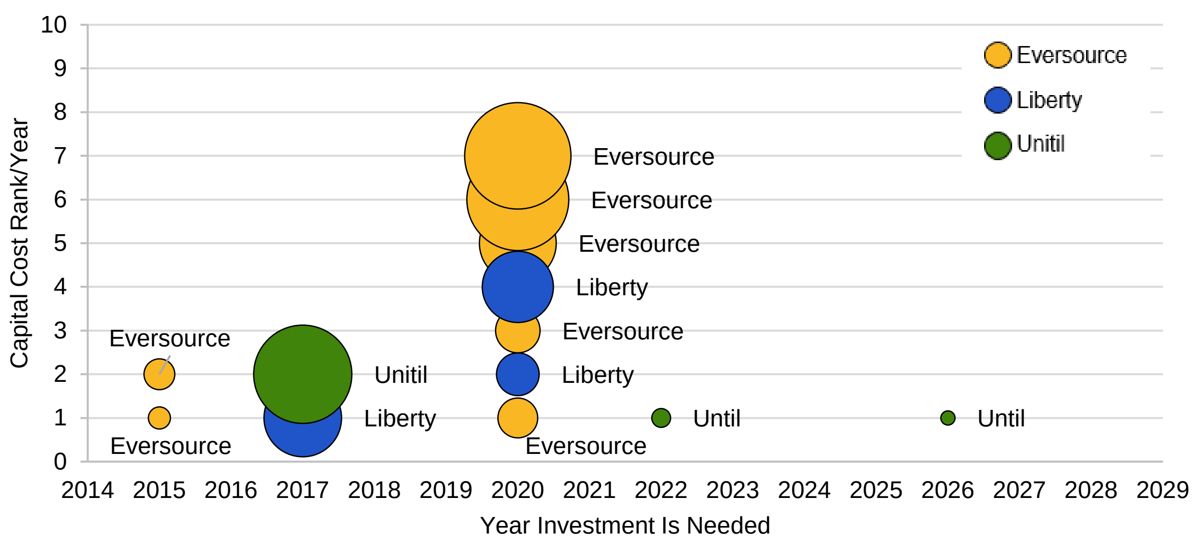
Figure 25. Low Load Forecast Capital Costs by Year of Investment Need



Source: Guidehouse, EDC data

Figure 26 shows results for the base load forecast's avoided costs by year of capital investment need for each of the EDCs. More location capital investments are required under the base load forecast scenario than the low load forecast scenario. Figure 26 includes 13 of the selected 16 locations.

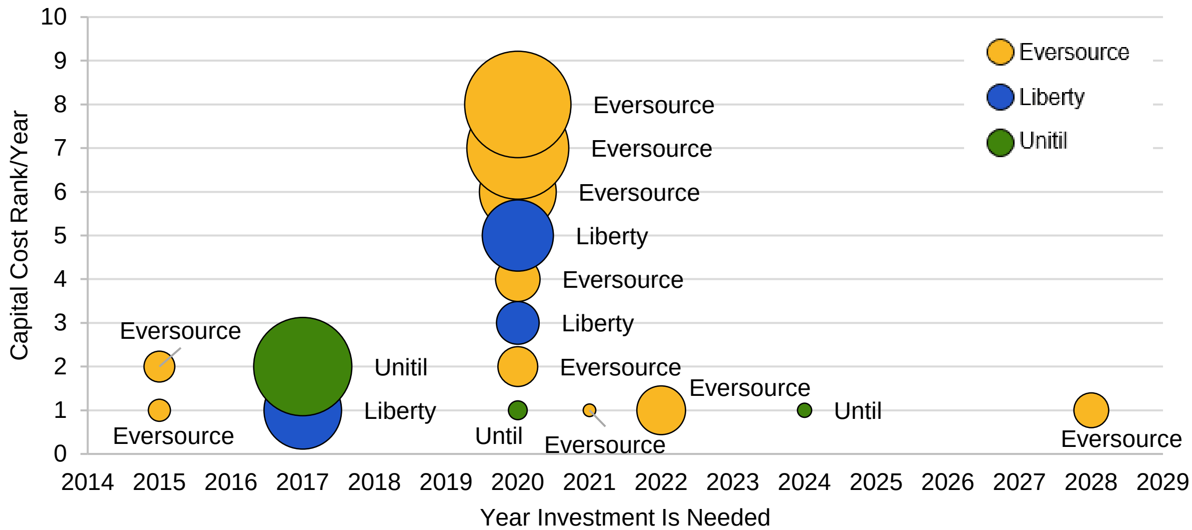
Figure 26. Base Load Forecast Capital Costs by Year of Investment Need



Source: Guidehouse, EDC data

Figure 27 presents the high load forecast's avoided costs by year of investment need for each of the EDCs. The high forecast includes all of the 16 selected locations and investments out to year 2028.

Figure 27. High Load Forecast Capital Costs by Year of Investment Need



Source: Guidehouse, EDC data

4.0 Economic Analysis and Mapping of DG Output Profiles with Distribution Capacity Needs (Step 3)

Step 3 includes an economic analysis to estimate values of investment avoidance at the 16 selected locations and the mapping of representative DG output profiles with the distribution capacity needs. The analysis to develop an economic value of avoiding investments starts with calculating the investment revenue requirement. The team annualizes this value to determine an annual total dollar value and uses the maximum demand reduction needed to avoid the investment in each year to determine an annual value per kW. Finally, to determine an indicative hourly value per kW per year, the team distributes the annual total value either for 2020 or for the first year of need if later than 2020 over the hours of need in that year. Sections 4.1 and 4.2 summarize the economic analysis.

The second part of Step 3 includes a comparison of hourly load profiles for all 16 locations and representative DG production profiles to illustrate the coincidence in terms of hours of the day between location-specific capacity deficits and DG production profiles. This is summarized in Sections 4.3.1 and 4.3.2. Section 4.3.3 includes a description of this methodology.

4.1 Annual Avoidance Benefits Estimation Methodology

Completing the economic analysis first requires development of an annualized value of local avoided costs. Based on an industry literature scan, the study identifies various methods to estimate the capacity avoidance benefits:

- Annualization of difference in net present value (NPV) of revenue requirement
- Real Economic Carrying Charge (RECC) methodologies

- Flat annualization of a capital cost to estimate the annual cost of that investment
- Stochastic methodologies[39]

Appendix C presents the four methodologies considered for forecasting the economic value of distribution capacity avoidance, including the pros and cons of each approach. As a result of this comparison, the team determined that the RECC methodology without a set deferral period, or Method C, is the most appropriate method of those considered to estimate the locational value of avoidance and can be used to inform future studies and NEM tariffs. Avoidance in all further references is defined as the yearly deferral of the estimated capital investment cost associated with capacity that is quantified from the year of the investment need through the end of the study period. The decision to use the RECC methodology was driven by the flexibility of the RECC methodology to be leveraged throughout the study period without assuming specific avoidance durations such as 5 or 10 years, as described above.

4.1.1 RECC Methodology Detailed Summary

The RECC method leads to the development of a RECC rate that yields the same present value of the investment revenue requirement when adjusted for inflation over the life of the asset. This is basically a reshaping of the costs to develop a stream of costs that increase with inflation. In other words, this is the amount of dollars in the first year the investment is needed that, when increased at a fixed rate of inflation every year, results in the same present value at the end of the life of the investment as the present value of the revenue requirements. The inputs to determine the RECC rate are the same as the inputs for developing the revenue requirement (Table 14).

[39] While the study considered stochastic methodologies, the scope of the study did not include a full stochastic analysis, so this approach was excluded from further study.

Table 14. Revenue Requirement and RECC Inputs

Input	Eversource[40]	Liberty (as of April 30, 2020)[41]	Unitil[42]
Long Term Debt Rate	4.11%	5.97%	7.15%
Equity Rate	9.67%	9.40%	9.50%
% Debt in Capital Structure	48.08%	50.00%	49.03%
% Equity in Capital Structure	51.92%	50%	50.97%
Return on Rate Base	8.70%	9.45%	10.15%
Nominal Discount Rate or After Tax WACC (%/year)	6.82%	7.69%	8.32%
Inflation Rate[43]	1.90%	1.90%	1.90%

Source: Guidehouse, EDC data

In addition to developing a stream of costs, the RECC value also reflects the value (including inflation) associated with avoiding an investment in any specific year and moving that investment to the next year. This method of developing the RECC rate was first established in the late 1970s.[44]

Key inputs to the RECC method to determine the annual avoidance value are the revenue requirement, inflation rate, weighted average cost of capital (WACC) for each EDC, and asset lifetime. The asset lifetime is assumed to be 30 years for all assets evaluated.

The specific equation used to calculate the RECC rate (%/year) is:

$$RECC\left(\frac{\%}{year}\right) = (WACC - inflation\,rate) * \left(\frac{(1+WACC)^{asset\,lifetime}}{(1+WACC)^{asset\,lifetime} - (1+inflation\,rate)^{asset\,lifetime}}\right)$$

Once the RECC rate is determined, the avoidance value for a single year is calculated using the equation below:

[40] Docket No. 18-177. Eversource Petition for Continuation of Reliability Enhancement Program. Purington and Goulding Technical Statement Attachment. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2018/18-177/INITIAL%20FILING%20-%20PETITION/18-177_2018-11-16_EVERSOURCE_ATT_TECH_STATEMENT_ALLEN_PURINGTON_GOULDING.PDF
[41] Docket No. DE 17-189. Petition for Approval of Battery Storage Program. Settlement of the Parties, Attachment 1. (November 19, 2018) Available at: https://puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2018-11-19_GSEC_ATT_SETTLEMENT.PDF This Study does not incorporate the updated values as a result of Order No. 26,377 (June 30, 2020), which approved Liberty's request for an increase in permanent rates. However, the project team reviewed the updated numbers and concluded that the changes had a de minimis impact on study results and did not change the study conclusions.
[42] Docket No. DE 19-043. Unitil 2019 Step Adjustment. Direct Testimony of Todd R. Diggins. Schedule TRD-1 2019. Available at: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-043/INITIAL%20FILING%20-%20PETITION/19-043_2019-02-28_UES_ATT_DTESTIMONY_DIGGINS.PDF
[43]Gross Domestic Product: Implicit Price Deflator https://fred.stlouisfed.org/data/GDPDEF.txt
[44] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). Electric cost allocation for a new era: A manual. Montpelier, VT: Regulatory Assistance Project.

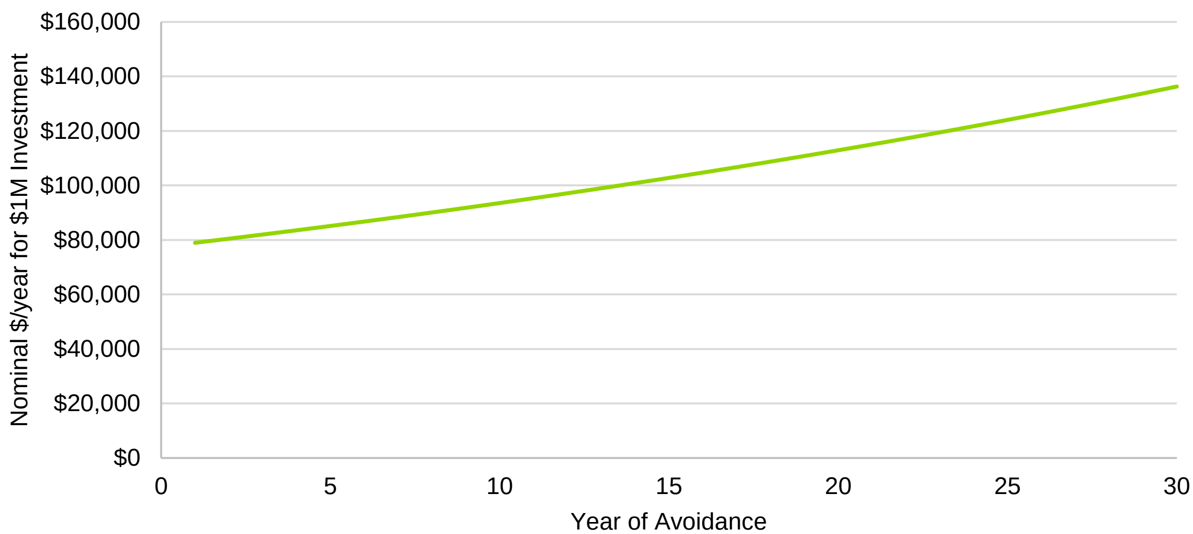
$$Single\ year\ avoidance\ benefit\ (\$) = Revenue\ Requirement * \frac{RECC}{(1 + inflation\ rate)}$$

The avoidance value in any given year can then be calculated as:

$$Avoidance\ benefit\ in\ year\ x\ (\$) = Single\ year\ avoidance\ benefit * (1 + infalation\ rate)^x$$

Figure 28 provides an example of the calculated RECC avoidance benefit for an investment of $1 million with a 30-year asset lifetime. The yearly avoidance benefit increases from approximately $80,000 up to close to $140,000 over the 30-year period. For this study, avoided costs per kW were only calculated to the end of the study period because capacity deficiency is unknown beyond the study period.

Figure 28. RECC Avoidance Value



Source: Guidehouse, EDC data

First, the RECC annual value was used to develop the yearly $/kW. As described in the next section, the RECC annual value is also used to develop the $/kW/hr value. The key input to the calculation of those values is the revenue requirement of the estimated traditional capacity investment (development of the estimate of capital cost associated with capacity is summarized in Section 3.0). Table 15 lists the revenue requirement for the 16 locations considered for in-depth review. The revenue requirement ranges from a low of $242,995 for the East Northwood Substation (Non-Bulk) in the Eversource service territory to a high of $17,374,146 for the Monadnock Substation (Bulk), also in the Eversource service territory.

Table 15. Revenue Requirement by Location

EDC	Location	Estimated Revenue Requirement for Traditional Investment Capacity Additions
Eversource	Pemi Substation (Bulk)	$9,074,650
	Portsmouth Substation (Bulk)	$3,037,438
	South Milford Substation (Bulk)	$15,976,924
	Monadnock Substation (Bulk)	$17,374,146
	East Northwood Substation (Non-Bulk)	$242,995
	Rye Substation (Non-Bulk)	$3,644,926
	Bristol Substation (Non-Bulk)	$1,457,970
	Madbury ROW Circuit (34.5 kV)	$2,429,950
	North Keene Circuit (12.47 kV)	$1,858,912
	Londonderry Circuit (34.5 kV)	$747,210
Liberty	Vilas Bridge Substation (Non-Bulk)	$2,715,803
	Mount Support Substation (Bulk)	$7,557,017
	Golden Rock Substation (Bulk)	$8,983,404
Unitil	Bow Bog Substation (Non-Bulk)	$299,375
	Dow's Hill Substation (Bulk)	$525,674
	Kingston Substation (Bulk)	$14,371,184

Source: Guidehouse, EDC data

4.1.2 Annual Avoidance Value Results

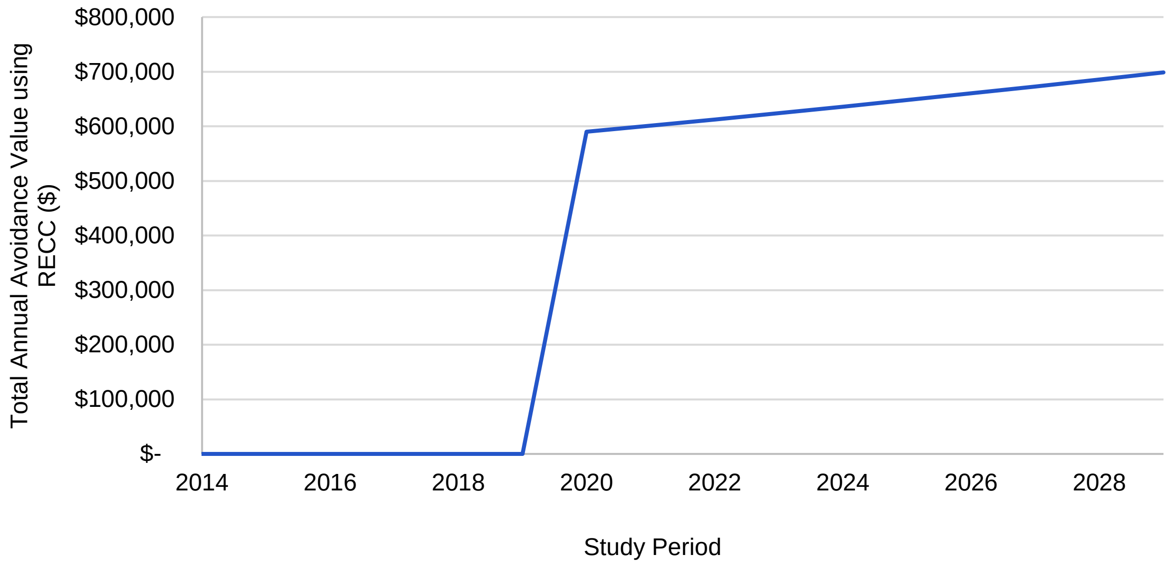
The calculation of the annual economic value from the revenue requirement is shown in detail for two example locations: Pemi Substation in the Eversource service territory and Dow's Hill Substation in the Unitil service territory. The results of the annual economic analysis for all locations are presented in tabular form following the two detailed examples. Additional graphical examples of annual value for avoidance of investment are found in Appendix D.

Example #1- Pemi Substation (Bulk) Yearly Economic Analysis (EDC: Eversource)

The RECC annual avoidance value begins in 2020, the first year of the capacity deficit (Figure 29).[45] The annual value is the same for all cases (low, base, and high) since the first year of the capacity deficit does not change due to load forecast scenario. The value increases from approximately $600,000 in year 2020 to close to $700,000 by 2029, the end of the study period.

[45] Note: this deficit is driven by a change in planning criteria.

Figure 29. Total Annual Avoidance Value – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

Once the annual dollar value is calculated using the RECC method, the next step is to calculate the yearly value for all three load growth scenarios on a $/kW basis. Table 16 provides examples of calculations for the Pemi Substation. Column (A) is the yearly value from the RECC analysis and is shown in Figure 29 as well. Columns (B) through (D) are the estimated maximum capacity deficit for Pemi from 2020 through to 2029, the first year of need through the end of the study period. The final three columns, (E) through (G) are the calculated local avoided annual value for the three load forecast scenarios. The scenario with the lowest capacity deficit, the Low Case for the Pemi example, results in the highest value per kW reduced.

Table 16. Pemi Substation (Bulk) Yearly Economic Analysis- Example Calculations

Year with Capacity Deficiency	Yearly Value from RECC Analysis ($)	Estimated Capacity Deficit (MW)			Local Avoided Annual Value ($/kW)		
		Low	Base	High	Low	Base	High
Column	(A)	(B)	(C)	(D)	(E)=(A)/(B)	(F)=(A)/(C)	(G)=(A)/(D)
2020	$589,811	6.07	8.3	9.77	$97	$71	$60
2021	$601,017	6.16	8.5	10.07	$98	$71	$60
2022	$612,436	6.21	8.6	10.47	$99	$71	$58
2023	$624,073	6.25	8.7	10.68	$100	$72	$58
2024	$635,930	6.29	8.8	11.01	$101	$72	$58
2025	$648,013	6.35	8.9	11.31	$102	$73	$57
2026	$660,325	6.42	9.0	11.54	$103	$73	$57
2027	$672,871	6.50	9.1	12.07	$104	$74	$56
2028	$685,656	6.61	9.3	12.42	$104	$74	$55
2029	$698,683	6.65	9.44	12.88	$105	$74	$54

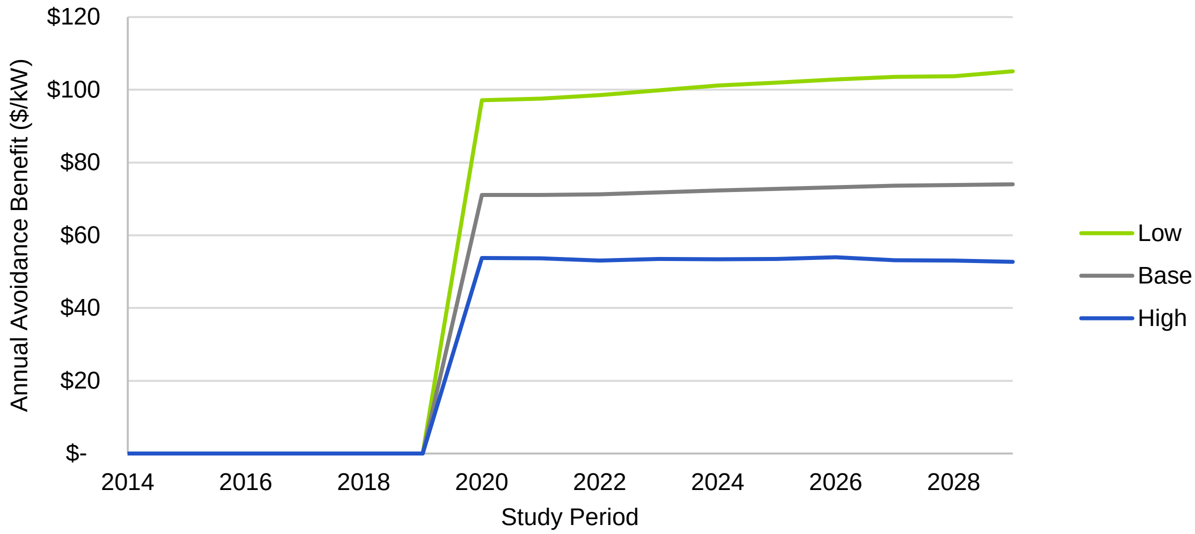
Table 16. Pemi Substation (Bulk) Yearly Economic Analysis- Example Calculations

Year with Capacity Deficiency	Yearly Value from RECC Analysis ($)	Estimated Capacity Deficit (MW)			Local Avoided Annual Value ($/kW)		
		Low	Base	High	Low	Base	High
Column	(A)	(B)	(C)	(D)	(E)=(A)/(B)	(F)=(A)/(C)	(G)=(A)/(D)
2030	$711,958	Because the values for capacity deficiency are unknown past the end of the study period, a $/kW value cannot be calculated past the end of the study period even though there is still avoided annual value. The avoided annual value continues until an investment is made. In this example, that is assumed to be at least 30 years or the lifetime of the asset. This study examines avoided cost values through the end of the study period; 2029.					
2031	$725,485						
2032	$739,270						
2033	$753,316						
2034	$767,629						
2035	$782,214						
2036	$797,076						
2037	$812,220						
2038	$827,652						
2039	$843,378						
2040	$859,402						
2041	$875,730						
2042	$892,369						
2043	$909,324						
2044	$926,602						
2045	$944,207						
2046	$962,147						
2047	$980,428						
2048	$999,056						
2049	$1,018,038						

Source: Guidehouse, EDC data

Columns (E) through (G) are also shown in Figure 30.

Figure 30. Annual Avoidance Benefit – Pemi Substation (Bulk)

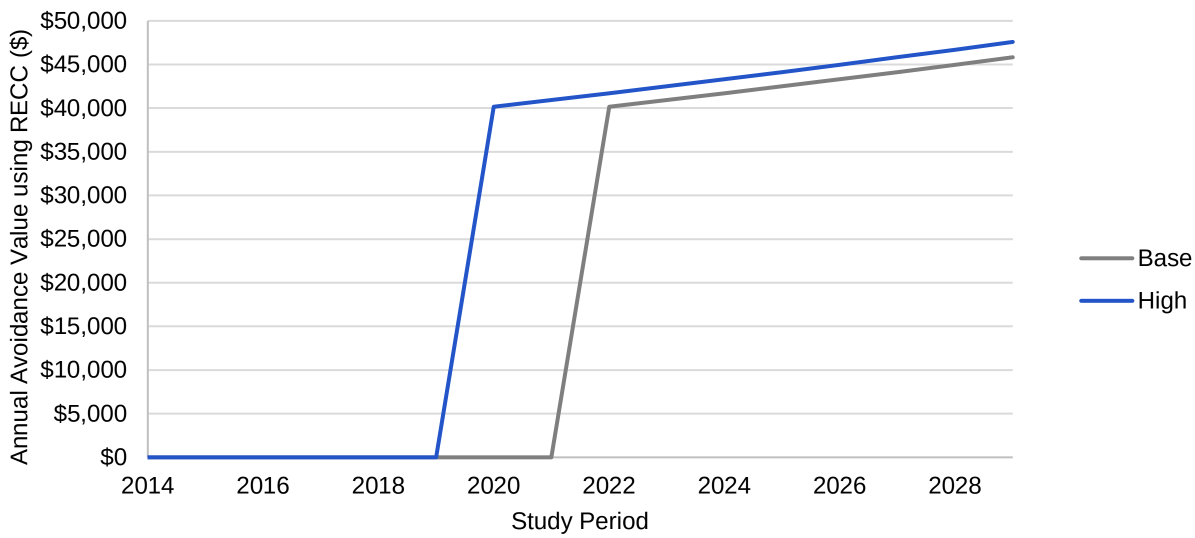


Source: Guidehouse, EDC data

Example #2- Dow's Hill Substation (Bulk) Yearly Economic Analysis (EDC: Unitil)

Dow's Hill Substation is used as the second example since the first year of capacity deficit varies between the load forecast scenarios. For the High Case, the annual avoidance value begins in 2020 and for the Base Case it begins in 2022 (Figure 31). These are the first year of capacity deficit for each load forecast scenario.

Figure 31. Total Annual Avoidance Value – Dow's Hill Substation (Bulk)

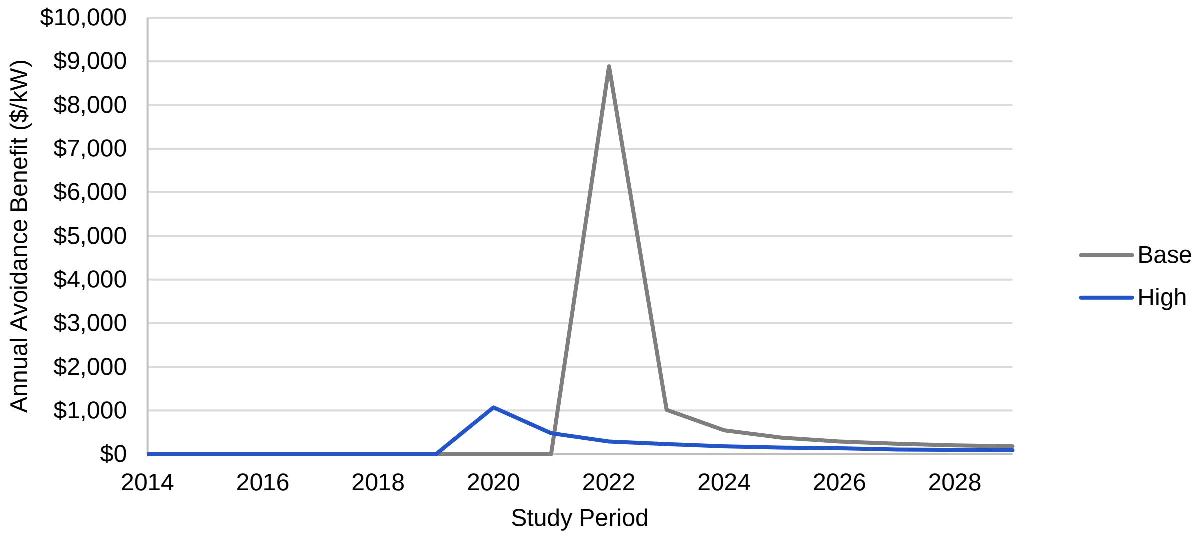


Source: Guidehouse, EDC data

The local annual avoidance benefit for Dow's Hill can be determined (Figure 32) using the same process as the Pemi Substation (Table 16). The first-year avoidance value for

Dow's Hill for the Base Case for 2022 is high since the capacity deficit is less than 5 kW. As the capacity deficit increases, the annual avoidance value per kW decreases drastically. The difference between the base and High Case is pronounced for Dow's Hill for two reasons. First, the High Case leads to a capacity deficit in an earlier year than the Base Case. Second, the high forecast leads to a much flatter and larger capacity deficit over time compared to the Base Case, which leads to a more consistent $/kW per year value.

Figure 32. Annual Avoidance Value– Dow's Hill Substation (Bulk)



Source: Guidehouse, EDC data

For locations such as Pemi where the load forecast does not influence the investment year, the yearly value from the RECC analysis provides the same annual value for each load forecast. The load forecast does not change the investment needed or the cost of that investment. Given this, the forecast with the lowest capacity deficiency results in the highest $/kW value in that year. For locations where the load forecast does change the initial year of capacity deficit, such as Dow's Hill, the case with an earlier capacity deficit may lead to a non-zero annual avoidance value that is higher than cases with lower load forecasts.

Table 17 shows the results of the total annual avoidance value using the RECC method for all 16 locations and all load forecast scenarios. Table 18 shows the results of the annual avoidance value per kW for all 16 locations and all load forecast scenarios.

Table 17. Total Annual Avoidance Value by Location and Load Forecast

EDC	Site	Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Eversource	Pemi Substation (Bulk)	All							$589,811	$601,017	$612,436	$624,073	$635,930	$648,013	$660,325	$672,871	$685,656	$698,683
	Portsmouth Substation (Bulk)	All							$197,420	$201,171	$204,993	$208,888	$212,856	$216,901	$221,022	$225,221	$229,500	$233,861
	South Milford Substation (Bulk)	All							$1,038,427	$1,058,157	$1,078,262	$1,098,749	$1,119,625	$1,140,898	$1,162,575	$1,184,664	$1,207,173	$1,230,109
	Monadnock Substation (Bulk)	Base & High							$1,129,240	$1,150,695	$1,172,559	$1,194,837	$1,217,539	$1,240,672	$1,264,245	$1,288,266	$1,312,743	$1,337,685
	East Northwood Substation (Non-Bulk)	High								$15,794	$16,094	$16,399	$16,711	$17,029	$17,352	$17,682	$18,018	$18,360
	Rye Substation (Non-Bulk)	High									$236,903	$241,405	$245,991	$250,665	$255,428	$260,281	$265,226	$270,266
	North Keen Circuit (34.5kV)	High														$120,821	$123,116	$125,456
	Bristol Substation (Non-Bulk)	All		$94,761	$96,562	$98,397	$100,266	$102,171	$104,112	$106,090	$108,106	$110,160	$112,253	$114,386	$116,559	$118,774	$121,031	$123,330
	Madbury ROW Circuit (34.5 kV)	Base & High							$157,936	$160,936	$163,994	$167,110	$170,285	$173,521	$176,817	$180,177	$183,600	$187,089
	Londonderry Circuit (34.5 kV)	All		$48,565	$49,488	$50,428	$51,386	$52,363	$53,358	$54,371	$55,404	$56,457	$57,530	$58,623	$59,737	$60,872	$62,028	$63,207
Liberty	Golden Rock Substation (Bulk)	All							$642,568	$654,777	$667,217	$679,894	$692,812	$705,976	$719,389	$733,058	$746,986	$761,179
	Vilas Bridge Substation (Non-Bulk)	Base & High							$194,257	$197,948	$201,709	$205,541	$209,446	$213,426	$217,481	$221,613	$225,824	$230,114
	Mount Support Substation (Bulk)	All				$540,541	$550,811	$561,276	$571,941	$582,807	$593,881	$605,165	$616,663	$628,379	$640,318	$652,485	$664,882	$677,515
Unitil	Bow Bog Substation (Non-Bulk)	Base													$22,879	$23,314	$23,757	$24,208
		High											$22,879	$23,314	$23,757	$24,208	$24,668	$25,137
	Dow's Hill Substation (Bulk)	Base									$40,174	$40,937	$41,715	$42,508	$43,315	$44,138	$44,977	$45,831
		High							$40,174	$40,937	$41,715	$42,508	$43,315	$44,138	$44,977	$45,831	$46,702	$47,589
	Kingston Substation (Bulk)	All				$1,098,295	$1,119,163	$1,140,427	$1,162,095	$1,184,175	$1,206,674	$1,229,601	$1,252,963	$1,276,769	$1,301,028	$1,325,747	$1,350,937	$1,376,604

Source: Guidehouse, EDC data

Table 18. Annual Avoidance Value per kW by Location and Load Forecast

EDC	Location	Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Eversource	Pemi Substation (Bulk)	Low							$97	$98	$99	$100	$101	$102	$103	$104	$104	$105
		Base							$71	$71	$71	$72	$72	$73	$73	$74	$74	$74
		High							$60	$60	$58	$58	$58	$57	$57	$56	$55	$54
	Portsmouth Substation (Bulk)	Low							$25	$20	$18	$16	$15	$15	$16	$16	$16	$17
		Base							$16	$13	$12	$12	$11	$11	$11	$11	$12	$12
		High							$13	$11	$10	$9	$9	$9	$9	$9	$9	$9
	South Milford Substation (Bulk)	Low							$55	$49	$50	$51	$52	$53	$54	$55	$56	$57
		Base							$44	$40	$40	$41	$41	$42	$43	$43	$44	$44
		High							$39	$35	$34	$35	$34	$34	$35	$34	$34	$34
	Monadnock Substation (Bulk)	Base							$730	$639	$584	$552	$528	$499	$476	$455	$430	$407
		High							$288	$262	$233	$223	$207	$195	$188	$171	$162	$152
	East Northwood Substation (Non-Bulk)	High								$260	$105	$79	$57	$46	$41	$32	$28	$25
	Rye Substation (Non-Bulk)	High									$3,641	$2,168	$1,346	$1,027	$870	$653	$570	$493
	North Keen Circuit (34.5kV)	High														$860,465	$1,128	$511
	Bristol Substation (Non-Bulk)	Low						$1,187	$550	$387	$303	$248	$209	$181	$159	$142	$128	$120
		Base		$315	$218	$167	$144	$126	$113	$102	$93	$86	$80	$75	$71	$67	$64	$61
		High		$126	$107	$93	$85	$79	$74	$67	$60	$56	$52	$49	$46	$42	$40	$38
	Madbury ROW Circuit (34.5 kV)	Base							$49	$48	$49	$49	$50	$51	$52	$53	$53	$54
		High							$29	$28	$26	$26	$25	$25	$24	$23	$22	$22
	Londonderry Circuit (34.5 kV)	Low		$92	$85	$79	$76	$72	$69	$67	$65	$63	$61	$60	$58	$56	$55	$54
		Base		$68	$64	$60	$58	$56	$54	$52	$51	$49	$48	$47	$46	$44	$43	$42
		High		$58	$54	$52	$50	$49	$47	$45	$43	$42	$40	$39	$38	$36	$35	$34
Liberty	Golden Rock Substation (Bulk)	Low							$185	$107	$64	$65	$66	$67	$68	$69	$70	$72
		Base							$63	$43	$32	$33	$33	$33	$33	$34	$34	$34
		High							$53	$36	$28	$28	$28	$27	$27	$28	$28	$29
	Vilas Bridge Substation (Non-Bulk)	Base							$180	$179	$178	$176	$175	$175	$174	$174	$174	$174
		High							$140	$136	$131	$127	$123	$119	$115	$111	$108	$102
	Mount Support Substation (Bulk)	Low				$18	$17	$16	$15	$15	$15	$14	$14	$14	$14	$13	$13	$13
		Base				$11	$11	$11	$10	$10	$10	$10	$9	$9	$9	$9	$9	$9
		High				$11	$10	$10	$10	$9	$9	$9	$8	$8	$8	$8	$7	$7
Unitil	Bow Bog Substation (Non-Bulk)	Base													$291	$124	$80	$59
		High											$179	$87	$59	$43	$34	$28
	Dow's Hill Substation (Bulk)	Base									$8,888	$1,017	$549	$381	$294	$241	$206	$180
		High							$1,072	$483	$289	$231	$183	$152	$133	$111	$100	$90
	Kingston Substation (Bulk)	Low				$316	$251	$209	$178	$172	$157	$150	$142	$138	$130	$122	$119	$119
		Base				$114	$104	$96	$89	$82	$77	$72	$68	$64	$61	$58	$56	$54
		High				$85	$79	$74	$70	$65	$59	$56	$53	$49	$47	$43	$41	$39

Source: Guidehouse, EDC data

4.2 Hourly Avoidance Value Estimation Methodology

After calculating the annual avoidance value, the next step is to develop an indicative value of avoidance value for each hour. This step also leverages the yearly total annual avoidance value from the RECC analysis. The year of annual value used is either 2020 or the first year of the capacity deficit if that is after 2020. Therefore, the hourly value demonstrated here is not based on the highest or average annual value, but for many cases it is based on the lowest value when the year of investment need is 2020. However, the capacity deficiency is also the lowest for many of the cases since it is in the earlier year of need.

These $/kW/hr may be lower for later years if the capacity deficiency and number of hours of need increase at a rate higher than the rate that the annual value is increasing (which is the inflation rate of 1.9%). Even though all of the annual growth rates are lower than 1.9%, since these annual growth rates are applied to the entire load and not just the capacity deficiency (defined as the difference between the growing load and a fixed capacity threshold), the capacity deficiency can increase at rates greater than the load growth rates. The analytical method used to develop this indicative value is presented for two examples, the Pemi Substation and the Portsmouth Substation, both in the Eversource service territory. Appendix D provides three additional examples.

4.2.1 Examples of Analytical Approach to Calculate Hourly Value

Example #1- Pemi Substation (Bulk) – Hourly Analysis for 2020 (EDC: Eversource)

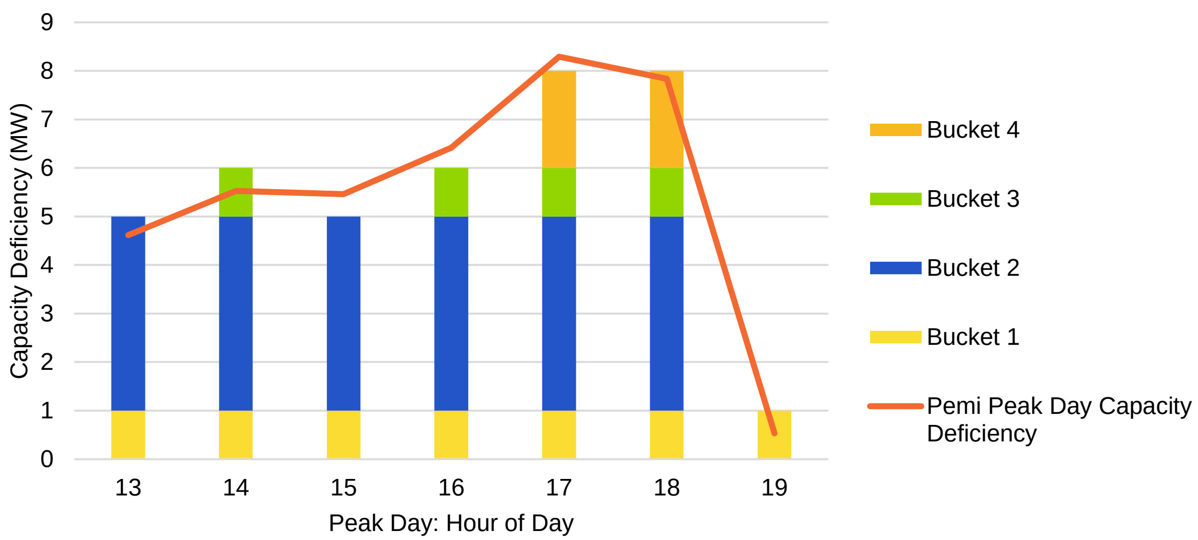
To simplify the explanation of the analytical process, the results that follow are for the peak day for the Pemi Substation. A three-step methodology was developed to assign an avoidance value to each hour. The first step is outlined as follows:

- **Step 1:** Segment peak day load excess into load capacity deficiency buckets
  - Round hourly capacity deficiency to nearest MW to generalize capacity deficiency load curve
  - Rank all hours with capacity deficiency from lowest capacity deficiency to highest capacity deficiency. For example, hour 19 has the lowest capacity deficiency, hours 13 and 15 have the second lowest capacity, hours 14 and 16 have the third lowest capacity deficiency, and hours 17 and 18 have the highest capacity deficiency.
  - Determine the capacity deficiency needs. This defines the number of buckets. For example, there are four levels of capacity deficiency needs for Pemi on the peak day: 1 MW (hour 19), 5 MW (hours 13 and 15), 6 MW (hours 14 and 16), and 8 MW (hours 17 and 18).
  - The first bucket is the heights of the lowest capacity deficiency need. This is 1 MW for hour 19.
  - The difference in capacity deficiency between each unique capacity deficiency level defines the height of the subsequent bucket. For example, the height of the second bucket is 5 MW minus 1 MW or 4 MW. This process is continued until all levels are met.

Based on the process outlined in the first step, four load buckets are required for Pemi's peak day to go from lowest capacity deficiency to highest capacity deficiency (see Figure 33).

- Bucket 1 height is 1 MW
- Bucket 2 height is 4 MW
- Bucket 3 height is 1 MW
- Bucket 4 height is 2 MW

Figure 33. Marginal Load Buckets (MW) – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

The second step calculates the weight of each hour. Hours with more capacity deficiency have higher weights.

- **Step 2:** Determine a total relative weight for each hour
  - Weight for each bucket in each hour equals load excess per bucket per hour divided by total MWh of excess load in that bucket across all hours.
  - Weight for each bucket is the height of the bucket divided by the sum of the heights of all buckets.
  - Total relative weight is the sum product of the bucket hourly weight and weight for each bucket. Results of this step are shown in Table 19.

Table 19. Hour of Day Weighting Example Calculation – Pemi Substation (Bulk)

Relative Weight by Hour of Day ↓	Bucket 1	Bucket 2	Bucket 3	Bucket 4	Total Relative Weight
13	14%	17%	0%	0%	10%
14	14%	17%	25%	0%	13%
15	14%	17%	0%	0%	10%
16	14%	17%	25%	0%	13%

Table 19. Hour of Day Weighting Example Calculation – Pemi Substation (Bulk)

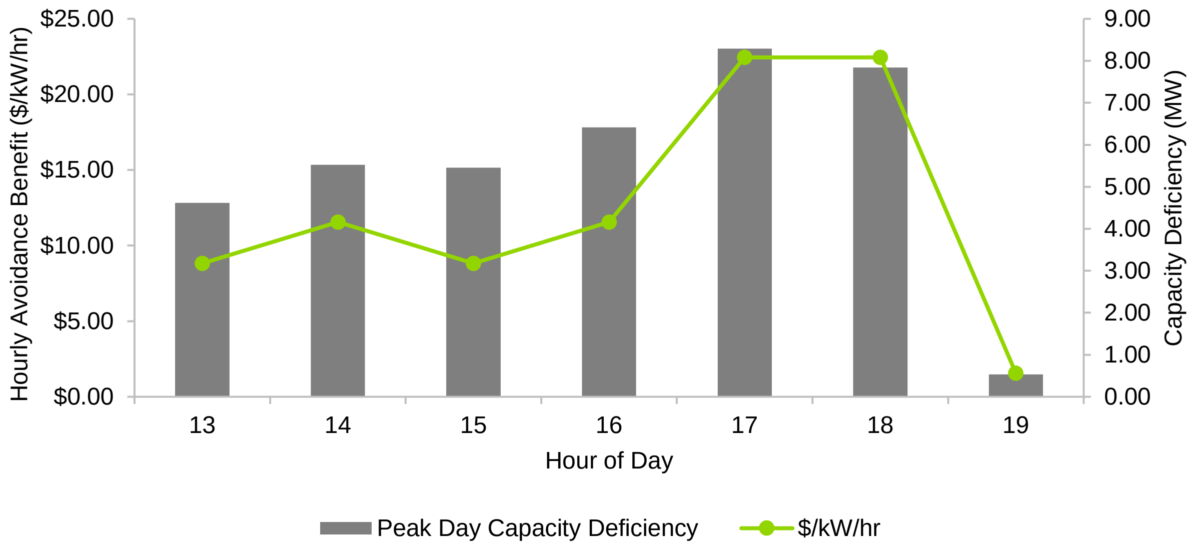
Relative Weight by Hour of Day ↓	Bucket 1	Bucket 2	Bucket 3	Bucket 4	Total Relative Weight
17	14%	17%	25%	50%	26%
18	14%	17%	25%	50%	26%
19	14%	0%	0%	0%	2%
Weight Across Buckets	13%	50%	13%	25%	100%

Source: Guidehouse, EDC data

The third step uses the total annual avoidance value ($) to calculate the hourly avoidance value.

- **Step 3**: Solve for the $/kW value that gets multiplied by the total relative weight such that the $/kW/hr for each hour times the amount of kW capacity deficit in each hour is equal to the total annual avoidance value for 2020. The results of Step 3 are presented in Figure 34.

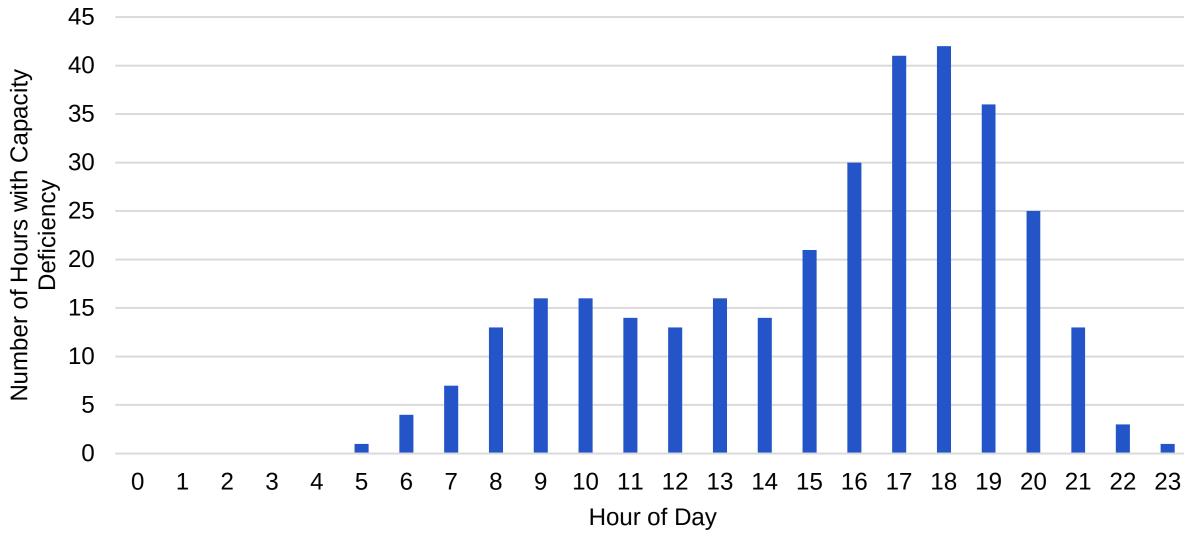
Figure 34. Hourly Avoidance Value and Capacity Deficiency – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

While the results for the peak day provide a simple example, to accurately represent the $/kW/hr, all hours of the year when there is a capacity deficiency need to be considered in the analysis. Figure 35 presents the number of times there is a capacity deficiency for each hour. As reflected in the figure, capacity deficiency frequently occurs during hours 16 through 20. However, there are some instances of capacity deficiency for hours between hour 5 and hour 23.

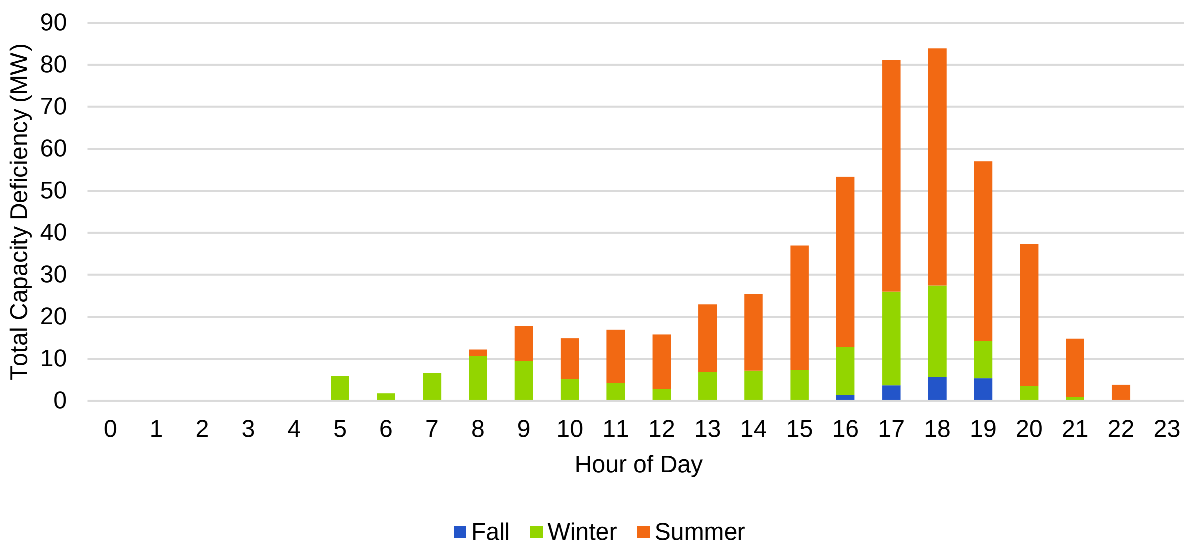
Figure 35. Number of Hours with Capacity Deficiency – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

Figure 36 presents the seasonal distribution of total capacity deficits at Pemi for 2020 for each hour of the day. Winter is defined as November through February, spring is March through May, summer is June through September, and fall is October. The majority of capacity deficits occur in the summer and winter periods at Pemi. There are no capacity deficits that occur in the spring period and few that occur in the fall.

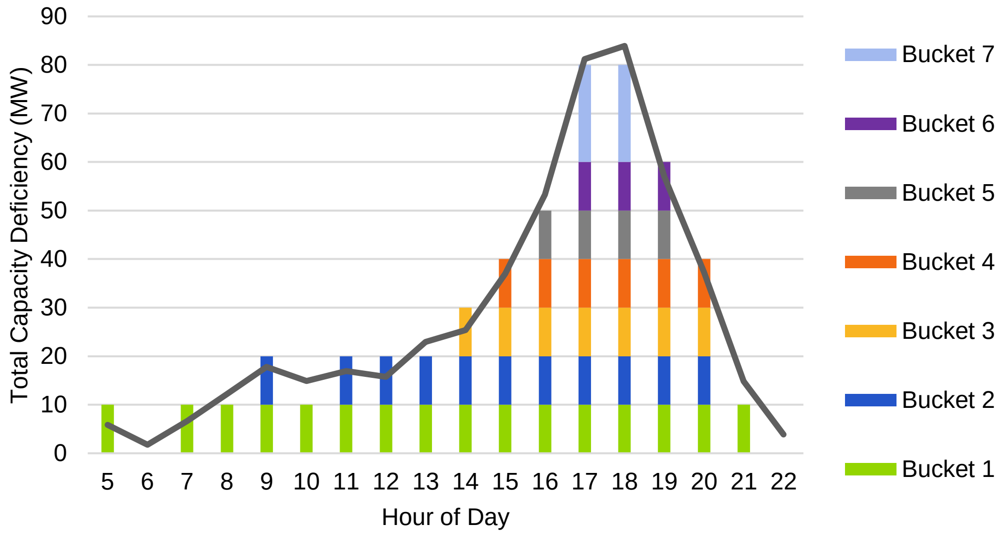
Figure 36. Seasonal Deficit Analysis – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

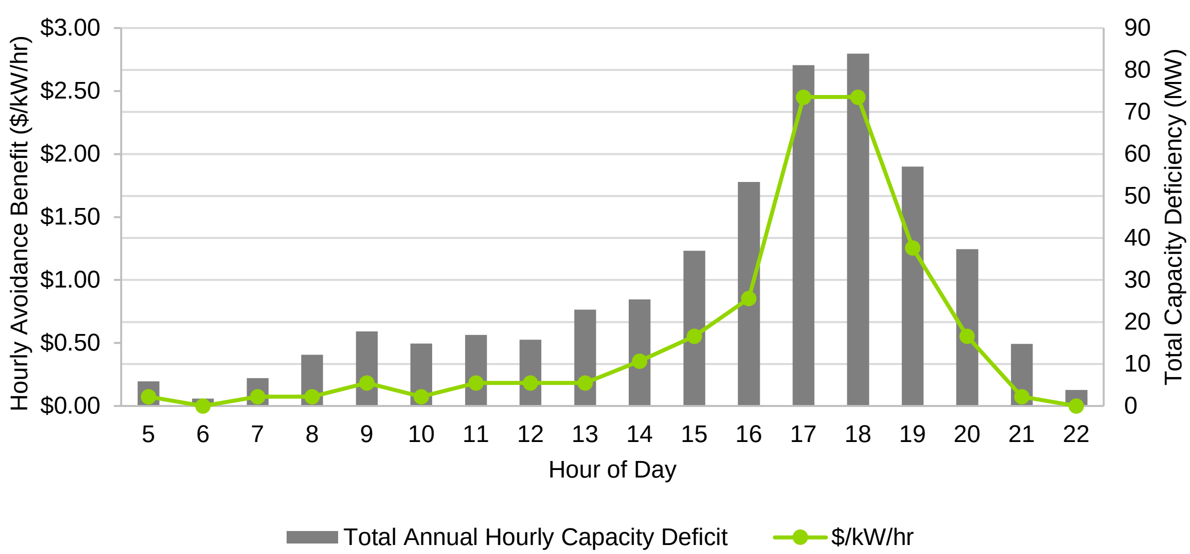
The same three step methodology used for the Pemi peak day can be used to assign a value given the total capacity deficit per hour over a whole year. Figure 37 shows the seven buckets needed to generalize the annual capacity deficit curve. Figure 38 shows the total annual capacity deficit and the $/kW/hr considering all hours of the year. Similar to the peak day analysis, the sum over all hours equals the annual avoidance value. The $/kW/hr during the peak time period of hours 17 and 18 is close to $23 for the peak day, but drops to about $2.50 when all hours of the year are considered.

Figure 37. Marginal Load Buckets (MW) – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

Figure 38. Pemi Hourly Analysis for All Hours of Year

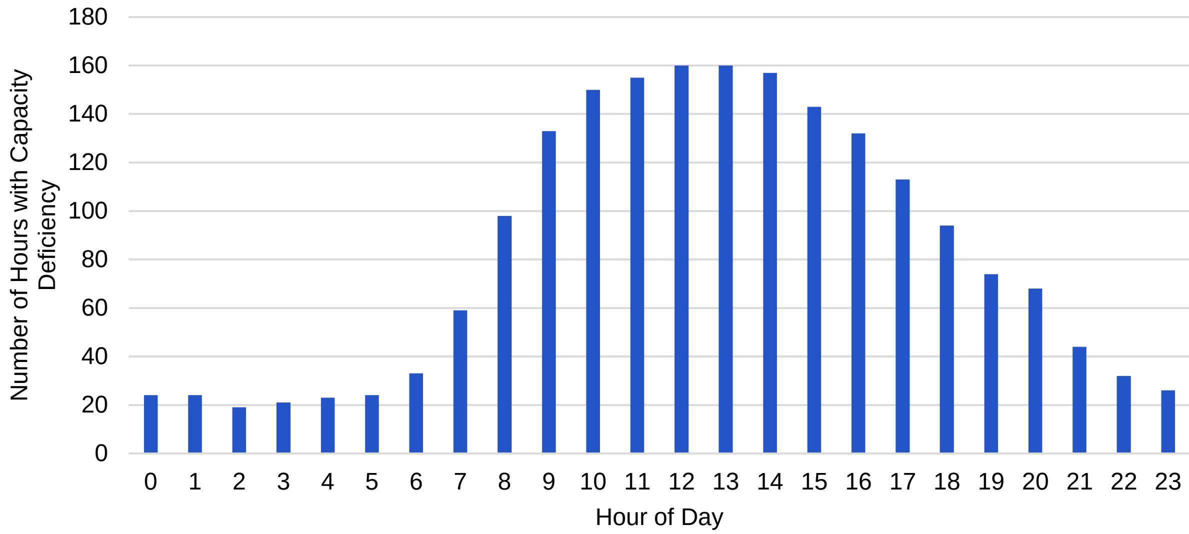


Source: Guidehouse, EDC data

Example #2- Hourly Local Value Calculation for Portsmouth Substation

This same annual analysis is repeated for Portsmouth, which had at least 19 hours of capacity deficiency for each hour of the day when considering all hours across an entire year (Figure 39). In contrast with the Pemi Substation, which had peaks in the afternoon and early evening, the majority of the hours with capacity deficiency at Portsmouth are for hours 12 and 13.

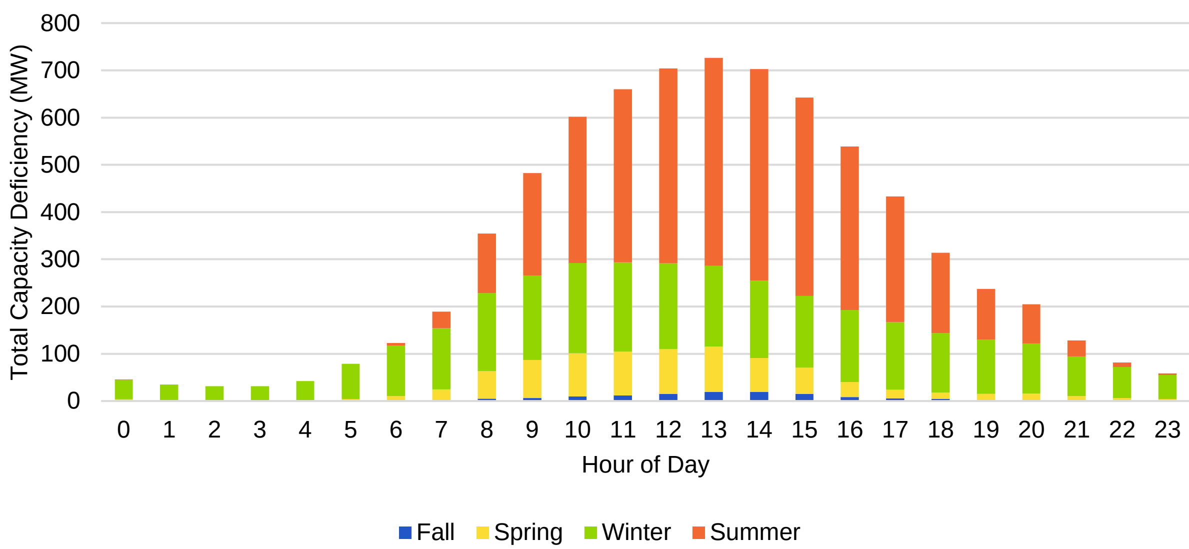
Figure 39. Number of Hours with Capacity Deficiency – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

Similar to the Pemi Substation, the majority of the capacity deficit occurred in the summer and winter periods, with some in the spring and fall periods as well (Figure 40).

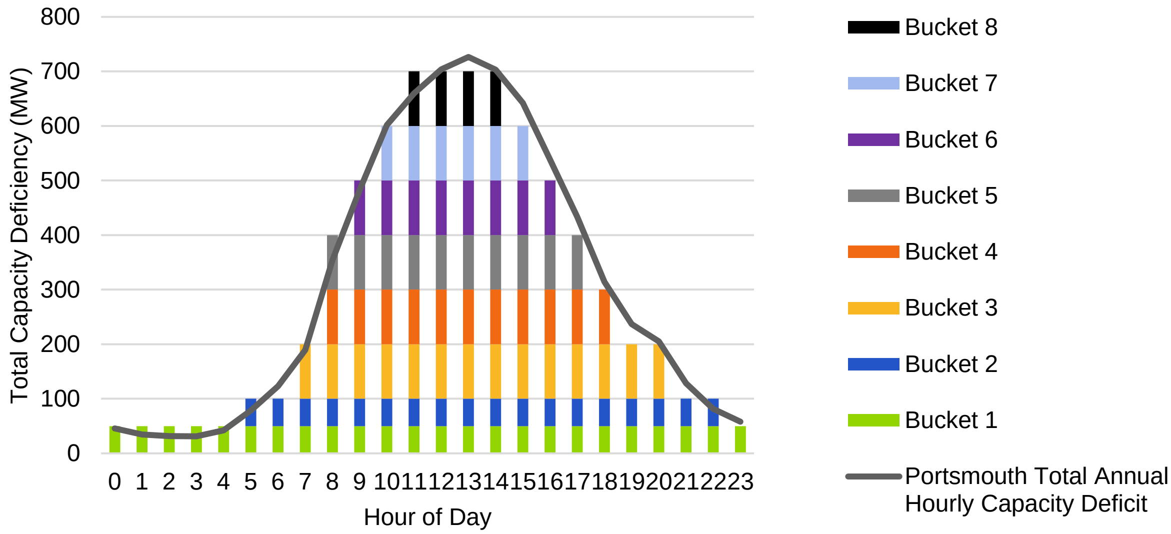
Figure 40. Seasonal Deficit Analysis – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

Due to the capacity deficiency variation by hour, Portsmouth required eight capacity deficiency buckets over all hours to generalize the yearly annual hourly capacity deficit (Figure 41).

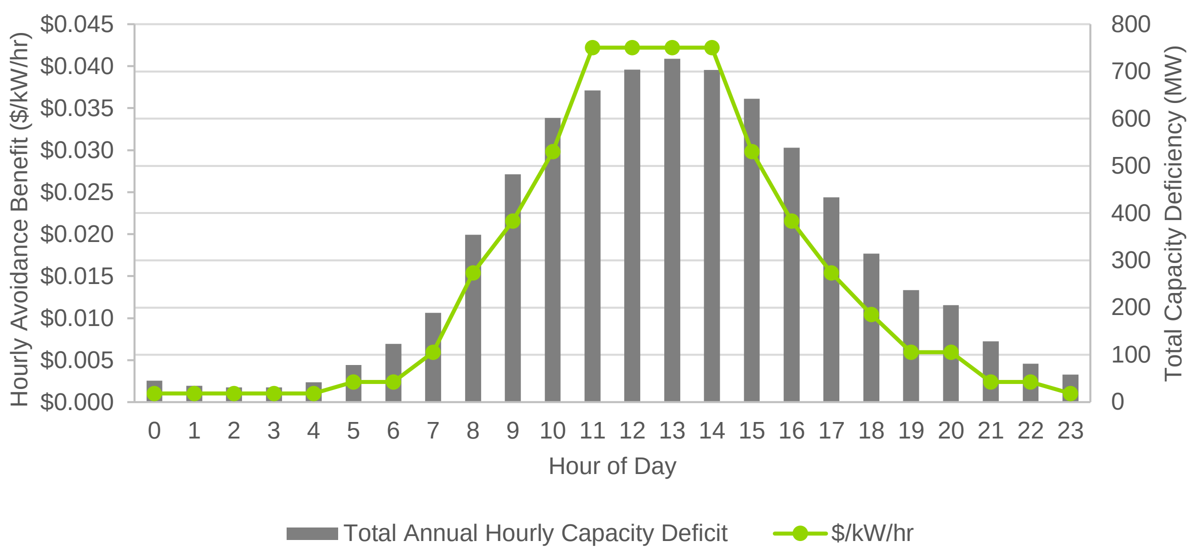
Figure 41. Marginal Load Buckets (MW) – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

The hourly value is small per kW, as Figure 42 shows.

Figure 42. Portsmouth Hourly Analysis for All Hours of the Year



Source: Guidehouse, EDC data

4.2.2 Hourly Avoided Cost Analysis Summary and Results

The 16 locations considered for detailed review in this study provide different outputs for hourly value per kilowatt per hour. Table 20 summarizes the results for all 16 locations and provides a rank of the value.[46] The maximum hourly value ranges from $0.04/kW/hr (for Mount Support and Portsmouth substations) up to $4,483/kW/hr (for the Dow's Hill Substation). Overall, the study found that the largest factor in determining the hourly value is the total annual megawatt-hours of capacity deficiency based on the utility planning criteria.

Table 20. Hourly Avoided Cost Analysis Summary

Location	Year Considered	Revenue Requirement	Total Hours of Capacity Deficiency	Total Annual MWh of Capacity Deficiency	Maximum $/kW/hr	Relative $/kW/hr Value Ranking
Pemi Substation (Bulk)	2020	$9,074,650	326	509	$2.45	11
Portsmouth Substation (Bulk)	2020	$3,037,438	1,966	7,446	$0.04	16
South Milford Substation (Bulk)	2020	$15,976,924	6,696	41,928	$0.05	14
Monadnock Substation (Bulk)	2020	$17,374,146	15	10.53	$203.68	6
East Northwood Substation (Non-Bulk)	2021	$242,995	3	0.07	$256.77	5
Rye Substation (Non-Bulk)	2022	$3,644,926	2	0.10	$3,185.54	2
Bristol Substation (Non-Bulk)	2020	$1,457,970	5	0.43	$301.37	4
Madbury ROW Circuit (34.5 kV)	2020	$2,429,950	7	14	$17.03	8
North Keene Circuit (12.47 kV)	2028	$1,858,912	1	0.11	$1,128.25	3
Londonderry Circuit (34.5 kV)	2020	$747,210	467	115.81	$1.01	13
Vilas Bridge Substation (Non-Bulk)	2020	$2,715,803	909	247.68	$2.91	10
Mount Support Substation (Bulk)	2020	$7,557,017	1,329	21,484	$0.04	15
Golden Rock Substation (Bulk)	2020	$8,983,404	164	434	$3.14	9
Bow Bog Substation (Non-Bulk)	2026	$299,375	5	0.27	$128.17	7
Dow's Hill Substation (Bulk)	2022	$525,674	2	0.008	$4,483.12	1
Kingston Substation (Bulk)	2020	$14,371,184	203	789	$2.00	12

Source: Guidehouse

The results for each hour for the 16 selected locations is presented in Table 21. The first row for each location is the maximum deficiency seen across the whole year in each hour. The second row is the sum of the deficiency per hour for 1 year. The third row is the count of the hours with capacity deficiency across 1 year. The fourth row is the resulting hourly avoided cost value in terms of $/kW/hr.

[46] This hourly analysis was completed for 2020 for all locations where there was a capacity deficit in 2020 or for the first year of capacity deficit if that occurred after 2020. For some locations, the capacity deficit was so low in the first year, that the second year of capacity deficit was used for the hourly analysis.

Table 21. Hourly Avoided Cost Detailed Results by Location (Selected Locations 1-8 on 1st page and 9-16 on 2nd page)

EDC	Substation	Parameter	Hour of Day																							
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Eversource	Pemi Substation (Bulk)	Max Deficiency per Hour (MW)						6	1	2	3	2	3	3	3	5	6	5	6	8	8	5	5	4	2	0
		Sum of Deficiency per Hour for One Year (MW)						6	2	7	12	18	15	17	16	23	25	37	53	81	84	57	37	15	4	0
		Count of Hours with Deficiency for One Year						1	4	7	13	16	16	14	13	16	14	21	30	41	42	36	25	13	3	1
		Hourly Avoidance Value ($/kW/hr)						$ 0.07		$ 0.07	$ 0.07	$ 0.18	$ 0.07	$ 0.18	$ 0.18	$ 0.18	$ 0.36	$ 0.55	$ 0.85	$ 2.45	$ 2.45	$ 1.25	$ 0.55	$ 0.07		
	Portsmouth Substation (Bulk)	Max Deficiency per Hour (MW)	4	3	3	3	4	5	7	8	9	10	10	11	12	12	12	12	11	10	8	7	7	6	6	4
		Sum of Deficiency per Hour for One Year (MW)	46	35	31	31	42	79	123	189	354	482	602	660	704	727	703	642	538	433	314	237	205	129	81	58
		Count of Hours with Deficiency for One Year	24	24	19	21	23	24	33	59	98	133	150	155	160	160	157	143	132	113	94	74	68	44	32	26
		Hourly Avoidance Value ($/kW/hr)	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.01	$ 0.02	$ 0.02	$ 0.03	$ 0.04	$ 0.04	$ 0.04	$ 0.04	$ 0.03	$ 0.02	$ 0.02	$ 0.01	$ 0.01	$ 0.01	$ 0.00	$ 0.00	$ 0.00
	South Milford Substation (Bulk)	Max Deficiency per Hour (MW)	10	8	7	7	7	9	12	14	14	15	17	19	20	21	22	22	23	23	22	21	19	17	15	12
		Sum of Deficiency per Hour for One Year (MW)	474	318	239	248	345	704	1432	1879	2114	2171	2208	2193	2216	2232	2199	2236	2566	3007	3100	2956	2739	2149	1410	793
		Count of Hours with Deficiency for One Year	194	164	144	146	166	242	280	296	314	312	313	317	317	316	312	317	320	326	330	331	332	332	318	257
		Hourly Avoidance Value ($/kW/hr)							$ 0.01	$ 0.01	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.02	$ 0.03	$ 0.05	$ 0.05	$ 0.05	$ 0.03	$ 0.02	$ 0.01	$ 0.01
	Monadnock Substation (Bulk)	Max Deficiency per Hour (MW)															0.1	0.6	0.8	1.4	1.5	0.8	0.4			
		Sum of Deficiency per Hour for One Year (MW)															0.1	0.6	1.9	3.5	2.6	1.4	0.5			
		Count of Hours with Deficiency for One Year															1	1	3	3	3	2	2			
		Hourly Avoidance Value ($/kW/hr)															$ 2	$ 12	$ 55	$ 204	$ 97	$ 36	$ 10			
	East Northwood Substation (Non-Bulk)	Max Deficiency per Hour (MW)																			0.061	0.004				
		Sum of Deficiency per Hour for One Year (MW)																			0.061	0.004				
		Count of Hours with Deficiency for One Year																			2	1				
		Hourly Avoidance Value ($/kW/hr)																			$ 257	$ 11				
	Rye Substation (Non-Bulk)	Max Deficiency per Hour (MW)																0.03	0.07							
		Sum of Deficiency per Hour for One Year (MW)																0.03	0.07							
		Count of Hours with Deficiency for One Year																1	1							
		Hourly Avoidance Value ($/kW/hr)																$ 956	$3,186							
	Bristol Substation (Non-Bulk)	Max Deficiency per Hour (MW)																			0.09	0.16	0.11	0.01		
		Sum of Deficiency per Hour for One Year (MW)																			0.15	0.16	0.11	0.01		
		Count of Hours with Deficiency for One Year																			2	1	1	1		
		Hourly Avoidance Value ($/kW/hr)																			$ 256	$ 301	$ 155	$ 6		
	Madbury ROW Circuit (34.5 kV)	Max Deficiency per Hour (MW)											1	2	2	3	2			0	3					
		Sum of Deficiency per Hour for One Year (MW)											1	2	2	3	2			0	3					
		Count of Hours with Deficiency for One Year											1	1	1	1	1			1	1					
		Hourly Avoidance Value ($/kW/hr)											$ 3.2	$ 7.2	$ 7.2	$17.0	$ 7.2			$ 0.3	$17.0					

Legend
Lowest value → Highest value

EDC	Substation	Parameter	Hour of Day																							
			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Liberty	North Keene Circuit (12.47 kV)	Max Deficiency per Hour (MW)												0.11												
Liberty	North Keene Circuit (12.47 kV)	Sum of Deficiency per Hour for One Year (MW)												0.11												
Liberty	North Keene Circuit (12.47 kV)	Count of Hours with Deficiency for One Year												1												
Liberty	North Keene Circuit (12.47 kV)	Hourly Avoidance Value ($/kW/hr)												$ 1,128												
Liberty	Londonderry Circuit (34.5 kV)	Max Deficiency per Hour (MW)	0.2	0.1			2.4			2.8	5.2	0.3	0.5	0.6	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.7	0.5	0.3
Liberty	Londonderry Circuit (34.5 kV)	Sum of Deficiency per Hour for One Year (MW)	0.2	0.1			2.4			2.8	5.4	0.7	1.2	2.7	4.2	5.9	7.6	9.1	11.2	15.3	16.2	12.2	9.9	6.0	2.1	0.6
Liberty	Londonderry Circuit (34.5 kV)	Count of Hours with Deficiency for One Year	2	1			1			1	3	3	7	13	15	23	28	34	38	69	82	54	46	30	13	4
Liberty	Londonderry Circuit (34.5 kV)	Hourly Avoidance Value ($/kW/hr)					$ 0.03			$ 0.03	$ 0.14		$ 0.03	$ 0.03	$ 0.09	$ 0.14	$ 0.22	$ 0.31	$ 0.45	$ 1.01	$ 1.01	$ 0.45	$ 0.31	$ 0.14	$ 0.03	$ 0.01
Liberty	Vilas Bridge Substation (Non-Bulk)	Max Deficiency per Hour (MW)	0.3				0.4	0.3	0.8	0.9	2.5	2.4	2.2	2.0	1.7	1.4	1.3	1.9	1.4	1.4	0.9	0.8	0.7	0.5	0.3	
Liberty	Vilas Bridge Substation (Non-Bulk)	Sum of Deficiency per Hour for One Year (MW)	0.3				0.4	0.6	13.1	20.1	19.1	14.8	15.3	12.8	9.1	10.7	12.2	13.9	16.9	26.4	28.3	19.8	10.2	3.1	0.7	
Liberty	Vilas Bridge Substation (Non-Bulk)	Count of Hours with Deficiency for One Year	1				1	6	50	69	70	64	63	57	36	42	41	52	61	74	77	75	49	16	5	
Liberty	Vilas Bridge Substation (Non-Bulk)	Hourly Avoidance Value ($/kW/hr)	$ 0.01				$ 0.01	$ 0.01	$ 0.33	$ 0.64	$ 0.64	$ 0.33	$ 0.33	$ 0.33	$ 0.19	$ 0.19	$ 0.19	$ 0.33	$ 0.33	$ 1.40	$ 2.91	$ 0.64	$ 0.19	$ 0.09	$ 0.01	
Liberty	Mount Support Substation (Bulk)	Max Deficiency per Hour (MW)	11	7					5	18	34	38	45	52	57	61	63	56	48	44	39	36	31	34	27	17
Liberty	Mount Support Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)	21	11					8	153	557	1051	1525	1828	1995	2257	2458	2265	2034	1697	1292	907	685	475	203	63
Liberty	Mount Support Substation (Bulk)	Count of Hours with Deficiency for One Year	4	2					4	28	49	69	86	92	108	114	120	114	113	103	91	77	65	51	28	11
Liberty	Mount Support Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)								$ 0.00	$ 0.00	$ 0.01	$ 0.02	$ 0.02	$ 0.02	$ 0.04	$ 0.04	$ 0.04	$ 0.02	$ 0.02	$ 0.02	$ 0.01	$ 0.00	$ 0.00	$ 0.00	
Liberty	Golden Rock Substation (Bulk)	Max Deficiency per Hour (MW)											2	5	7	8	9	10	10	9	7	5	3	2	0	0
Liberty	Golden Rock Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)											3	14	31	56	75	84	65	53	29	13	6	3	0	0
Liberty	Golden Rock Substation (Bulk)	Count of Hours with Deficiency for One Year											2	6	14	21	24	24	23	19	15	7	4	3	1	1
Liberty	Golden Rock Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)											$ 0.05	$ 0.18	$ 0.43	$ 1.01	$ 1.98	$ 3.14	$ 1.40	$ 1.01	$ 0.43	$ 0.18	$ 0.05	$ 0.05		
Unitil	Bow Bog Substation (Non-Bulk)	Max Deficiency per Hour (MW)														0.02	0.07	0.08	0.06	0.04						
Unitil	Bow Bog Substation (Non-Bulk)	Sum of Deficiency per Hour for One Year (MW)														0.02	0.07	0.08	0.06	0.04						
Unitil	Bow Bog Substation (Non-Bulk)	Count of Hours with Deficiency for One Year														1	1	1	1	1						
Unitil	Bow Bog Substation (Non-Bulk)	Hourly Avoidance Value ($/kW/hr)														$ 17	$ 85	$ 128	$ 74	$ 39						
Unitil	Dow's Hill Substation (Bulk)	Max Deficiency per Hour (MW)																	0.004	0.005						
Unitil	Dow's Hill Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)																	0.004	0.005						
Unitil	Dow's Hill Substation (Bulk)	Count of Hours with Deficiency for One Year																	1	1						
Unitil	Dow's Hill Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)																	$ 4,483	$ 4,483						
Unitil	Kingston Substation (Bulk)	Max Deficiency per Hour (MW)												3	5	8	10	10	11	11	10	9	8	6	3	
Unitil	Kingston Substation (Bulk)	Sum of Deficiency per Hour for One Year (MW)												8	33	57	84	101	107	109	106	84	57	33	10	
Unitil	Kingston Substation (Bulk)	Count of Hours with Deficiency for One Year												6	14	18	21	23	23	24	23	22	15	9	5	
Unitil	Kingston Substation (Bulk)	Hourly Avoidance Value ($/kW/hr)												$ 0.09	$ 0.31	$ 0.72	$ 1.09	$ 1.64	$ 2.00	$ 2.00	$ 2.00	$ 1.09	$ 0.72	$ 0.31	$ 0.09	

Source: Guidehouse

Legend
Lowest value → Highest value

4.3 Mapping of DG Production Profiles with Distribution Capacity Need

This section maps NEM-eligible DG production profiles with hours of distribution capacity need at each of the 16 selected locations. It assesses whether solar PV output aligns with hours of distribution capacity need, and where and when energy storage is required in conjunction with solar PV to provide energy for all hours during which capacity deficits occur. It is structured to illustrate when DG production profiles align with hours of capacity need, but not to quantify the amount of DG or storage needed to avoid distribution capacity investments.

The comparison of load versus DG production profiles should be viewed as a high level illustration of the alignment of DG production profiles on days where the number of hours and magnitude of capacity deficiency is highest for each of the 16 locations. The LVDG study determines the potential value of distribution capacity avoidance and should not be construed as a locational non-wires solution (NWS) assessment.

An NWS study typically includes a detailed analysis of all hours of the year where capacity deficiencies exist, with an economic analysis of trade-offs of different mixes of DG and other demand reduction resources (e.g., standalone solar versus solar paired with energy storage, demand response, or targeted energy efficiency), including the amount of effective load reduction required over each year of the study. Equally important, an NWS would include a determination of the amount of DG or load reduction measures—or a portfolio including both—needed to reliably avoid a traditional distribution capacity investment.[47] Other considerations include the value of load reductions and associated reduced energy costs on a time-differentiated basis over all hours of the years. Similarly, an NWS considers transmission impacts for both pool (ISO-NE Regional Network Service) and non-pooled transmission assets (Local Network Service) for each EDC within New Hampshire. The LVDG study only considers the value of capacity avoidance for distribution assets and does not consider the ability of a specific solution to fully achieve avoidance values. Any NWS assessment would need to evaluate all of these considerations and should be conducted on a case by cases basis.

The illustrative mapping analysis includes the following steps:

1. Determine distribution capacity deficits for seasonal peaks for the most recent year that hourly data is available from the EDC
2. Generate 24-hour seasonal peak day load profiles for each location
3. Develop 24-hour average solar PV production profiles using NREL's PVWatts Calculator (fixed and two-axis tracking)

[47] For example, locational Equivalent Load Carrying Capability (ELCC) studies of distribution level assets.

4. Select appropriate average profile from among fixed variants, one- and two-axis tracking
5. Compare normalized hourly solar PV production profile and load profiles for seasonal peak days
6. Illustrate the coincidence of solar PV production during hours of distribution capacity needs[48]
7. Compare solar PV paired with energy storage charge/discharge profiles at locations where solar PV production does not fully align with hours of need
8. Add the production profile for representative run-of-river hydro unit at each location to further evaluate DG coincidence with peak

4.3.1 Load and DG Production Profiles

This section presents detailed solar PV, solar PV paired with energy storage, and hydro production profiles on representative days with distribution capacity deficiencies. Two locations, Pemi and Portsmouth, are highlighted in this section. Detailed production profiles for three additional locations, Madbury, Kingston, and Mount Support, appear in Appendix E. A complete, abbreviated set of 16 locational analyses and production profiles is presented in tabular form at the end of Section 4.3.2.

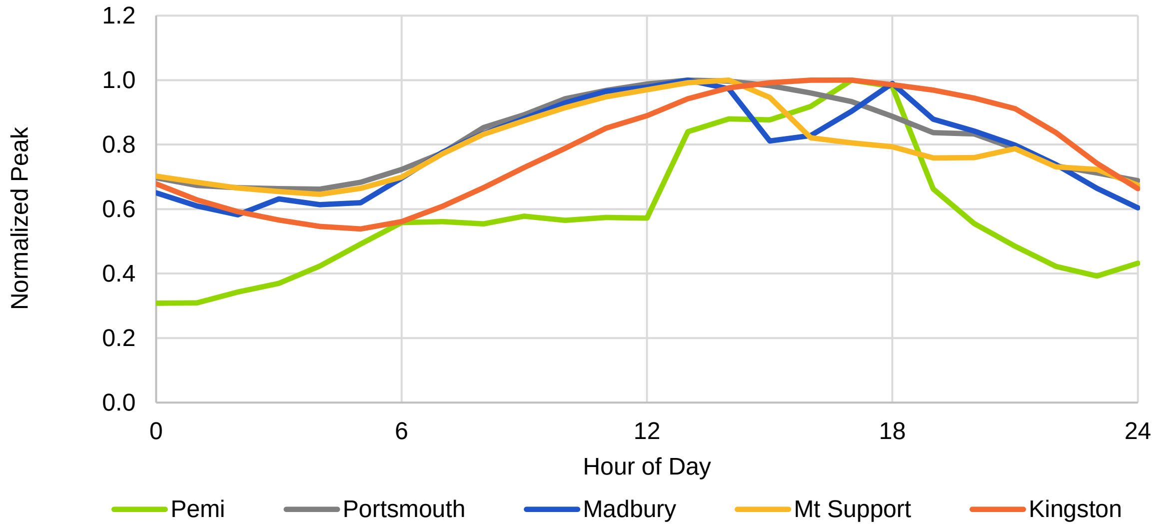
The first step in the study's mapping process includes development of hourly average monthly and peak load profiles for each of the 16 selected locations. Figure 43 presents peak day hourly load profiles for the two locations in this section, and the three additional locations that appear in Appendix E. The profiles include, at minimum, the following characteristics and attributes:

- At least one location for each EDC
- Distribution line and substation capacity deficiencies
- Normal (N-0) and contingency (N-1) capacity deficiencies
- Bulk and non-bulk substations
- Load data for each location for the first year where a full years' hourly data is available (2018 or 2019)

The mapping of DG profiles (solar PV, solar PV paired with storage, and hydro) to peak day load profiles is presented in next section. Hourly profiles for the five locations with peak day load are presented in Figure 43, Table 22 indicates that four of the five locations are summer peaking.

[48] Coincidence is defined as hours when there is a capacity deficiency during which hours solar PV production is non-zero

Figure 43. Peak Day Load for Five Example Locations



Source: Guidehouse, EDC data

Table 22. Summary of Locational Peak Load at 16 Selected Locations

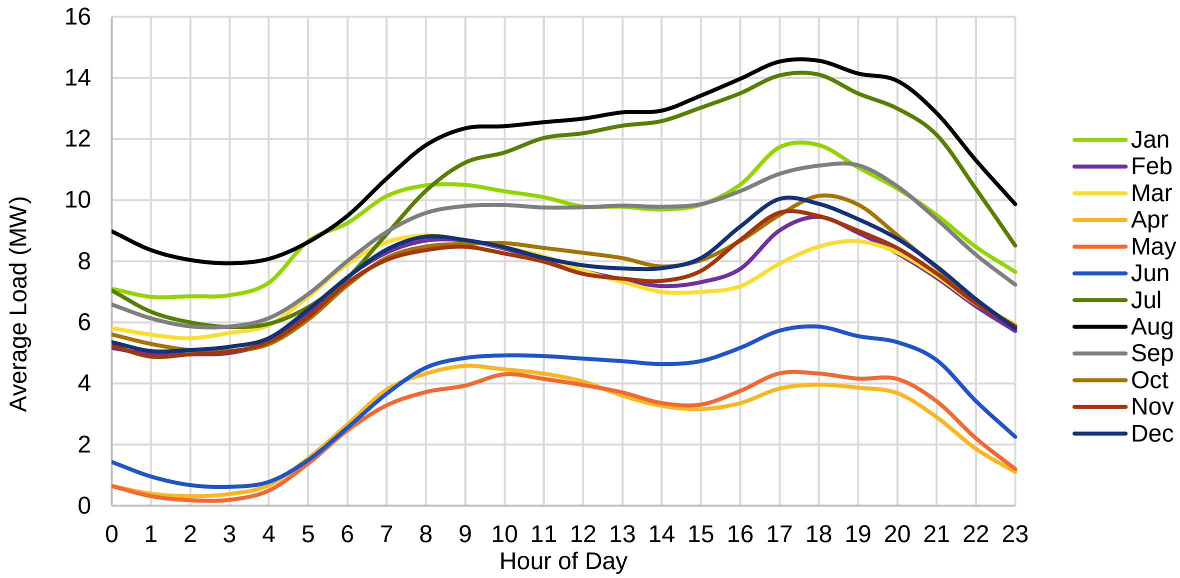
EDC	Location	Region	Winter (Peak and Date Time)	Summer (Peak and Date Time)
Eversource	Pemi Substation (Bulk)	Northern	23 MW 1/7/19 17:00	
Eversource	Portsmouth Substation (Bulk)	Eastern		40 MW 7/30/19 13:00
Eversource	South Milford Substation (Bulk)	Southern	36.9 MW 1/21/19 17:00	41.4 MW 7/30/19 17:00
Eversource	Monadnock Substation (Bulk)	Western	34.4 MW 1/16/19 17:00	34.9 MW 7/19/19 18:00
Eversource	East Northwood Substation (Non-Bulk)	Eastern		5.7 MW 7/21/19 18:00
Eversource	Rye Substation (Non-Bulk)	Eastern		4.2 MW 7/21/19 16:00
Eversource	Bristol Substation (Non-Bulk)	Northern		6.3 MW 7/20/19 19:00
Eversource	Madbury ROW Circuit (34.5 kV)	Eastern		32.58 MW 7/20/19 13:00
Eversource	North Keene Circuit (12.47 kV)	Northern		10.9 MW 6/28/19 11:00
Eversource	Londonderry Circuit (34.5 kV)	Southern		2.63 MW 6/24/19
Liberty	Vilas Bridge Substation (Non-Bulk)	Walpole	4.39 MW 2/24/19 16:00	4.21MW 8/19/19 15:00
Liberty	Mount Support Substation (Bulk)	Lebanon		40.9 MW 7/30/19 14:00
Liberty	Golden Rock Substation (Bulk)	Salem		49.27 MW 7/30/19 15:00
Unitil	Bow Bog Substation (Non-Bulk)	Capital		3077 kW 7/30/19 15:00
Unitil	Dow's Hill Substation (Bulk)	Seacoast		1679 kW 8/29/2018 17:00
Unitil	Kingston Substation (Bulk)	Seacoast		51 MW 8/29/18 17:00

Source: Guidehouse, EDC data

Figure 44 and Figure 45 present average hourly monthly load profiles for two locations, Pemi and Portsmouth. Each figure is derived using 2018 or 2019 EDC hourly data obtained from substation SCADA readings. Details for these two locations are listed below:

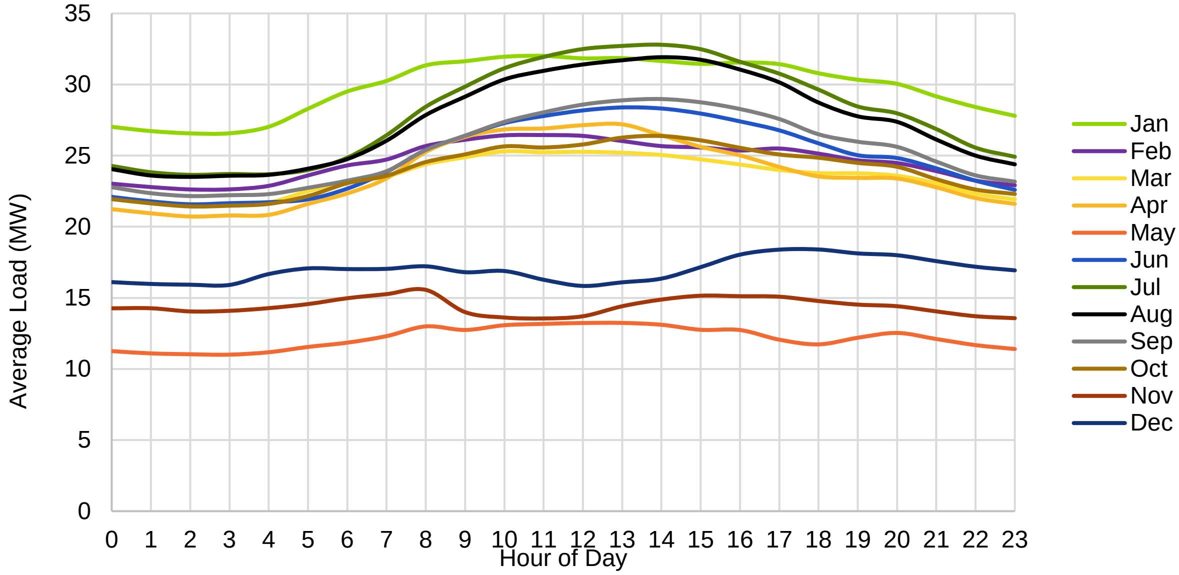
- Pemi Substation (Bulk):
  - Winter peaking with a daily average peak in the early evening
  - Annual Peak Day: 1/7/2019 17:00, 23 MW
- Portsmouth Substation (Bulk)
  - Summer midday peaking substation
  - Annual Peak Day: 7/30/2019 13:00, 40 MW

Figure 44. Average Hourly Profile by Month – Pemi Substation (Bulk)



Note: Although the peak day occurs in January, average January load is much lower than that of the summer months.
Source: Guidehouse, EDC data

Figure 45. Average Hourly Profile by Month – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

Solar PV Configurations Considered

Multiple solar PV configurations are considered, ranging from fixed-axis to single and dual-axis tracking, outlined in Table 23.

Table 23. Solar PV Configurations Considered

Solar PV Configurations Considered	Orientation
Fixed – 135	SE
Fixed – 180	S
Fixed – 225	SW
Fixed – 270	W
Single Axis Tracking	NA
Dual Axis Tracking	NA

Source: Guidehouse

A central New Hampshire location (Figure 46) was selected after the examination of various locations confirmed that differences in solar PV production were minimal and would not materially affect the analysis.

Figure 46. Location Selected for Solar PV Configurations

Source: National Renewable Energy Laboratory, Google Maps

Solar PV Configuration Comparison

Using PVWatts data, average and peak day summer (June-September) and average and peak day winter (November-February) 24-hour solar PV production profiles were created to align with seasonal peak capacity needs for a 1 kW (1,000 Watt) nameplate system (see Figure 47 and Figure 48, and Figure 49 and Figure 50, respectively). Average profiles were created for six orientations and peak day profiles for three orientations. The dual-axis tracking has the highest overall average production (W AC/W DC) while the fixed axis, with an azimuth angle of 180°,[49] has the highest overall production of the fixed array configurations.

[49] The azimuth angle is the angle clockwise from true north describing the direction that the array faces. An azimuth angle of 180° is for a south-facing array, and an azimuth angle of zero degrees is for a north-facing array.

Figure 47. Average Summer Production by Solar Array Configuration Type

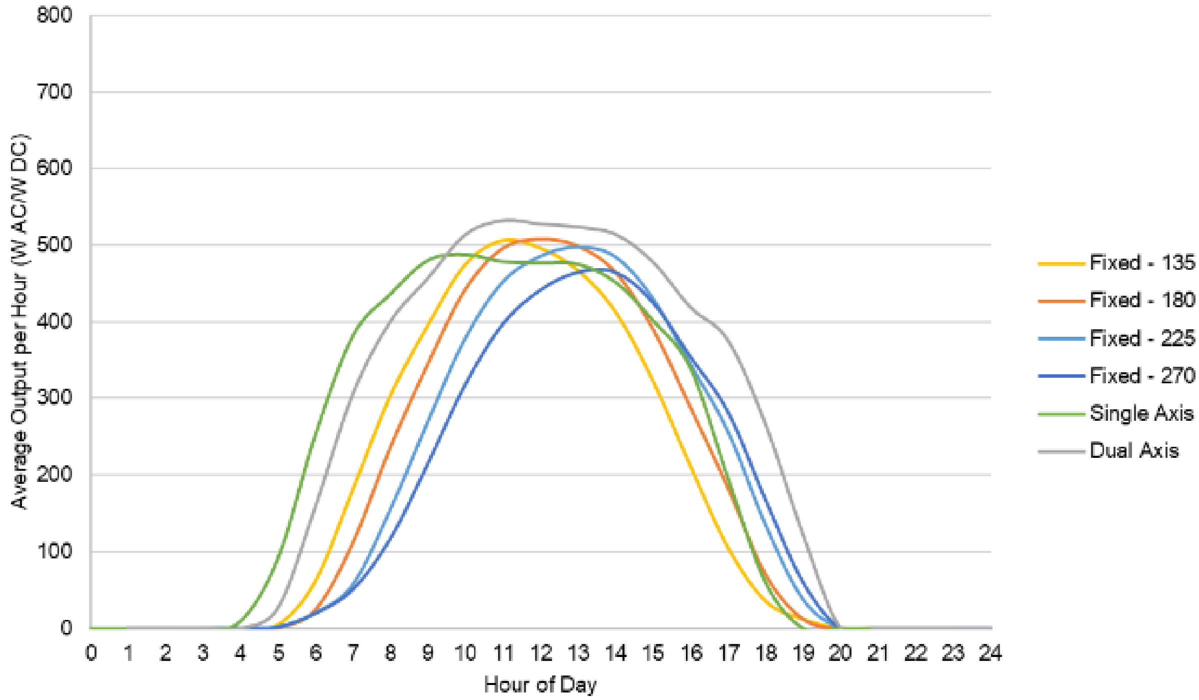
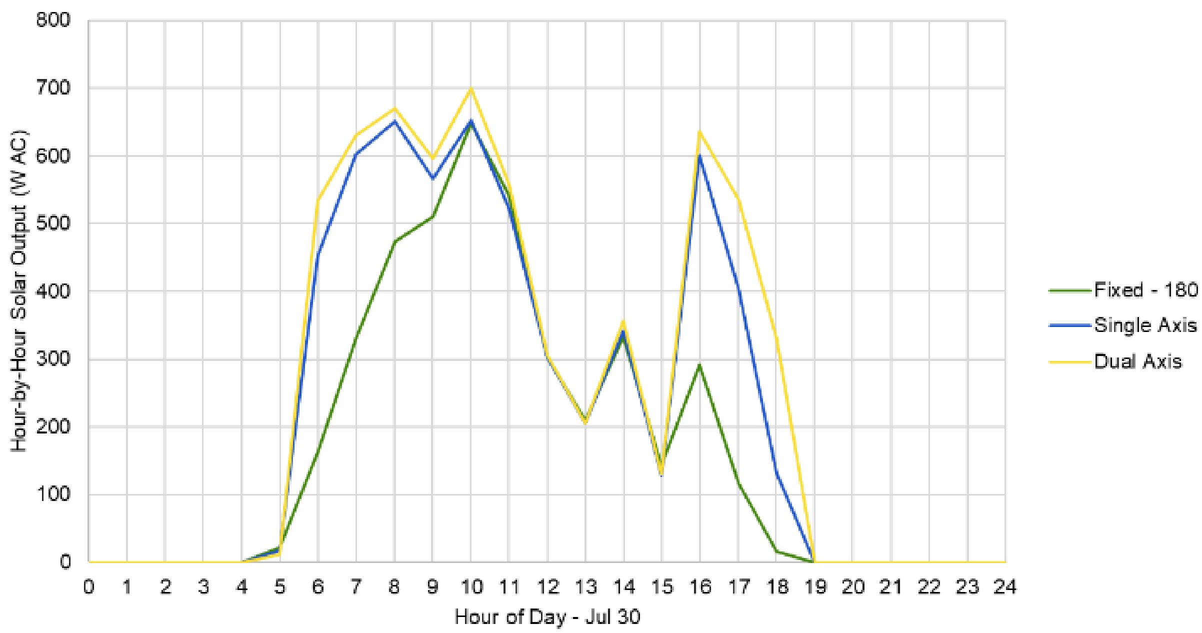


Figure 48. Peak Day Summer Production by Solar Array Configuration Type



Source: Guidehouse

Figure 49. Average Winter Production by Solar Array Configuration Type

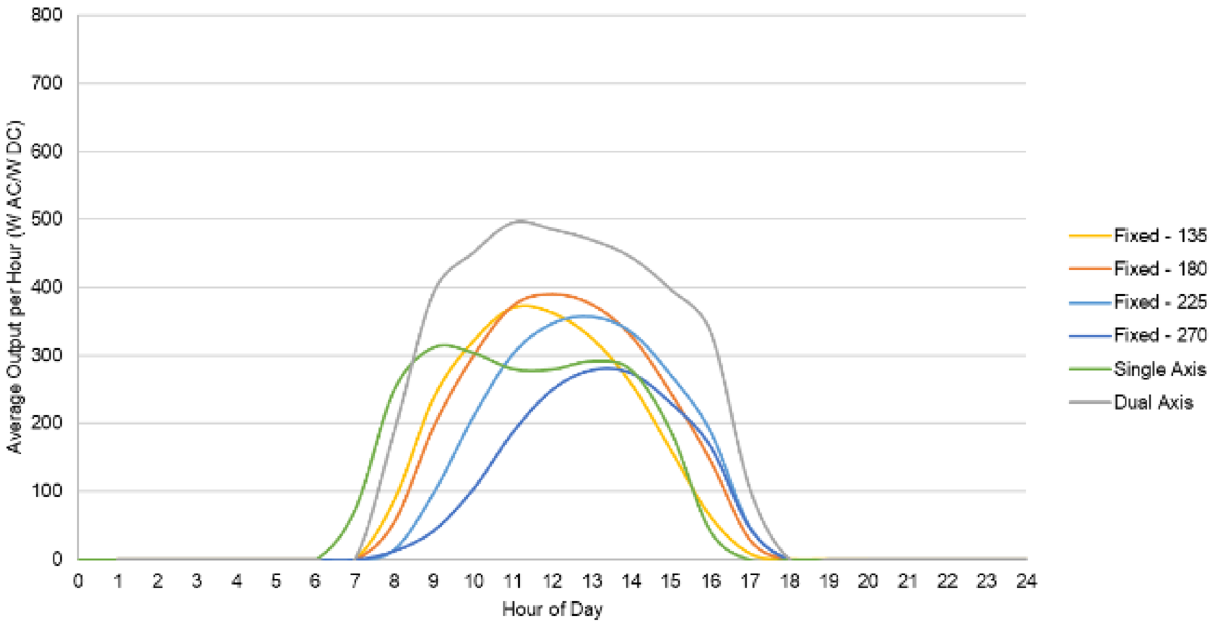
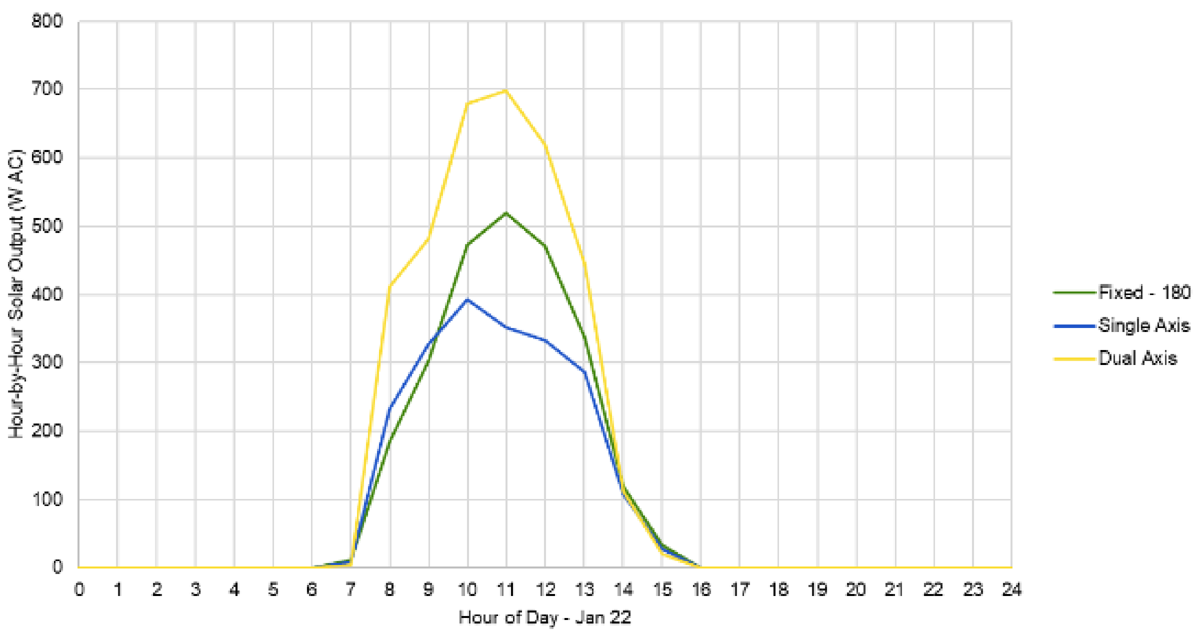


Figure 50. Peak Day Winter Production by Solar Array Configuration Type



Source: Guidehouse

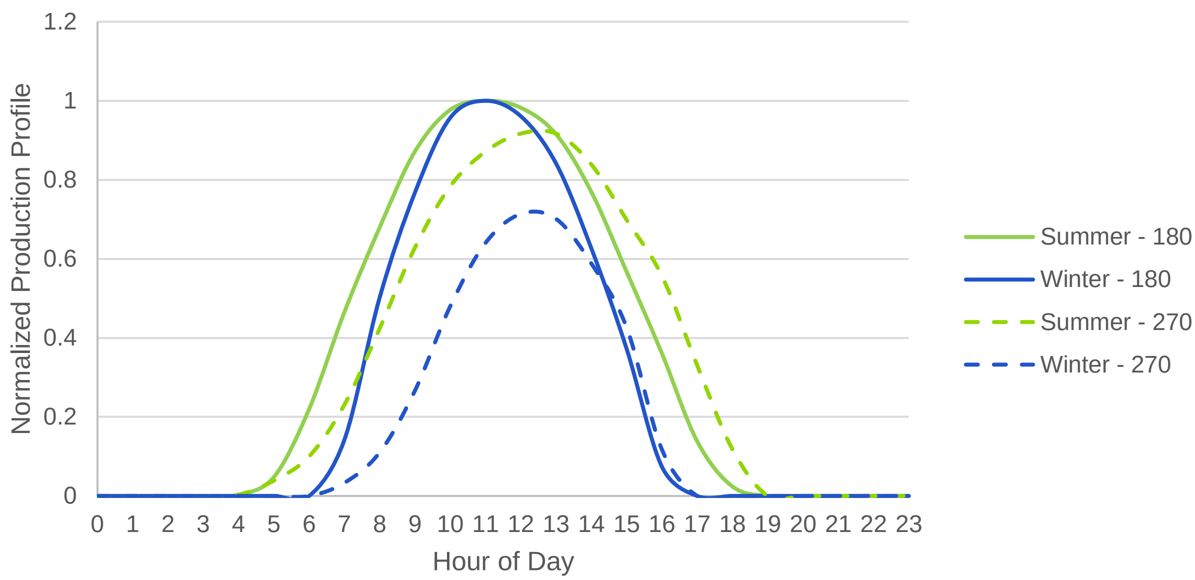
Selection of Representative Solar PV Production Profile

A fixed-180° solar PV production profile was selected to align with the hours of capacity deficiency for each of the selected locations. That decision is supported by the following considerations:

- The dual-axis tracking produces the highest amount of electricity; however, there are limitations with installation of dual-axis tracking. The costs (capital and O&M) are generally higher than fixed systems.
- Single-axis tracking provides a wider peak performance period, on average, at a lower capital cost than dual-axis tracking. However, the additional hours of production are earlier in the day and are generally not coincident with hours of peak electric demand.
- Of the fixed array options, the 180°-azimuth angle provides the highest total annual production and the highest seasonal average energy production. The higher overall production provides additional energy to charge storage when considering solar paired with storage.

Figure 51 illustrates the production profiles for solar PV with a fixed-180° orientation compared to a western facing device (i.e., fixed-270°), which show some differences such as a 1-hour shift in production during the summer for the fixed-270° orientation. However, the higher energy production from the fixed-180° suggests it is a better choice for comparing solar production profiles to the capacity deficiencies at all 16 locations.

Figure 51. Representative Solar PV Production Profiles – Normalized Fixed

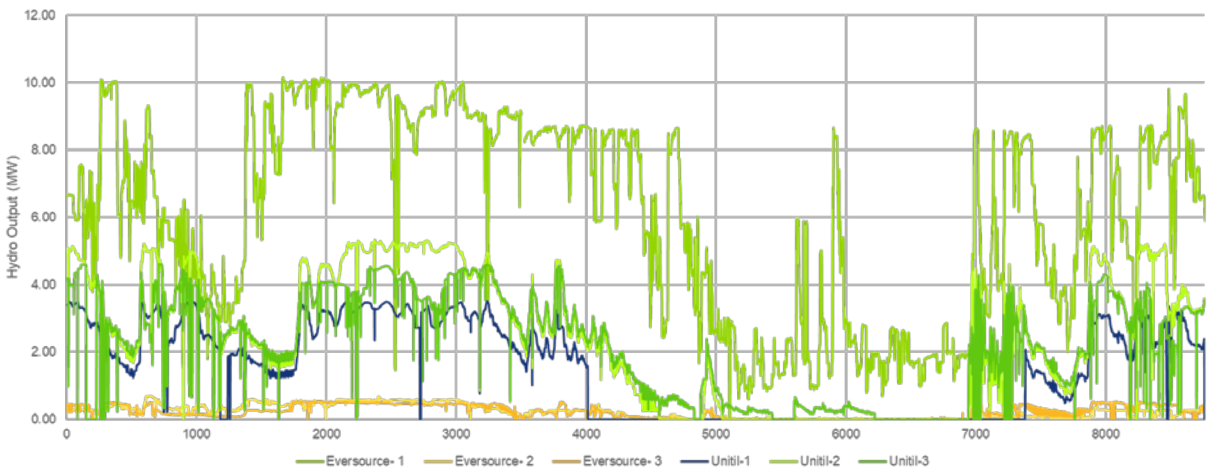


Note: Normalized to max for each season for the Fixed-180° case.
Source: Guidehouse

Hydro Production Analysis

The study reviewed recent hydro production profiles for six locations in Eversource's and Unitil's service territories as a proxy to determine seasonal and hourly variations at undeveloped sites.[50] Figure 52 through Figure 54 present the results of the analysis of the six hydro production profiles and their alignment with hours of capacity deficiency. Figure 52 presents actual hourly data for the entire year (8,760 hours). Figure 53 and Figure 54 present normalized 24-hour daily profiles for summer and winter months, respectively, where normalized values are equal to the average hourly output, expressed as a percent of maximum hydro output for each season.

Figure 52. Hydroelectric Production Analysis



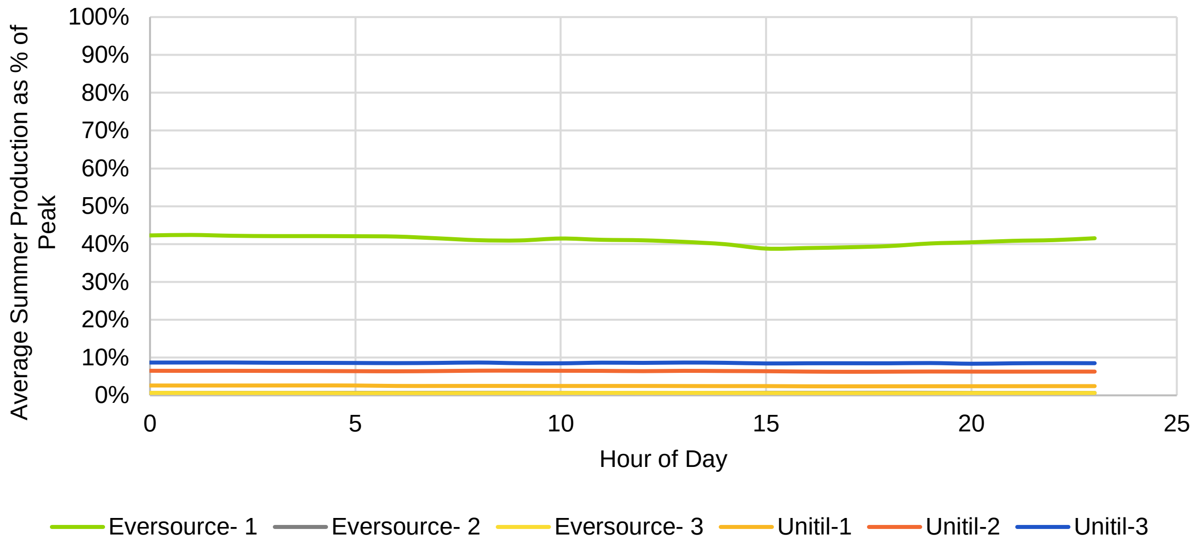
Source: Guidehouse, EDC data

Seasonal Average Hydro Production Profiles

Figure 53 and Figure 54 present the summer and winter average hydro generation production profiles. Winter production is generally higher than summer production as a percent of annual peak production.

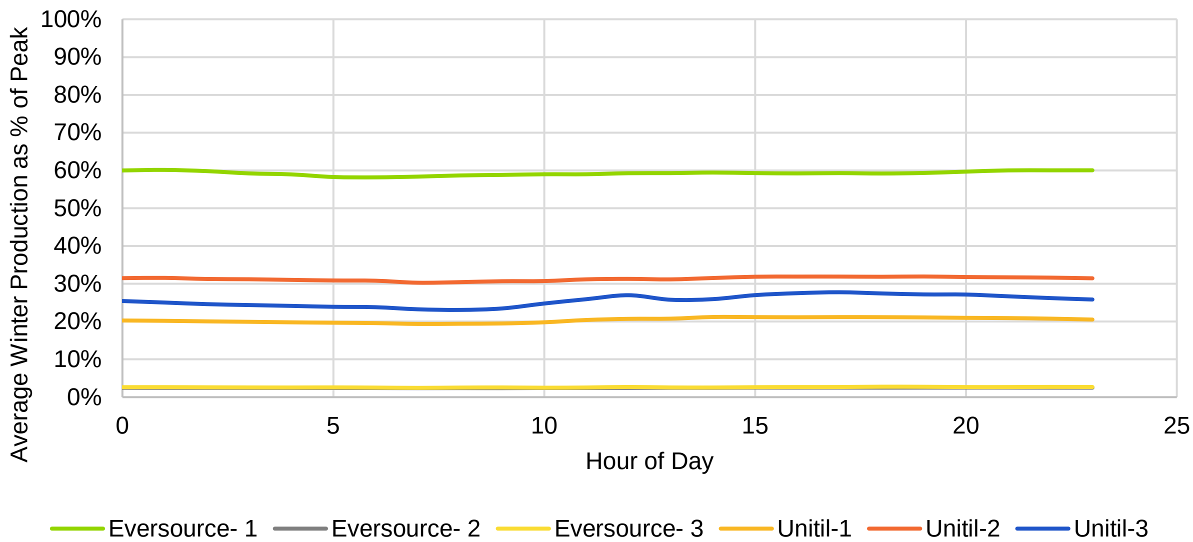
[50] The study did not include investigation of hydrological conditions at any potential sites near or adjacent to the 16 locations to develop representative production profiles.

Figure 53. Summer Average Hydro Production Profiles



Source: Guidehouse, EDC data

Figure 54. Winter Average Hydro Production Profiles



Source: Guidehouse, EDC data

4.3.2 Mapping of DG Production Profile with Capacity Deficiency Profile

This section compares the DG production profiles developed in Section 4.3.1 to the hours of capacity deficiencies for each of the 16 locations. Two locations, Eversource's Pemi and Portsmouth substations, are analyzed in detail for the first year when capacity deficiencies occur. Appendix E presents detailed analyses of three other locations and the final graphical result for the remaining 11 sites.

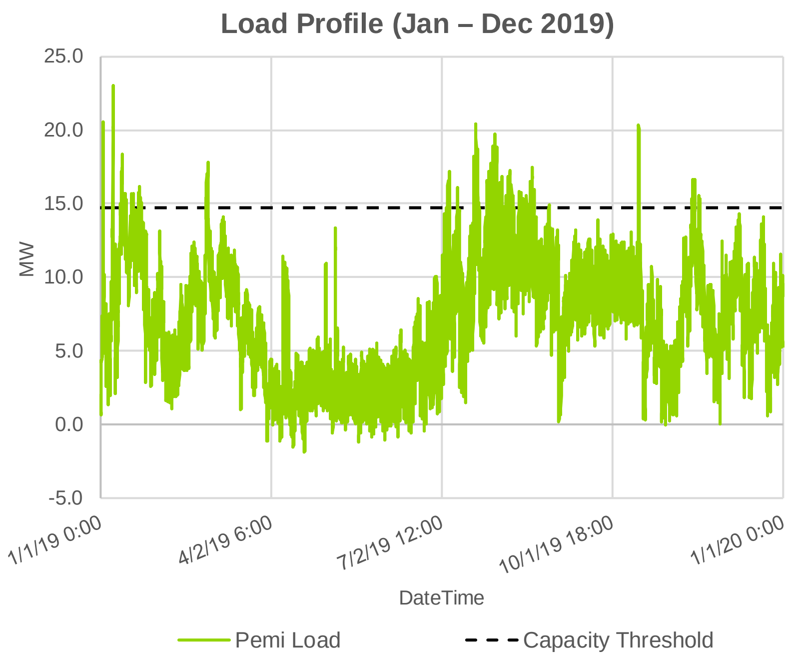
Pemi Substation (Bulk) Analysis

Figure 55 presents historical hourly loads for the Pemi substation, a late day winter peaking location with normal overloads, with the distribution capacity threshold superimposed. The figure indicates capacity limits are exceeded at the Pemi station during winter and summer months.

The duration and energy deficiencies at Pemi follows:

- Hours of capacity deficiency: 326
- Energy deficiency: 508.7 MWh (Approximately, 0.8% of total energy (63,137 MWh)

Figure 55. Annual Hourly Profile – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

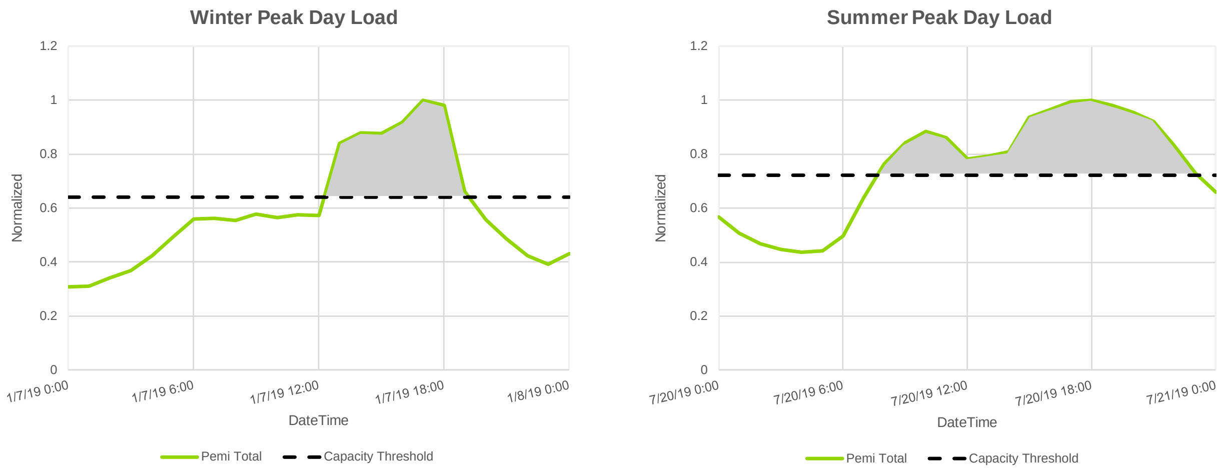
Table 24. Annual Load Profile and Capacity Threshold – Pemi Substation (Bulk)

Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Pemi Substation (Bulk)	**Northern**	**23**	**1/7/19 17:00**	**8.29**

Source: Guidehouse, EDC data

Figure 56 presents winter and summer peak day capacity deficiencies at the Pemi substation, normalized to values on a common, per unit scale. The figure indicates that the duration of the winter peak is narrower than summer and occurs later in the day.

Figure 56. Seasonal Capacity Deficiencies – Pemi Substation (Bulk)

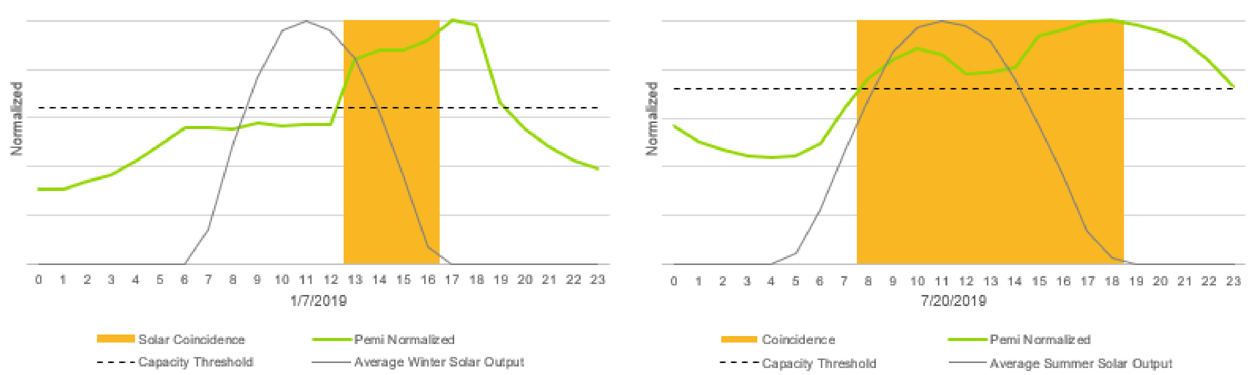


Source: Guidehouse, EDC data

Figure 57 presents normalized single-axis solar PV output versus hourly loads for the Pemi substation for the winter and summer peaks. The figure indicates that solar coincidence is greater during summer months. However, solar PV alone is unable to meet capacity deficits during early evening hours when solar PV output is low, as follows:

- Hours of capacity need: 7 hours (winter) vs. 16 hours (summer)
- Winter solar coincidence: 4 out of 7 hours
- Summer solar coincidence: 11 out of 16 hours

Figure 57. Solar Mapping – Pemi Substation

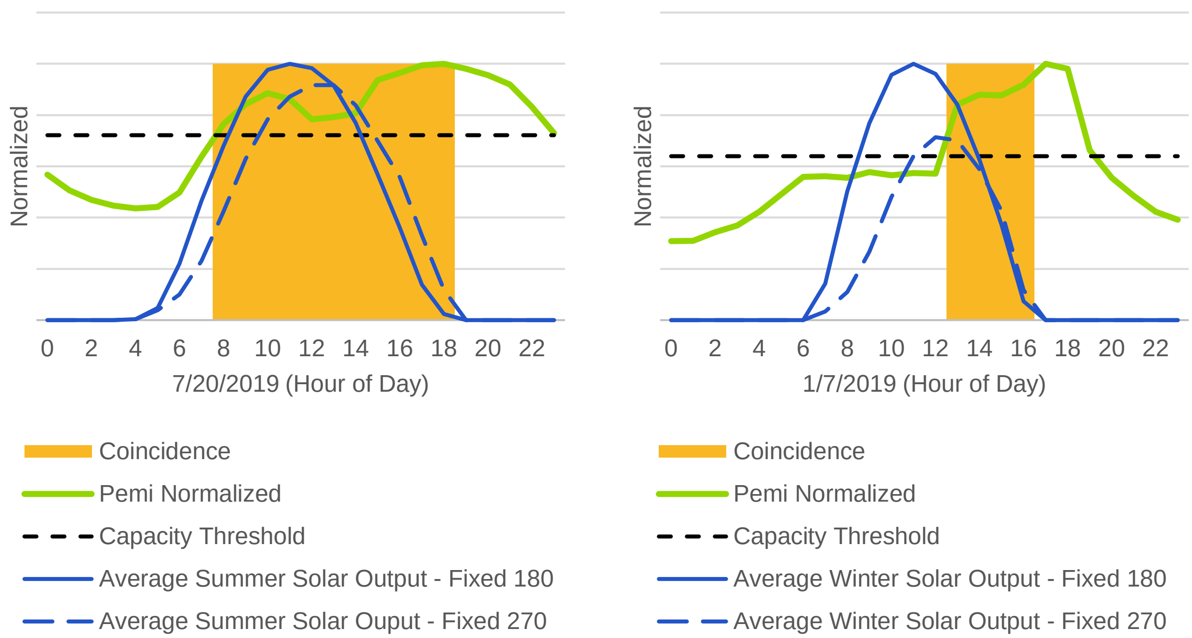


Source: Guidehouse, EDC data

Pemi Substation (Bulk) – Solar Coincidence Analysis – Fixed Axis: 180 and 270

Figure 58 shows the difference between the solar PV production based on different azimuth angles (south at 180° and west at 270° angle). While the fixed-270° has a later peak than the fixed-180° orientation, the height of the peak is much lower, and the coincidence hours are equivalent.

Figure 58. Solar Coincidence Analysis – Fixed Axis: 180° and 270° – Pemi Substation



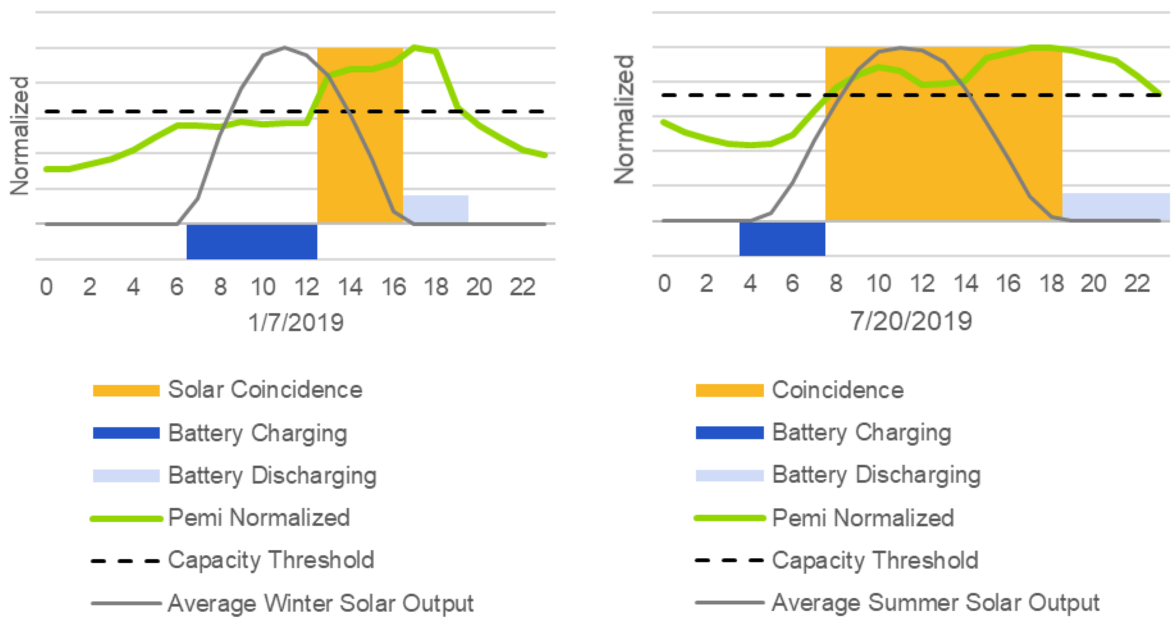
Source: Guidehouse, EDC data

Pemi Substation (Bulk) – Solar and Supplemental Storage

Figure 59 illustrates the hours when supplemental energy storage is needed for DG output to fully align with hours of capacity deficiencies. While these figures are illustrative, the pairing of solar with energy storage confirms the combination is better suited to address capacity deficiencies at Pemi. The figure indicates that the available number of charging hours are greater in the winter and required number of charging and discharging hours are greater in summer, summarized as follows:

- Winter charging interval: 6 hours, 3 hours discharge
- Summer charging interval: 4 hours, 5 hours discharge

Figure 59. Solar plus Storage Charging Analysis – Pemi Substation (Bulk)

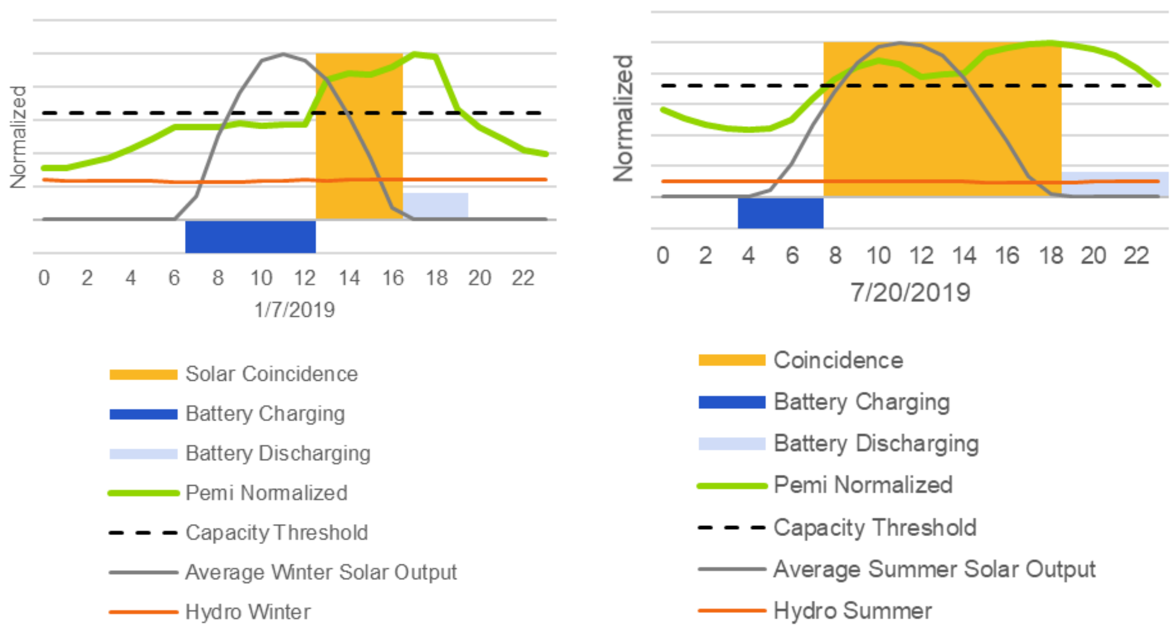


Source: Guidehouse, EDC data

Pemi Substation (Bulk) – Solar, Storage, and Hydro Coincidence Analysis

In Figure 60, summer and winter hydro production profiles are added to illustrate the coincidence of hydro production and the offset to solar and battery production requirements.

Figure 60. Solar, Storage, Hydro Coincidence Analysis – Pemi Substation



Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) Analysis

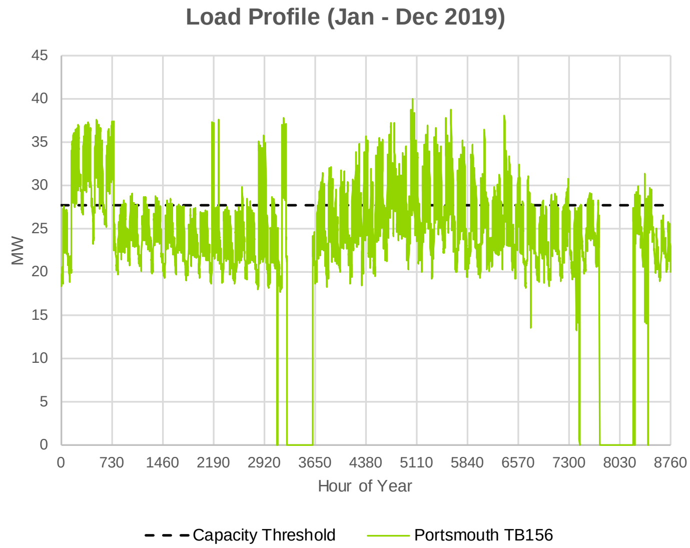
Figure 61 presents hourly profiles for the Portsmouth substation, a midday peaking bulk substation, where capacity deficiencies occur many hours during the year. These deficiencies occur during winter and summer months and are caused by insufficient transformation capacity to back up the contingency loss of one of two transformers at Portsmouth.[51]

The duration and energy deficiencies at Portsmouth are as follows:

- Hours of capacity deficiency: 1,966
- Energy deficiency: 7,446 MWh (Approximately, 3.7% of total energy (200,560 MWh)

[51] Portsmouth is an example of a bulk substation where the recently-modified system planning criteria affected the potential violation analysis, as a result of an increased number of hours of exposure for contingency overloads.

Figure 61. Annual Hourly Profile – Portsmouth Substation (Bulk)



Source: Guidehouse, EDC data

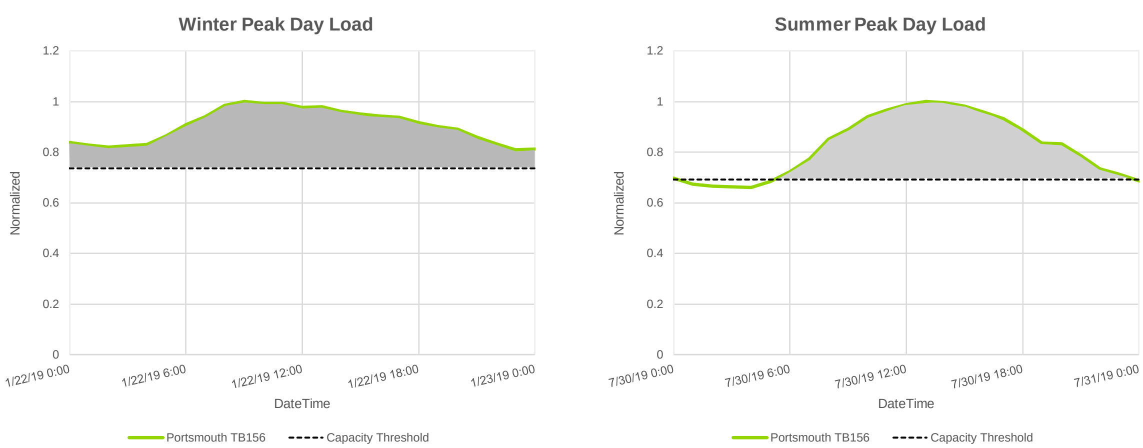
Table 25. Annual Load Profile and Capacity Threshold – Portsmouth Substation

Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Portsmouth Substation (Bulk)	**Eastern**	**40**	**7/30/19 13:00**	**12.3**

Source: Guidehouse, EDC data

Figure 62 illustrates the duration of capacity deficiencies at Portsmouth during winter and summer conditions. The figure indicates a significant number of hours of exposure for potential contingency overloads. It also indicates that significant solar PV production coupled with energy storage would better align with hours of capacity deficiencies during summer months, as there are fewer hours when energy storage discharge is needed to meet capacity deficiencies when solar production is zero.

Figure 62. Seasonal Capacity Deficiencies – Portsmouth Substation



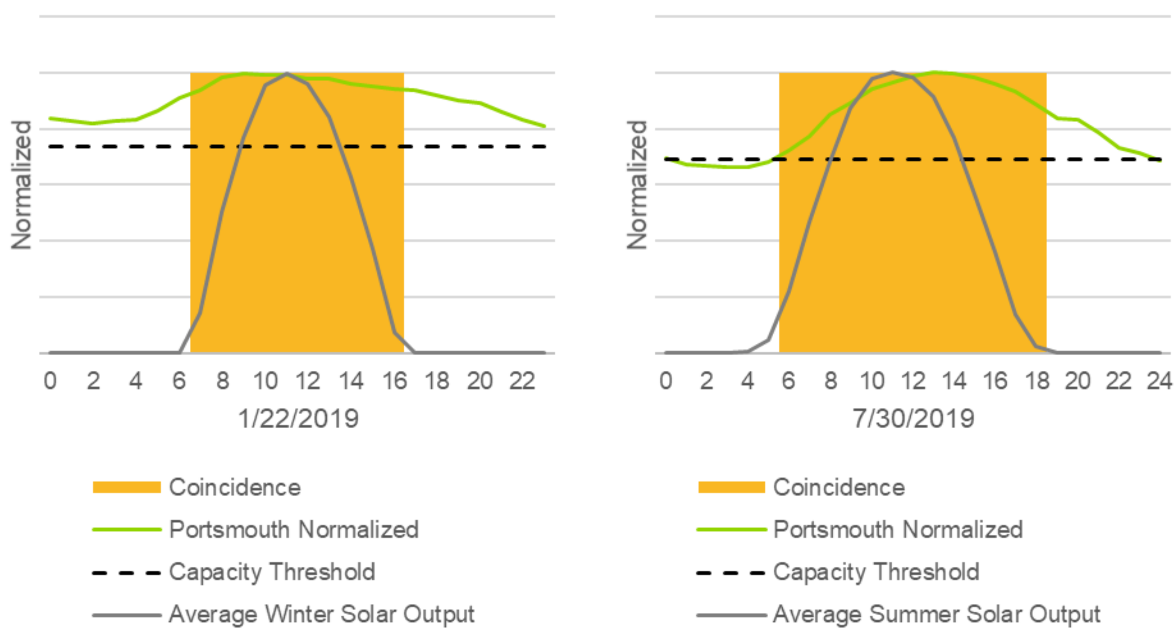
Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) – Solar Coincidence Analysis

Figure 63 indicates there is a greater number of hours in the summer where solar production coincides with hours of capacity deficiency. There is a large number of hours in winter where solar production is zero during hours of capacity deficiency.

- Winter coincidence interval: 10 out of 24 hours
- Summer coincidence interval: 13 out of 18 hours

Figure 63. Solar Coincidence Analysis – Portsmouth Substation (Bulk)



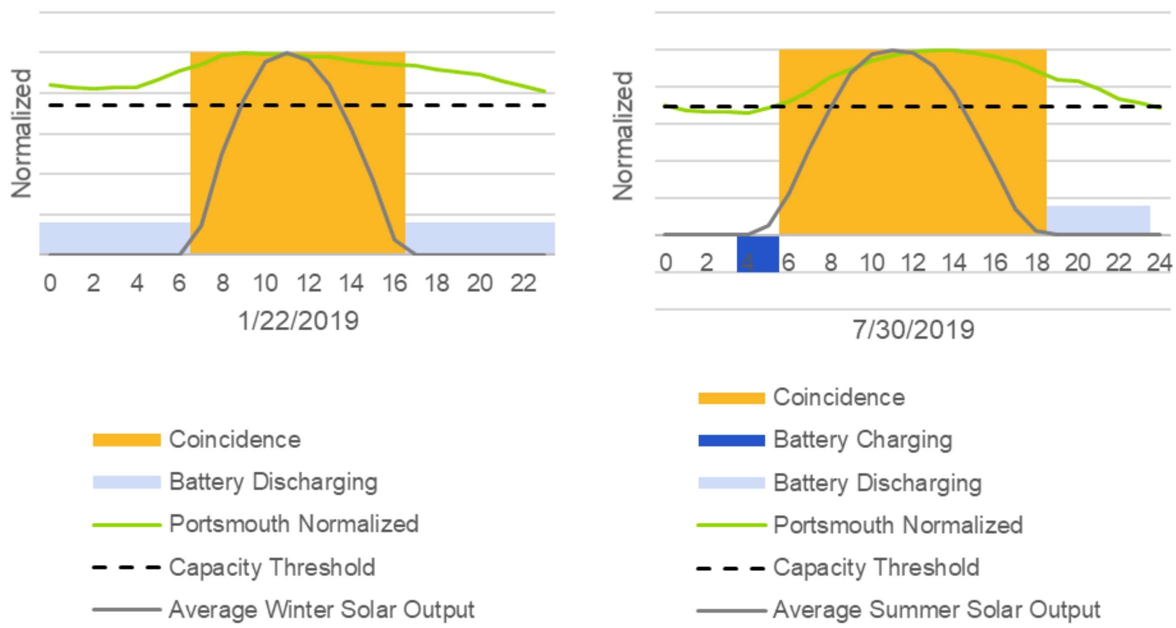
Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) – Solar and Supplement Storage Charging Analysis

Figure 64 indicates that the lengthy capacity deficiency interval constrains the availability of solar to charge battery storage, summarized as follows:

- Winter: No hours available for charging via solar, 12-hour discharge interval
- Summer 2-hour charging interval, 5-hour discharge interval

Figure 64. Solar plus Storage Charging Analysis – Portsmouth Substation (Bulk)

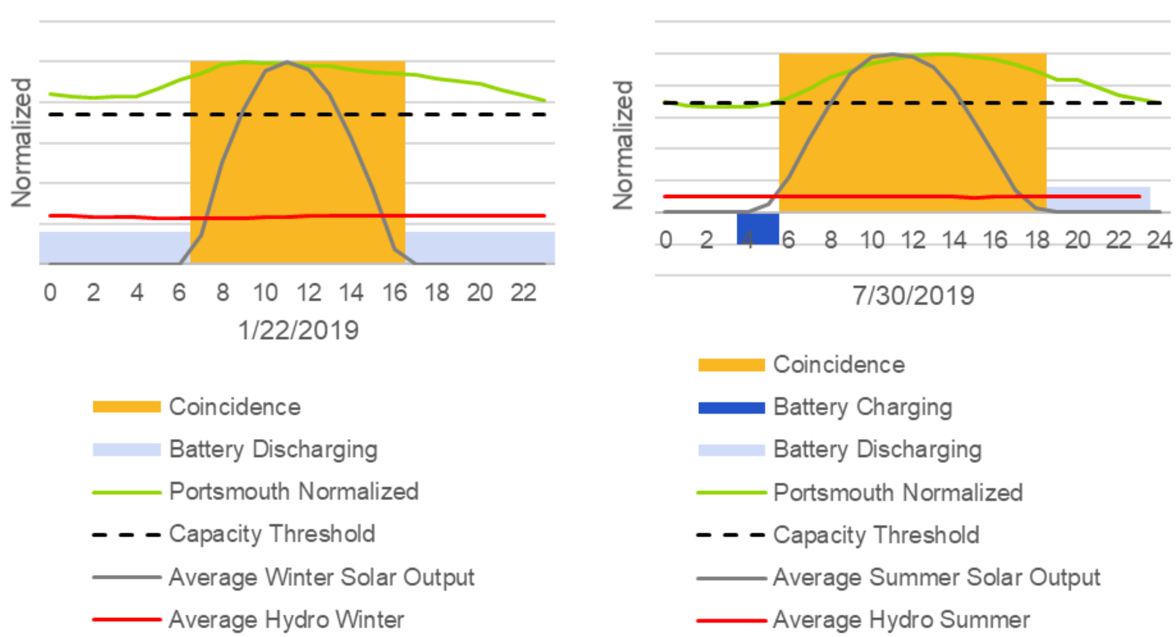


Source: Guidehouse, EDC data

Portsmouth Substation (Bulk) – Solar, Storage, and Hydro Coincidence Analysis

Figure 65 indicates that hydroelectric production in the winter is higher, which could offer greater support to address capacity deficiencies at Portsmouth.

Figure 65. Solar, Storage, and Hydro Coincidence Analysis – Portsmouth



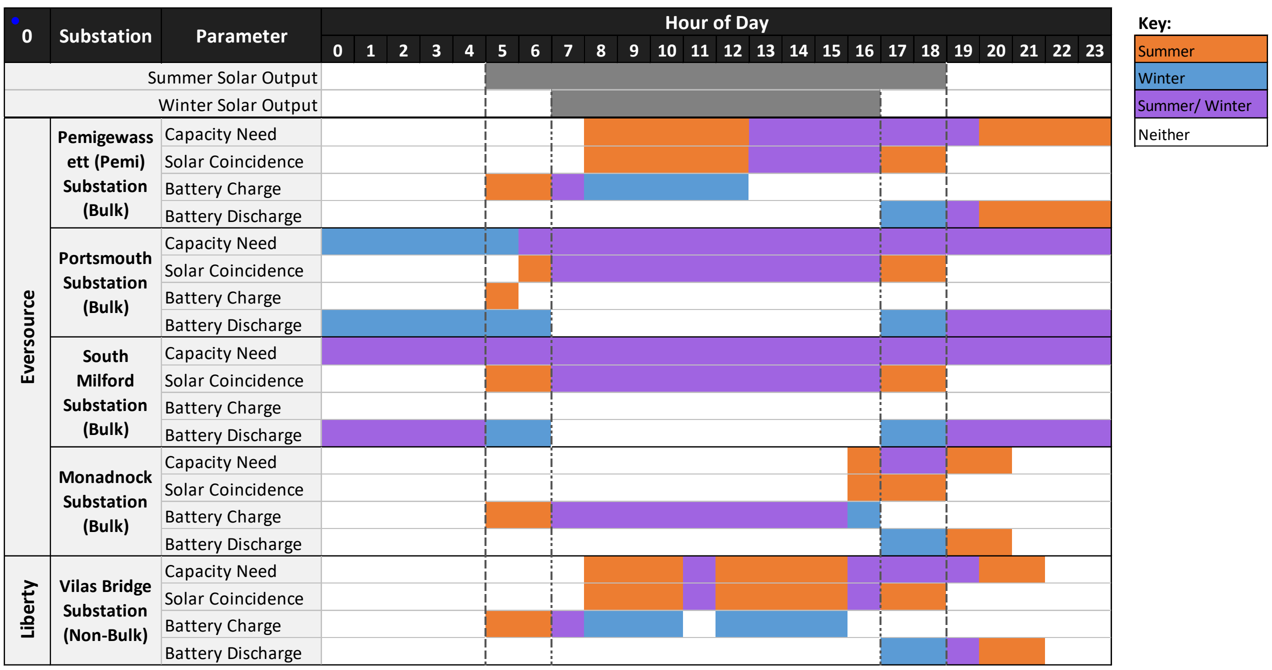
Source: Guidehouse, EDC data

High Level Mapping of DG and Capacity Deficiency Profiles

The load and DG profile analysis presented in the prior set of diagrams are simplified in Figure 66, which illustrates the hours during which solar PV production coincides with hours of capacity deficiency on peak days for the five locations where first year deficiencies occur during both summer and winter months. It also illustrates the hours during which solar PV production is available to charge battery storage devices and hours during which discharge of battery storage would enable alignment with more hours of capacity deficiency at times when solar production is zero.[52]

For example, the Pemi location has a summer peak day capacity deficiency between the hours of 7:00 a.m. and 11:00 p.m., and a winter peak day capacity deficiency between the hours of 12:00 p.m. and 7:00 p.m. Battery storage charging with solar energy production is available between 5:00 a.m. to 7:00 a.m. during summer and 6:00 a.m. through 12:00 p.m. in the winter.

Figure 66. Locations with Summer and Winter Peaks



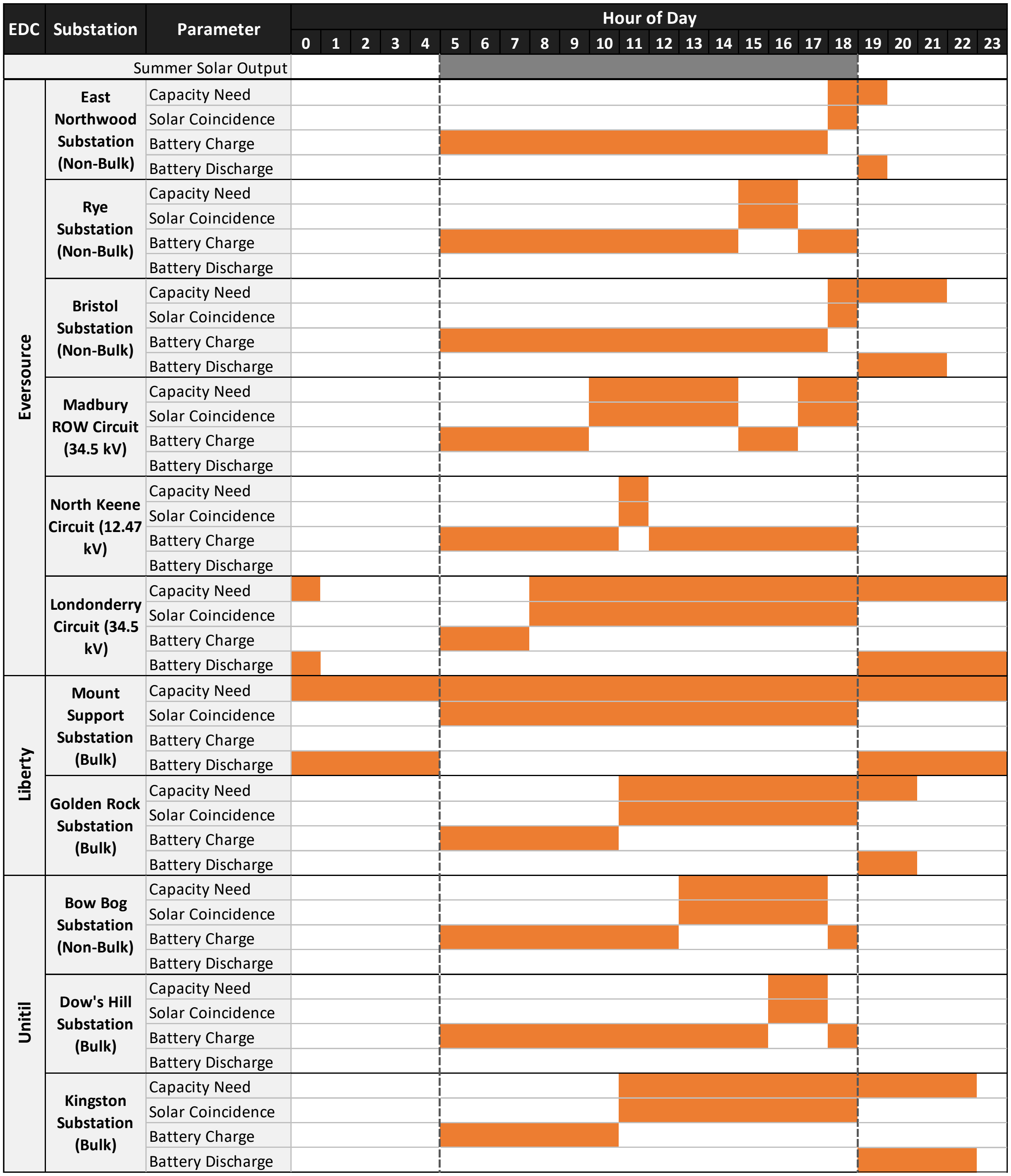
Source: Guidehouse, EDC data

Figure 67 is similar to Figure 66, but is less visually complex as it displays the remaining 11 locations, each of which are summer peaking only. Figure 67 indicates that several locations experience late afternoon or early evening peaks, such as the East Northwood and Bristol non-bulk substations. However, the duration of capacity deficiency is narrow

[52] Figure 64 excludes hydro production profiles as energy is produced for 24 hours, continuously throughout the days, for each season. Inclusion of hydro profiles would render the illustration unnecessarily complex.

at those two locations, along with other locations such as Dow Hill, leaving several hours of battery charging available from solar PV production.

Figure 67. Locations with Summer Peaks Only



Source: Guidehouse, EDC data

4.3.3 Methodology to Map Capacity Deficiency and DG Production Profiles (Example)

The methodology the study team applied to map and compare hourly capacity deficiencies to DG production profiles is described in the following steps. These steps describe how the normalized values that appear in Section 4.3.2 are derived and how actual values for a specific location (Pemi Bulk Substation) are derived and can be developed for other locations, including site-specific values for solar for different orientations.

1. The hourly capacity deficiencies measured in MW are derived for the summer and winter peak day during which the maximum capacity deficiency occurs. If there are no capacity deficiencies during the winter or summer season, only the season during which a capacity deficiency occurs is evaluated.
2. The hourly capacity deficiencies identified in Step 1 are normalized by converting the hourly load, measured in MW, to per unit values, where the hourly load during which the maximum capacity deficiency is equal to one, and all other hours are equal to the MW value during each hour divided by the maximum daily load measured in MW. Referring to Figure 55 and Table 24, per unit values are derived by subtracting the firm capacity represented by the dashed line (approximately 15 MW) from the actual hourly loads on peak days.[53] The maximum first-year capacity deficit in this instance is just above 8 MW.
3. The solar production values predicted to occur on the day of the summer and winter peak is derived via NREL's PVWatts solar model. The hourly solar production values are converted to per unit values using the approach described in Step 2 for hourly loads. The solar production profiles were derived based on the location listed in Figure 46 and that appear in Figure 51. The actual peak solar production during the summer using PVWatts is approximately 700 watts for a device with a rated output of 1,000 watts. However, location-specific profiles could be used in place of the single location presented in Figure 46. Similarly, different solar panel orientations and fixed versus rotating axis could be applied. The duration of the coincidence of solar production with hours of capacity deficiency in Figure 57 are 4 hours during the winter peak day, 11 during the summer.
4. The per-unit solar production profiles are superimposed on the per-unit hourly load profiles. The hours during which solar production coincides with hours of capacity deficiency are shaded (orange in the examples provided above). Figure 58 shows how the level and hours of coincidence change when a different orientation of a fixed axis solar array is chosen.

[53] Firm capacity is the lower of the seasonal normal (N-0) or contingency (N-1) rating of the line or substation.

5. For hours during which solar production is zero and where capacity deficiencies occur, energy storage is evaluated to determine the number of hours during which energy storage devices would need to be discharged to address capacity deficiencies. An assumption is made that energy storage charging must occur during hours when there are no capacity deficiencies. But solar production is greater than zero. Charging (dark blue) and discharge (light blue) hours are superimposed on the hourly chart. Figure 59 displays the number of available energy storage charge and discharge hours for winter and summer peak days.
6. The last step shows the alignment of hourly hydroelectric output, measured in per unit, over the entire day (Figure 60). The normalized hourly per-unit values for hydroelectric are based on site-specific actual production data instead of the proxy hourly values that are used for solar and solar paired with energy storage.

4.4 Summary: DG Production Profile Analysis

The potential for DG production to align with hours of capacity deficiency varies based on the selected location and duration of need.

- Solar PV production alone typically does not fully align with hours of capacity deficiencies in several locations analyzed, as a result of capacity deficiencies that occur during evening peak hours.
- Some of the locations analyzed have both summer and winter capacity deficiencies; the hours of need are not the same due to seasonal variations in load.
- Storage capacity, when paired with solar, improves the overall alignment of DG production with hours of locational capacity need.
- Hydroelectric production on average aligns with hours of capacity deficiencies, but at reduced production levels during the summer months when water flow is lower.

5.0 Conclusions

The study's findings are intended to inform the Commission of the potential value of locational capacity avoidance to better inform development of future NEM tariffs and related compensation rates for eligible DG technologies. The amount of DG and energy storage required to avoid capacity investments at specific locations, as typically performed in an NWS analysis, was not included as a part of this study. Instead, the study focuses on determination of the time-differentiated value of avoiding traditional capacity investments at selected locations through technology-agnostic load reduction. A related objective was to analyze the alignment of DG production profiles with locational load profiles and capacity deficiency hours for specific NEM-eligible DG technologies. Those technologies include solar PV, solar PV paired with energy storage, and hydroelectric generation, all with capacities rated up to 1 MW.

Based on the analysis in Sections 2.0 through 4.0, the study supports the following findings and conclusions:

- Out of 696 total potential locations, 122 distribution system substations or lines were identified as candidate locations for detailed analysis of capacity investment avoidance opportunities under base, low, and high load growth forecast scenarios. Of the 122 locations considered, 13 are historical and 109 are future, with 77 triggered only in the High Case during the study time horizon.
- The projected capacity deficiencies for the three EDCs beginning in 2020 total approximately 107 MW, increasing to 147 MW by 2029, under the base load forecast. Total capacity deficiencies in 2029 for the low load growth forecast are 63 MW and for the high load growth forecast are 317 MW. A substantial number of capacity deficiencies occur in 2020, the first year of the forward-looking period covered by the study, in large part due to recent changes in planning criteria implemented by Eversource.
- Of the 16 locations selected for detailed analysis, five are historical investments. Five of the 16 locations have first year capacity deficiencies that occur during both winter and summer months; the remaining 11 are summer peaking only.
- The cost of traditional distribution system investments to address capacity deficiencies at the selected locations, expressed in terms of a revenue requirement, ranges from less than $1 million to over $14 million. The total value of traditional capacity investments at the 16 selected locations is approximately $75 million.
- The economic value of capacity investment avoidance varies significantly among the 16 locations based on a theoretical analysis of capacity avoidance using the RECC approach. The maximum hourly economic value of capacity investment avoidance ranges from under $1 per kilowatt (kW) per hour to over $4,000 per kW per hour. The greatest driver for that variance is the total number of hours over which capacity deficiencies occur at a specific location. A lower value is generally indicative of a capacity deficiency that occurs over a large number of hours, while a higher value is generally indicative of a capacity deficiency that occurs during fewer hours.
- Related findings from the capacity deficiency analysis and evaluation of DG production profiles are summarized as follows:
  - The number of hours of capacity deficiency varies significantly by location, with some locations with fewer than 15 hours of deficiency per year, while other locations are capacity deficient for several thousand hours per year.
  - Most locations have capacity deficiencies during late afternoon or early evening hours. Solar PV production profiles do not fully align with those hours of capacity deficiency. Solar PV paired with energy storage typically can produce electricity during most or all hours during which there are locational capacity deficiencies.
  - Hydro production profiles typically align with hours of capacity deficiency, but with lower production during summer months as compared to winter months.

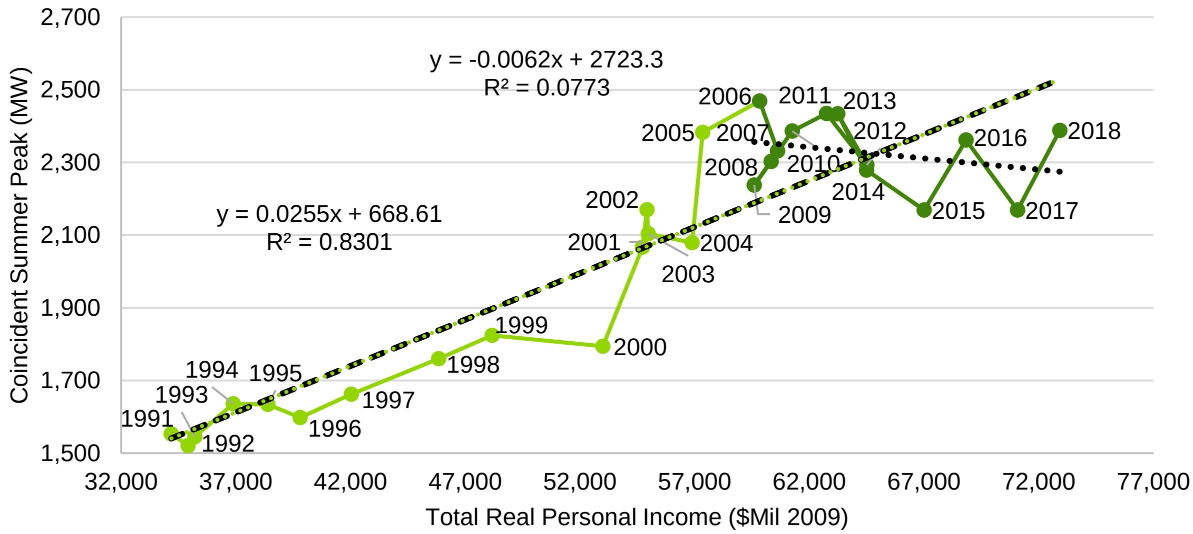
Appendix A. Detailed Methodology and Assumptions

A.1 Analysis of Economic Variables Impact on Load

Details of Analysis of Economic Factors on Peak Load:

Figure A-1 shows the New Hampshire summer peak in MW coincident with the ISO-NE peak compared with the total real personal income of New Hampshire from 1991 to 2018.[54] Given the inflection point in the coincident summer peak load in the 2006 where the increasing load no longer correlates with increasing total real personal income, the figure shows two trend lines. The first shows the trend line from 1991 to 2018 and the second shows the trend from 2006 to 2018.

Figure A-1. Coincident Summer Peak (MW) vs. Total Real Peal Income (1991-2018)

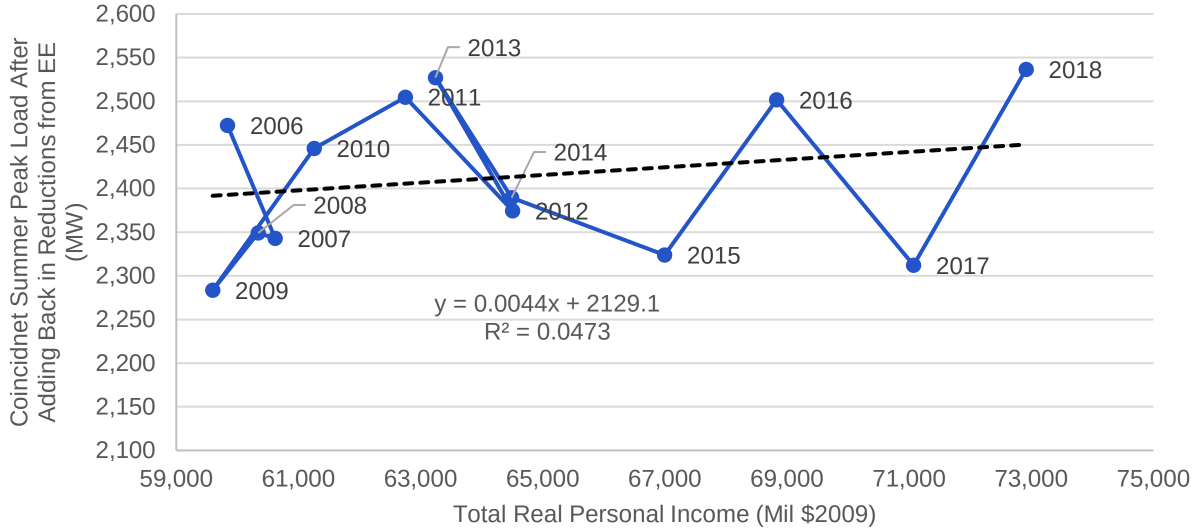


Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

Given the inflection point in the coincident summer peak load in 2006 where the increasing load no longer correlates with increasing total real personal income, the study reviews the more recent summer peaks and added back in the EE impacts that have reduced peak load. This analysis of summer peaks from 2006 to 2018, which removes the EE impacts on load reduction, is shown in Figure A-2. This figure shows a slightly upward trend as opposed to a minor downward trend in loading as relates to total real personal income, but the correlation is still poor.

[54] This analysis looked at the historic ISO-NE NH coincident summer peak since that is the value that is forecasted by ISO-NE forward for 10 years. The non-coincident summer peak did not vary significantly from the coincident peak for the historic period.

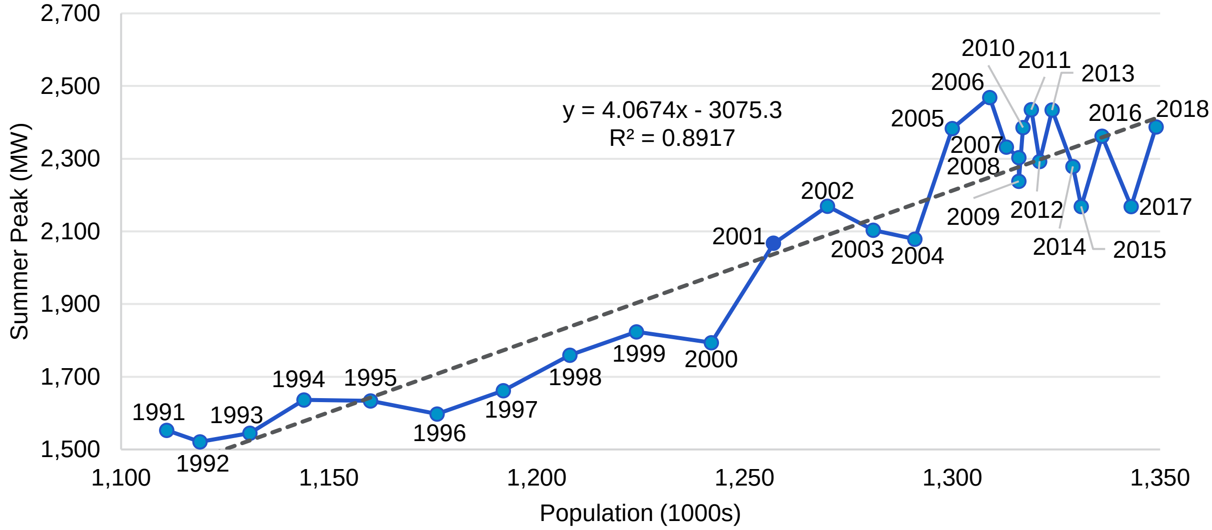
Figure A-2. Coincident Summer Peak After Adding Back in Peak Load Reductions from EE vs. Total Real Personal Income (2006-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

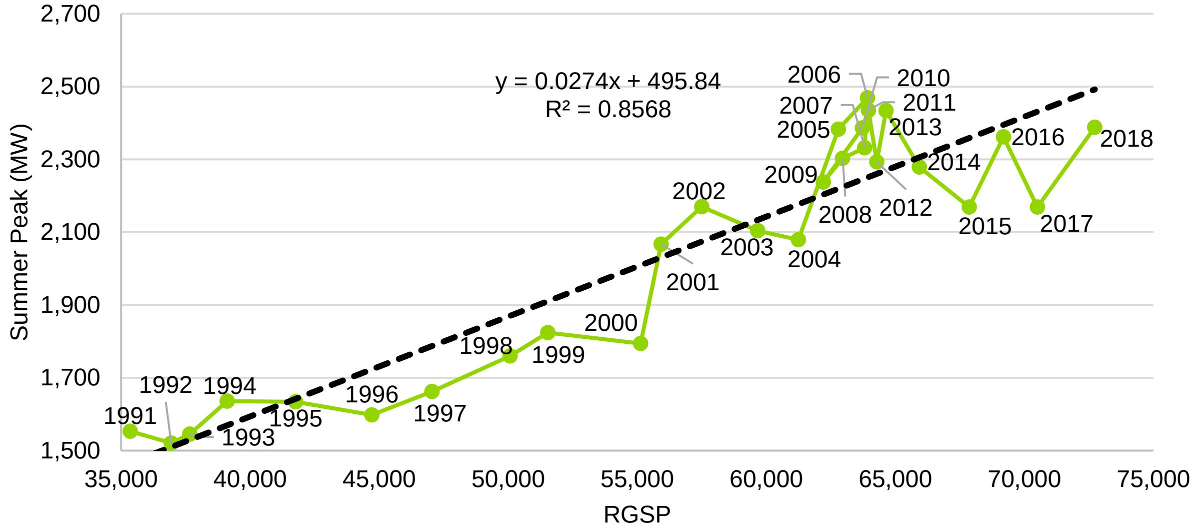
In addition to looking at the past 30 years and the past 12 years of summer peak as compared to total real personal income, the study also compared loading with total statewide population and real gross state product. The analysis revealed similar trends when considering total population and real gross state product as those seen with total real personal income. Additional metrics used for comparing coincident summer peak and economic factors are shown in Figure A-3 and Figure A-4.

Figure A-3. Coincident Summer Peak (MW) vs. Statewide Population (1991-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

Figure A-4. Coincident Summer Peak (MW) vs. Real Gross State Product (1991-2018)



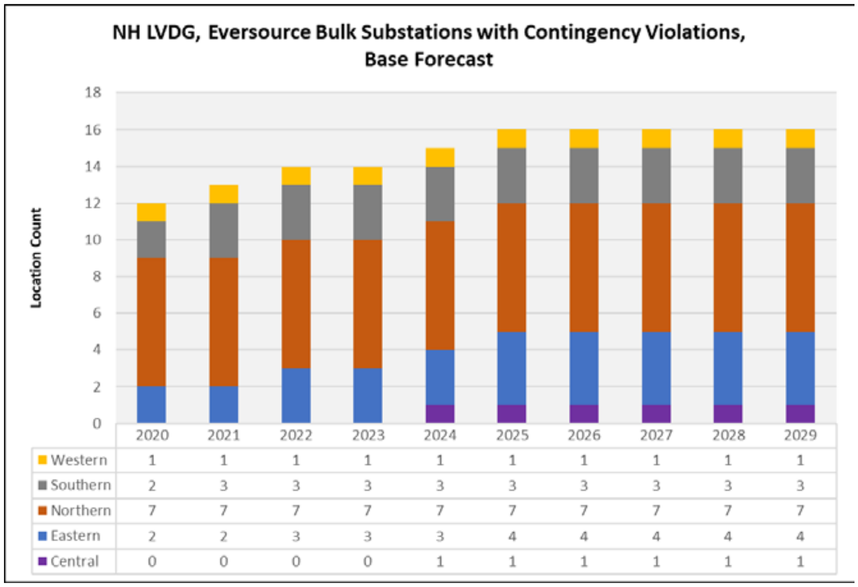
Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

A.2 Forward-Looking Violation Screening

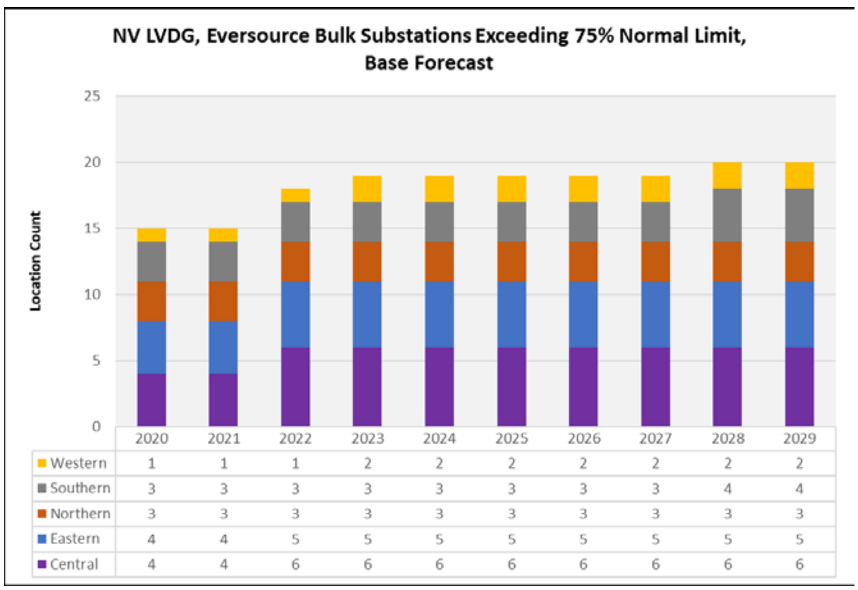
Capacity Deficiency Analysis: Eversource- Base Forecast

- In the base forecast Year 1, 12 substations do not meet Eversource's capacity planning criteria for contingencies (i.e., N-1 violations) and 15 bulk substations exceed 75% transformer normal limit rating[55]
- Six bulk substations have both normal and contingency violations during the 10-year forecast
- No violations occur on non-bulk substations
- Several near-term violations due to change in planning criteria for bulk substations

[55] Eversource recently changed their capacity planning criteria for bulk substations, which caused numerous near-term violations. Eversource's current capacity planning criteria is under review by the Commission.

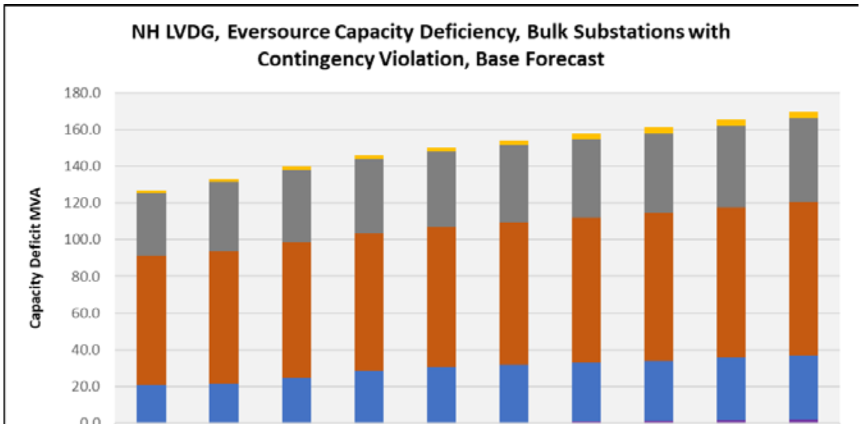


Source: Guidehouse, EDC data



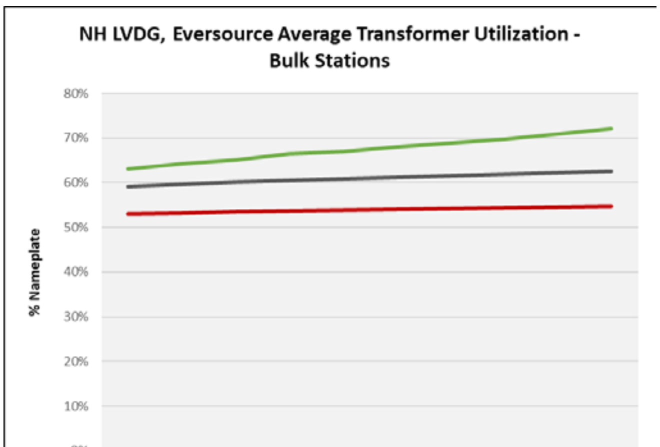
Source: Guidehouse, EDC data

- Approximately half of the total bulk substation capacity deficiencies are located in the northern region
- Capacity deficiencies are driven by bulk substations not meeting contingency (N-1) planning criteria rather than normal overloads caused by load growth
- Average bulk substations capacity utilization is 60% for the 10-year base load forecast



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	1.5	1.7	2.0	2.3	2.5	2.7	2.9	3.2	3.4	3.7
Southern	34.3	38.1	39.3	40.2	40.9	41.8	42.6	43.4	44.4	45.4
Northern	70.6	72.0	73.9	75.2	76.4	77.8	79.1	80.4	82.0	83.6
Eastern	20.6	21.5	24.7	28.3	30.3	31.1	32.0	32.9	34.0	35.0
Central	0.0	0.0	0.0	0.0	0.2	0.6	0.9	1.2	1.6	2.0

Source: Guidehouse, EDC data



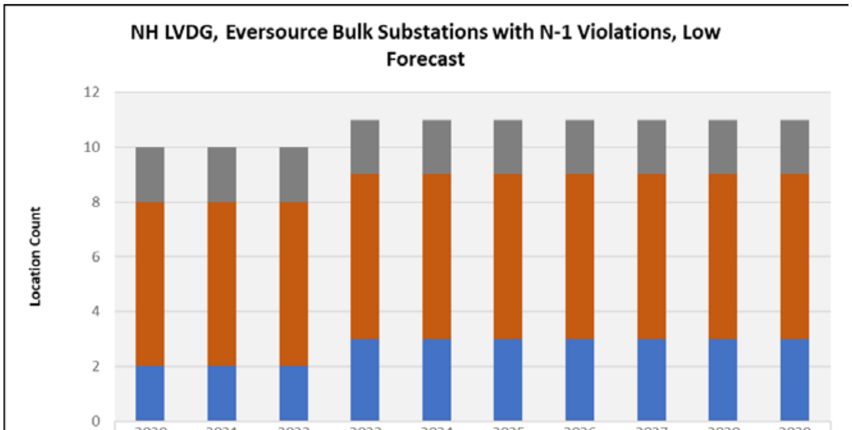
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base	59.19%	59.66%	60.16%	60.52%	60.83%	61.17%	61.48%	61.80%	62.15%	62.52%
Low	52.97%	53.22%	53.47%	53.64%	53.77%	53.96%	54.14%	54.35%	54.60%	54.66%
High	63.11%	64.25%	65.17%	66.49%	67.02%	67.97%	68.87%	69.64%	70.96%	72.16%

Base Low High

Source: Guidehouse, EDC data

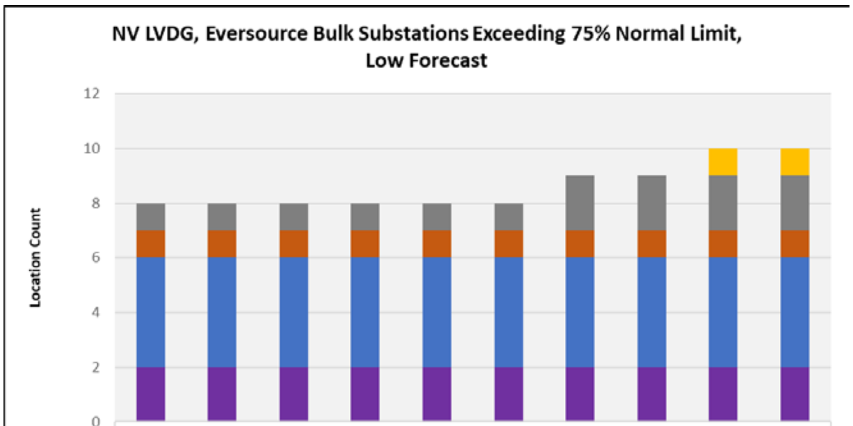
Capacity Deficiency Analysis: Eversource- Low Forecast

- Based on a low load forecast, the number of identified locations with N-1 contingency violations and normal limit violations drops to 10 and 8, respectively
- Number of bulk substations with both normal and contingency violations is two through 2022 and increases to three thereafter
- No violations occur on non-bulk substations



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0	0	0	0	0	0	0	0	0	0
Southern	2	2	2	2	2	2	2	2	2	2
Northern	6	6	6	6	6	6	6	6	6	6
Eastern	2	2	2	3	3	3	3	3	3	3
Central	0	0	0	0	0	0	0	0	0	0

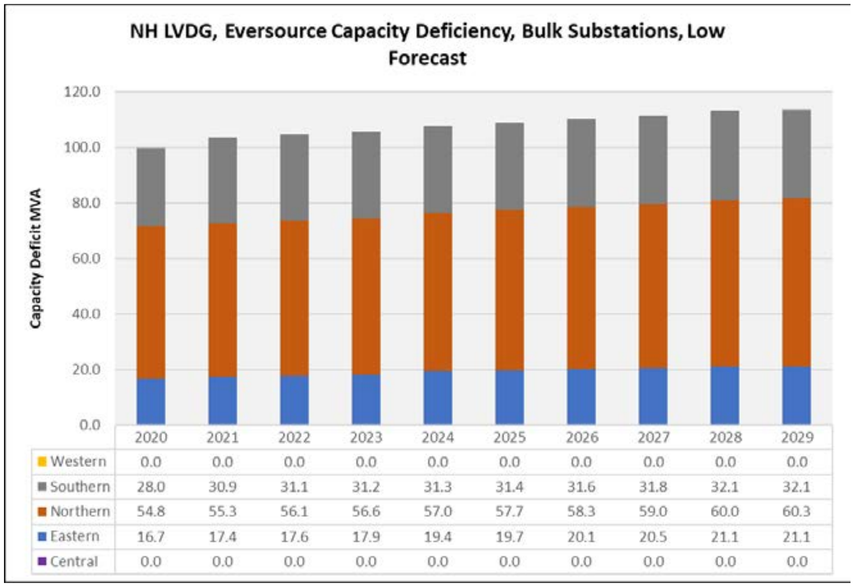
Source: Guidehouse, EDC data



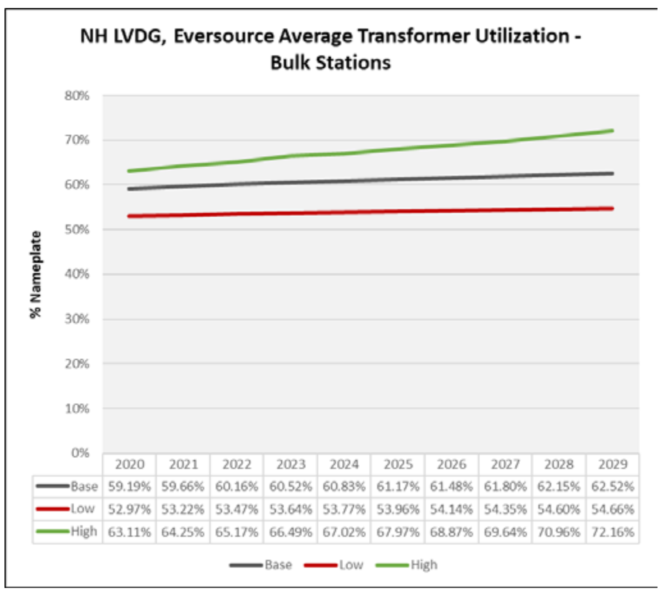
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0	0	0	0	0	0	0	0	1	1
Southern	1	1	1	1	1	1	2	2	2	2
Northern	1	1	1	1	1	1	1	1	1	1
Eastern	4	4	4	4	4	4	4	4	4	4
Central	2	2	2	2	2	2	2	2	2	2

Source: Guidehouse, EDC data

- The low load forecast does not materially decrease the number of bulk substations with contingency violations
- Approximately 14 MVA of capacity deficiency growth in the 10-year period
- In Year 10, 10-year capacity deficiencies drop from about 170 MVA to 110 MVA
- Average substation capacity utilization drops from 60% to 54% for the 10-year low forecast



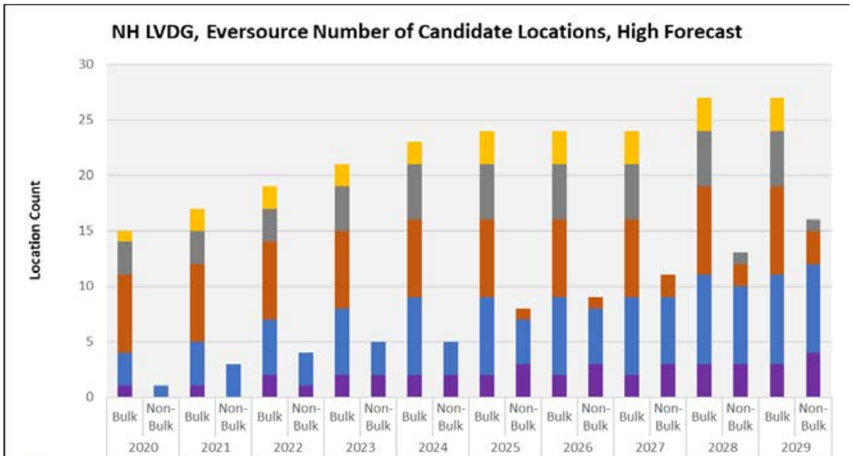
Source: Guidehouse, EDC data



Source: Guidehouse, EDC data

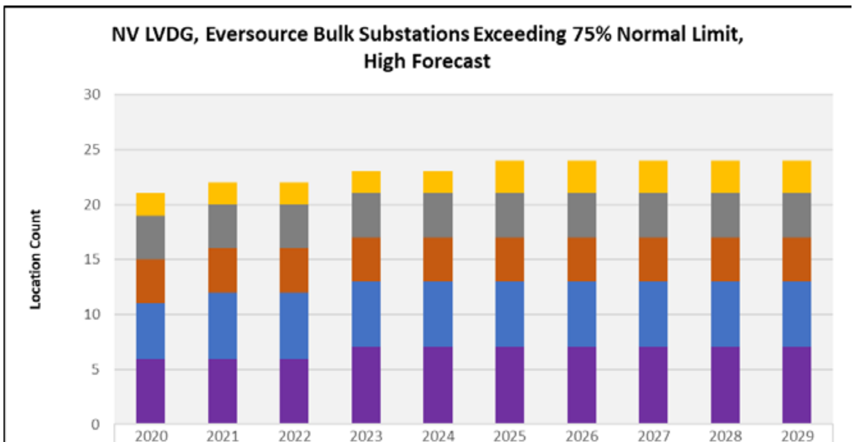
Capacity Deficiency Analysis: Eversource- High Forecast

- Identified locations with capacity deficiencies include bulk and non-bulk substations for the high load forecast case
- By Year 10, approximately 50% of bulk substations and 20% of non-bulk substations experience violations (e.g., potential candidate substations for capacity investment avoidance)
- Eastern region non-bulk substations impacted the most by high forecast



	2020 Bulk	2020 Non-Bulk	2021 Bulk	2021 Non-Bulk	2022 Bulk	2022 Non-Bulk	2023 Bulk	2023 Non-Bulk	2024 Bulk	2024 Non-Bulk	2025 Bulk	2025 Non-Bulk	2026 Bulk	2026 Non-Bulk	2027 Bulk	2027 Non-Bulk	2028 Bulk	2028 Non-Bulk	2029 Bulk	2029 Non-Bulk
Western	1	0	2	0	2	0	2	0	2	0	3	0	3	0	3	0	3	0	3	0
Southern	3	0	3	0	3	0	4	0	5	0	5	0	5	0	5	0	5	1	5	1
Northern	7	0	7	0	7	0	7	0	7	0	7	1	7	1	7	2	8	2	8	3
Eastern	3	1	4	3	5	3	6	3	7	3	7	4	7	5	7	6	8	7	8	8
Central	1	0	1	0	2	1	2	2	2	2	2	3	2	3	2	3	3	3	3	4

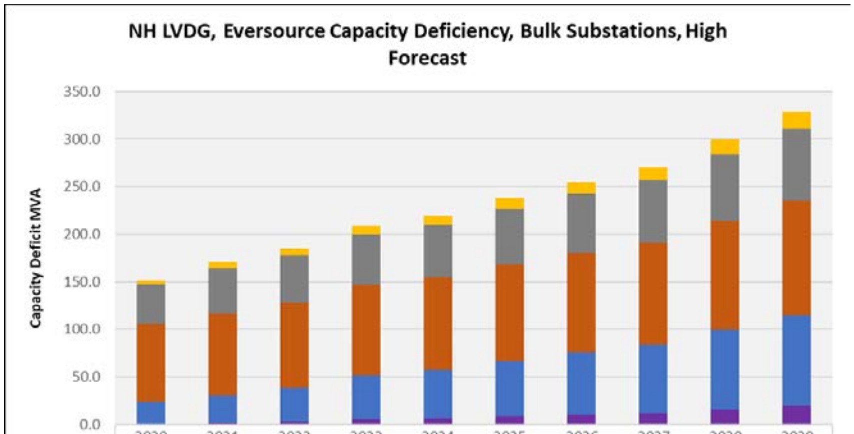
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	2	2	2	2	2	3	3	3	3	3
Southern	4	4	4	4	4	4	4	4	4	4
Northern	4	4	4	4	4	4	4	4	4	4
Eastern	5	6	6	6	6	6	6	6	6	6
Central	6	6	6	7	7	7	7	7	7	7

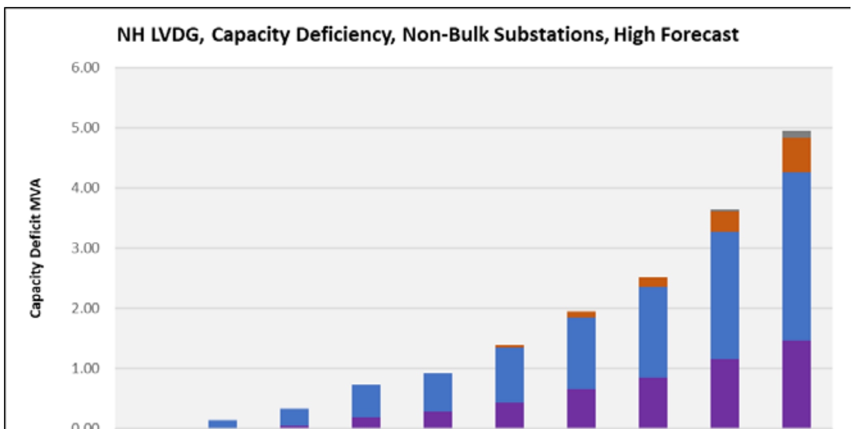
Source: Guidehouse, EDC data

- The number of and magnitude of substation capacity deficiencies increase significantly for the high load forecast case
- Total capacity deficiency doubles in the 10-year period (over 300 MVA in 2029)
- Highest capacity deficiency growth rates in western and eastern regions bulk substations



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	4.1	6.9	7.8	9.1	9.6	10.8	12.4	13.7	16.1	18.2
Southern	41.3	47.3	49.7	53.5	55.2	58.9	62.4	65.3	70.4	74.9
Northern	82.1	86.2	89.7	94.9	96.9	100.7	104.3	107.3	114.3	120.6
Eastern	23.5	29.0	35.5	46.1	51.1	58.8	65.7	71.9	83.3	94.8
Central	0.6	1.5	2.8	5.5	6.5	8.5	10.3	11.8	15.8	20.3

Source: Guidehouse, EDC data

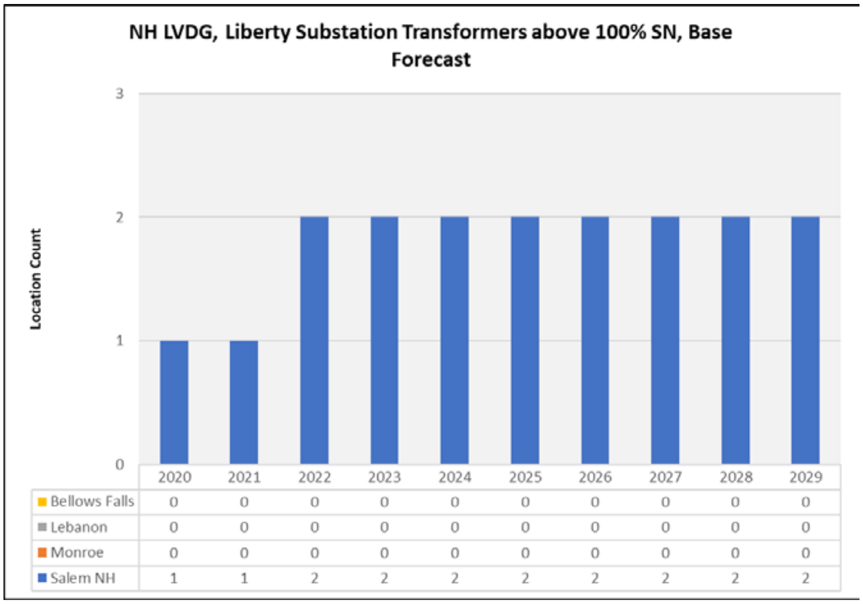


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Southern	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.12
Northern	0.00	0.00	0.00	0.00	0.00	0.05	0.10	0.15	0.35	0.58
Eastern	0.02	0.14	0.28	0.53	0.65	0.91	1.20	1.51	2.12	2.79
Central	0.00	0.00	0.05	0.19	0.27	0.43	0.65	0.84	1.15	1.46

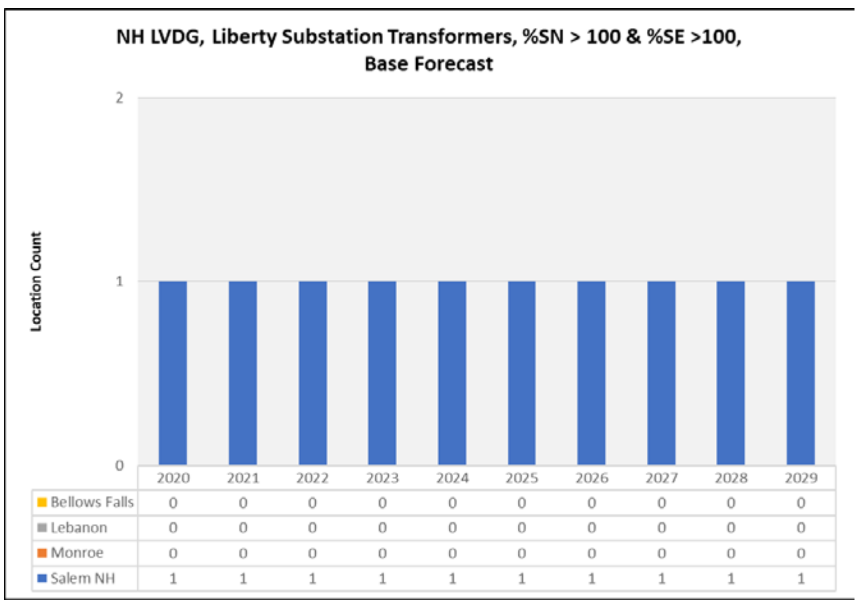
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty- Base Forecast

- Over the 10-year period, one transformer exceeds 100% normal rating in the first 2 years and an additional transformer starting in 2022
- One substation transformer exceeds 100% normal and 100% emergency ratings through 2029

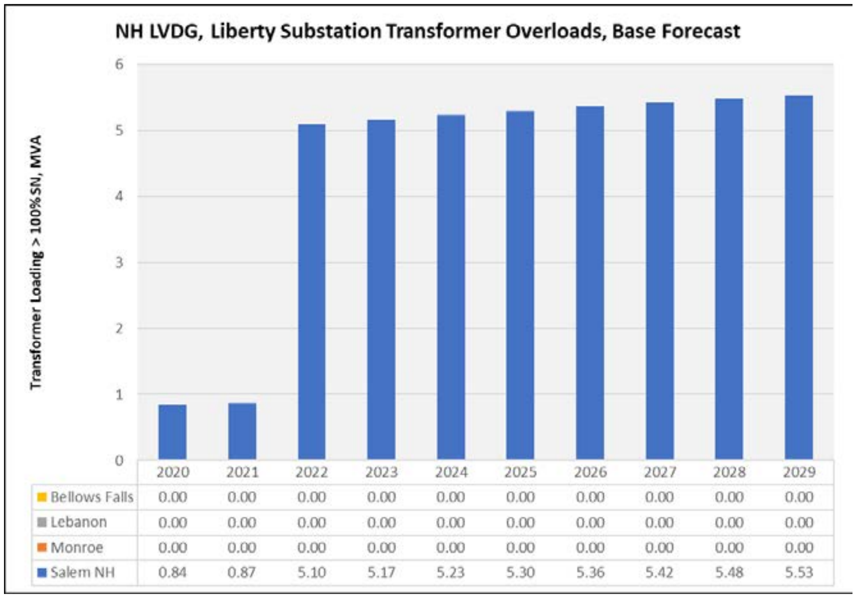


Source: Guidehouse, EDC data

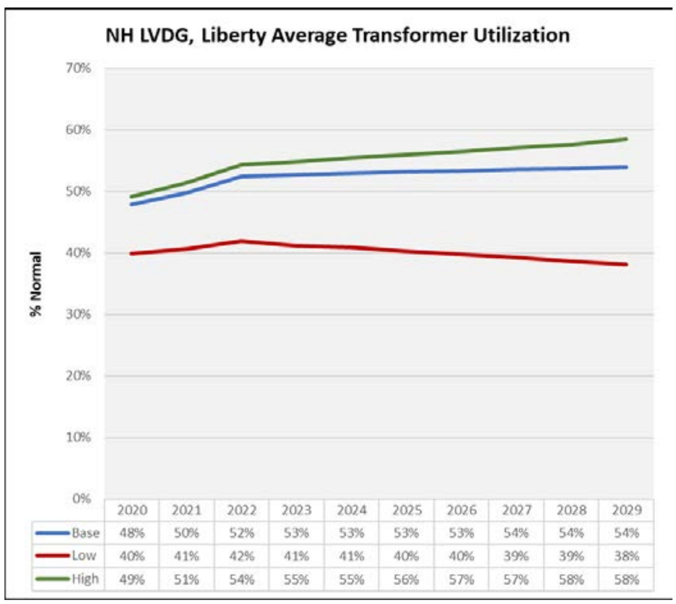


Source: Guidehouse, EDC data

- For the base load forecast, capacity deficiency growth in the 10-year period is approximately 5 MVA
- Capacity deficiency growth in the 10-year period only observed in the Salem area
- Average substations capacity utilization is 52% for the 10-year base load forecast



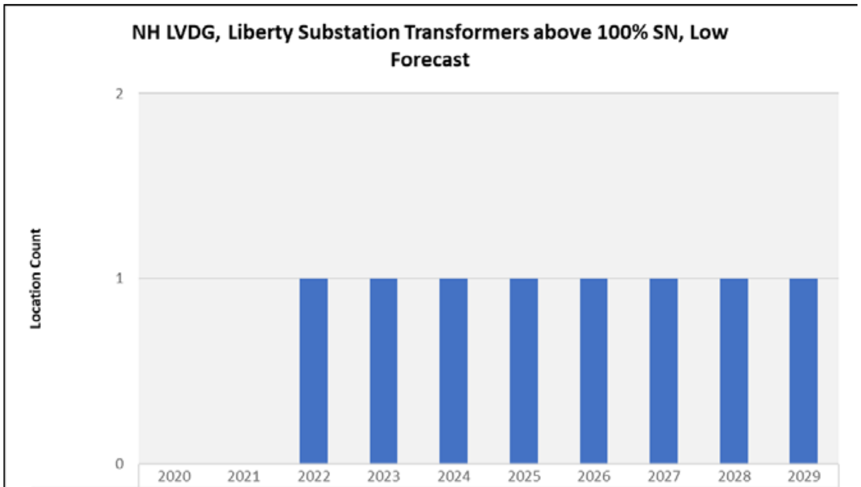
Source: Guidehouse, EDC data



Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty - Low Forecast

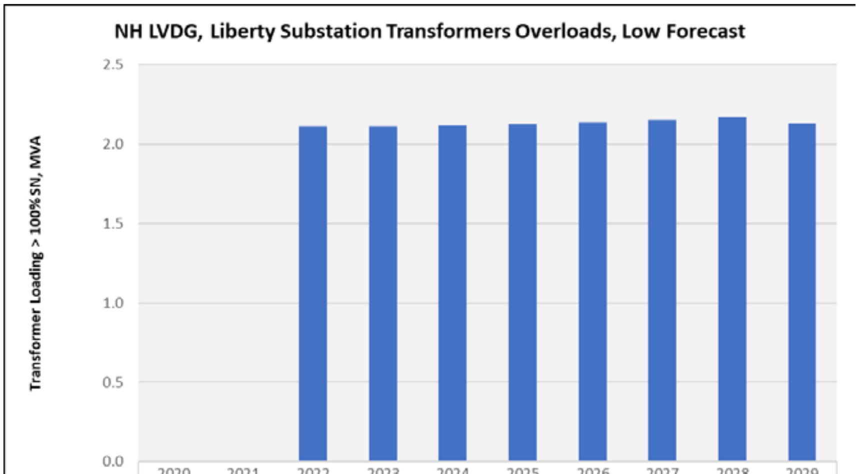
- For the low load forecast, one substation transformer exceeds 100% normal ratings starting in 2022
- None of the substation transformers exceed both 100% normal and 100% emergency ratings



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0	0	0	0	0	0	0	0	0	0
Lebanon	0	0	0	0	0	0	0	0	0	0
Monroe	0	0	0	0	0	0	0	0	0	0
Salem NH	0	0	1	1	1	1	1	1	1	1

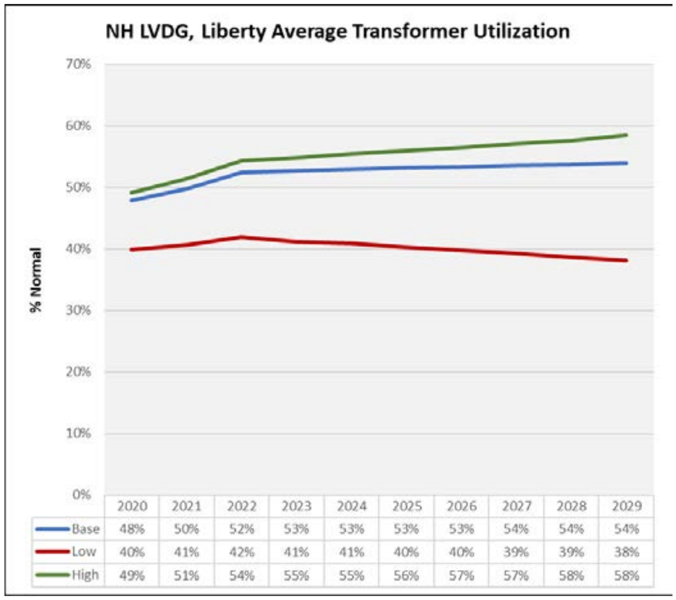
Source: Guidehouse, EDC data

- For the low forecast, the projected capacity deficiency growth remains constant for last eight years
- Approximately 2 MVA of capacity deficiency per year from 2022 to 2029
- Average substation capacity utilization drops from 52% to 40% for the 10-year low forecast



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Bellows Falls	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lebanon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Monroe	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Salem NH	0.00	0.00	2.11	2.11	2.12	2.13	2.14	2.15	2.17	2.13

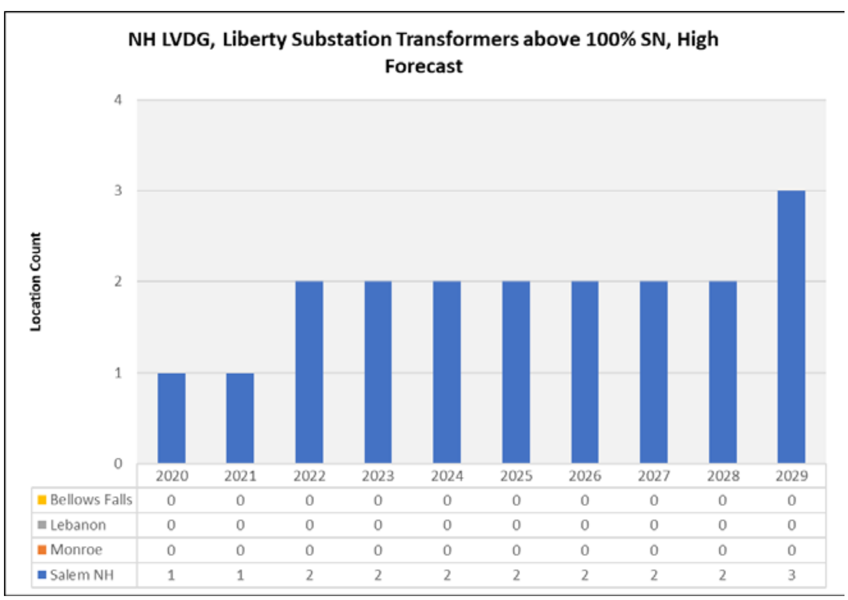
Source: Guidehouse, EDC data



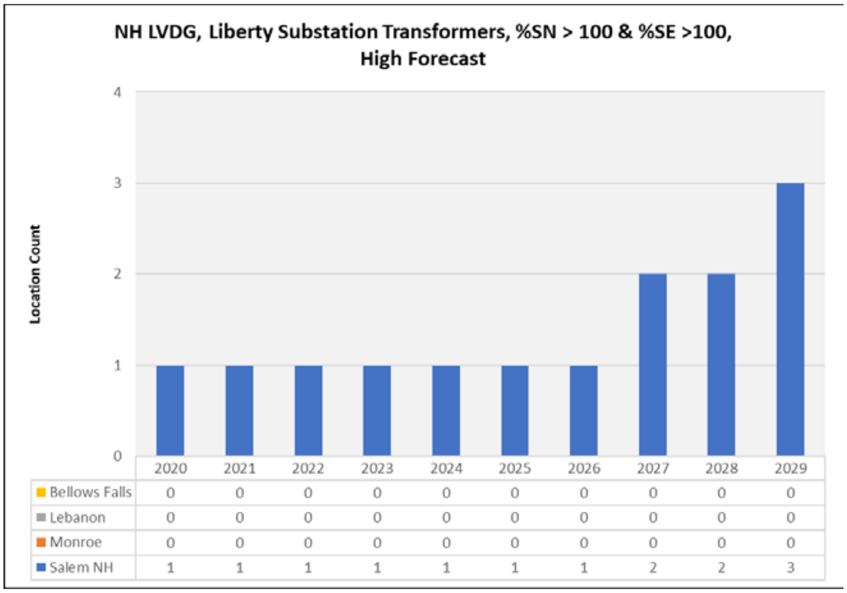
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty- High Forecast

- For the high forecast, two substations exceed 100% normal ratings and two substations exceed both 100% normal and 100% emergency ratings
- For the 10-year period, one transformer exceeds 100% normal ratings in the first 2 years, an additional transformer in 2022, and a third transformer in 2029
- For the 10-year period, one transformer exceeds 100% normal and 100% emergency ratings in the first 7 years, an additional transformer in 2027, and a third transformer in 2029

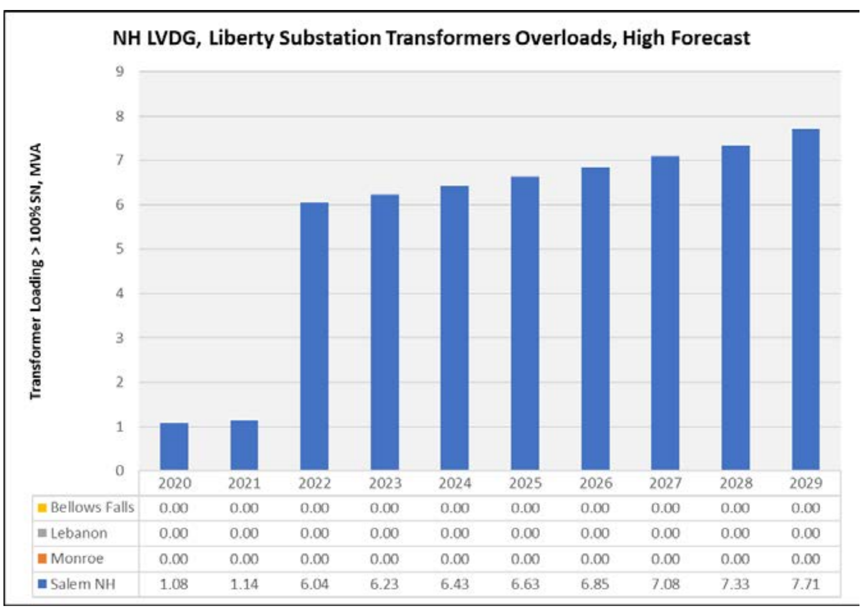


Source: Guidehouse, EDC data

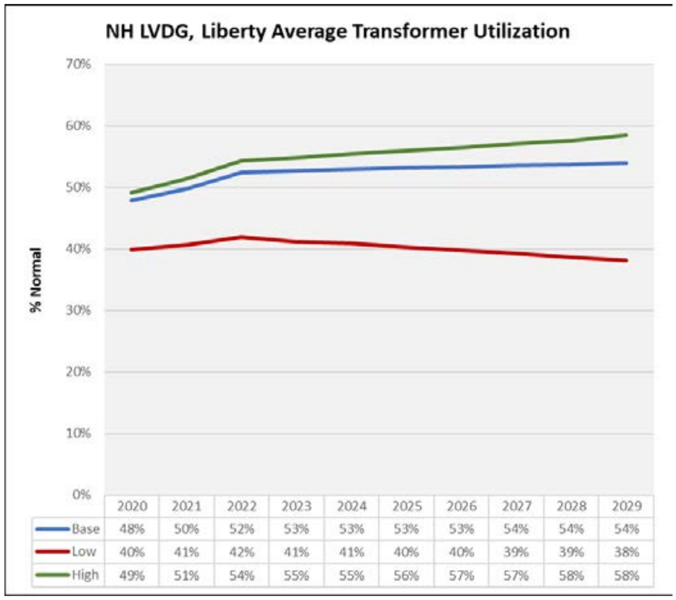


Source: Guidehouse, EDC data

- For the high load forecast, capacity deficiency growth in the 10-year period increases to approximately 7 MVA
- Approximately a 10% increase in average transformer utilization in the 10-year period



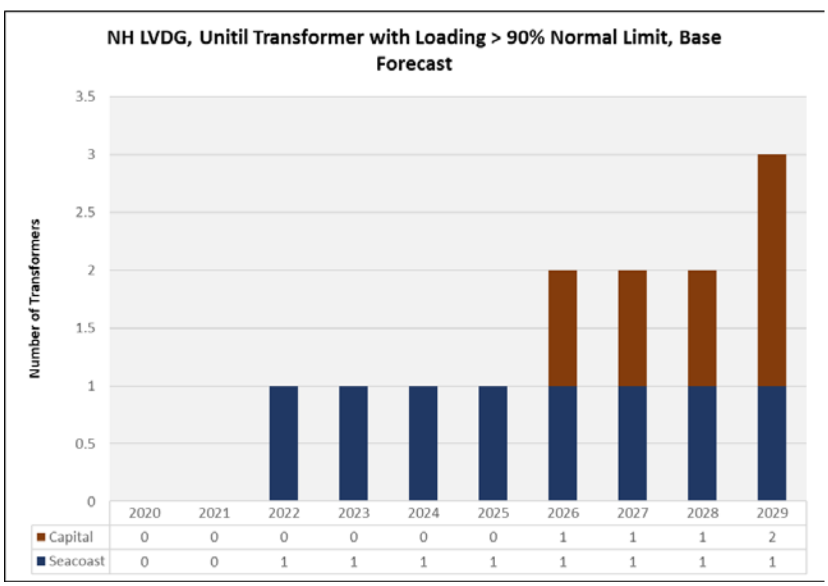
Source: Guidehouse, EDC data



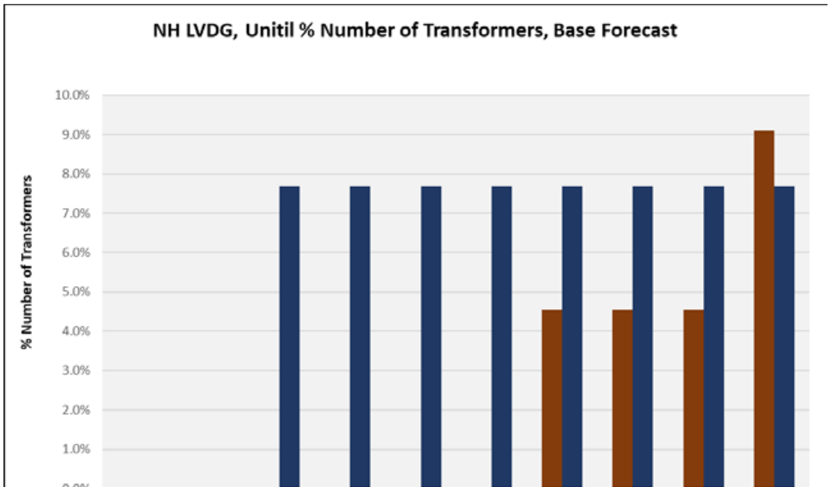
Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Unitil - Base Forecast

- For the base load forecast, three substation transformers in the capital and seacoast regions exceed Unitil's 90% normal loading criteria by 2029
- Seacoast and capital regions have a single substation transformer above 90% normal limit starting in 2022 and 2026, respectively
- Capital region has one additional transformer above the 90% normal limit in 2029



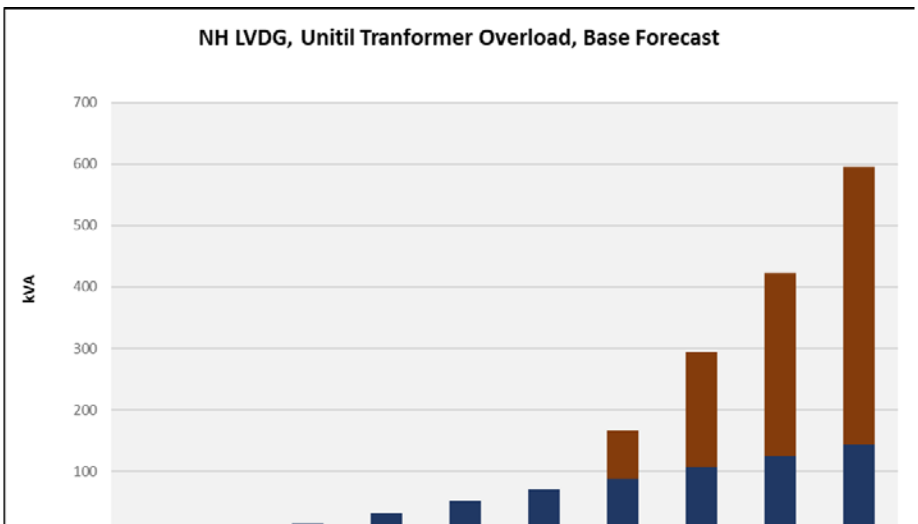
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.5%	4.5%	4.5%	9.1%
Seacoast	0.0%	0.0%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%

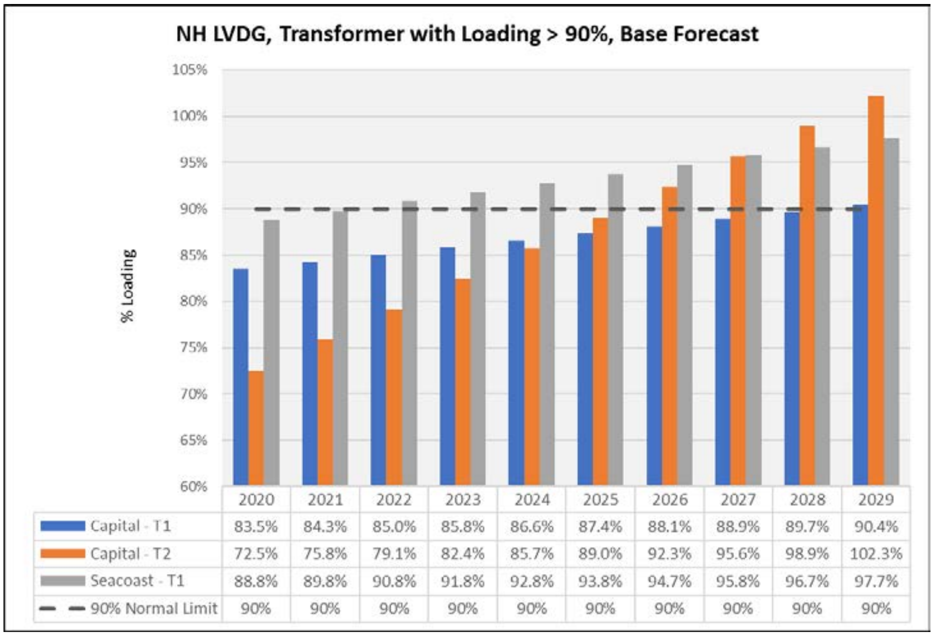
Source: Guidehouse, EDC data

- Three substation transformers exceed Unitil's 90% criteria for normal loading limit for the 10-year base load forecast
- Two transformers in the capital region
- One transformer in the seacoast region



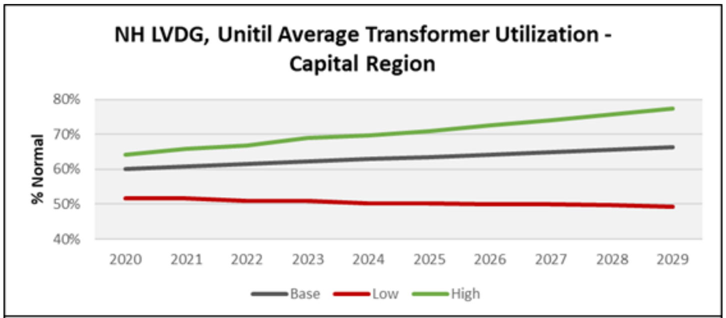
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0	0	0	0	0	0	78	188	298	453
Seacoast	0	0	15	33	52	70	88	107	125	143

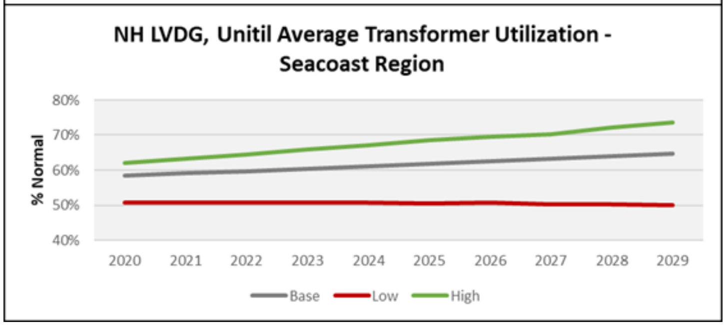
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital - T1	83.5%	84.3%	85.0%	85.8%	86.6%	87.4%	88.1%	88.9%	89.7%	90.4%
Capital - T2	72.5%	75.8%	79.1%	82.4%	85.7%	89.0%	92.3%	95.6%	98.9%	102.3%
Seacoast - T1	88.8%	89.8%	90.8%	91.8%	92.8%	93.8%	94.7%	95.8%	96.7%	97.7%
90% Normal Limit	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%

Source: Guidehouse, EDC data

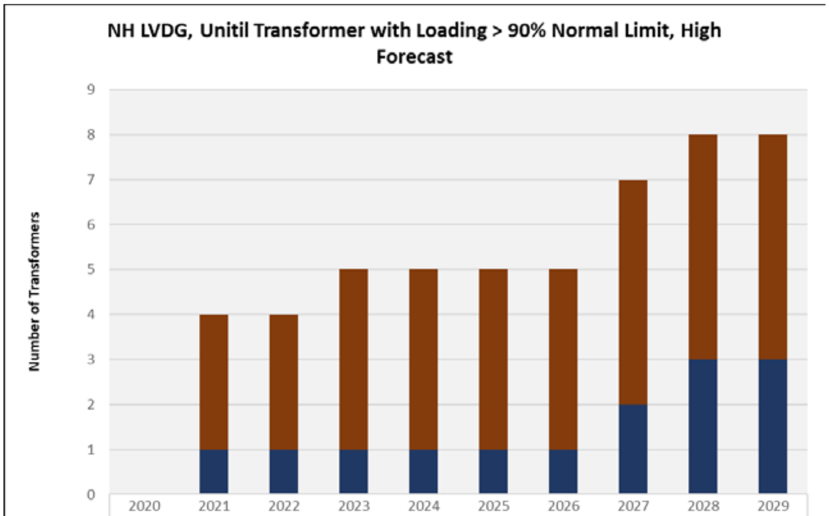




Source: Guidehouse, EDC data

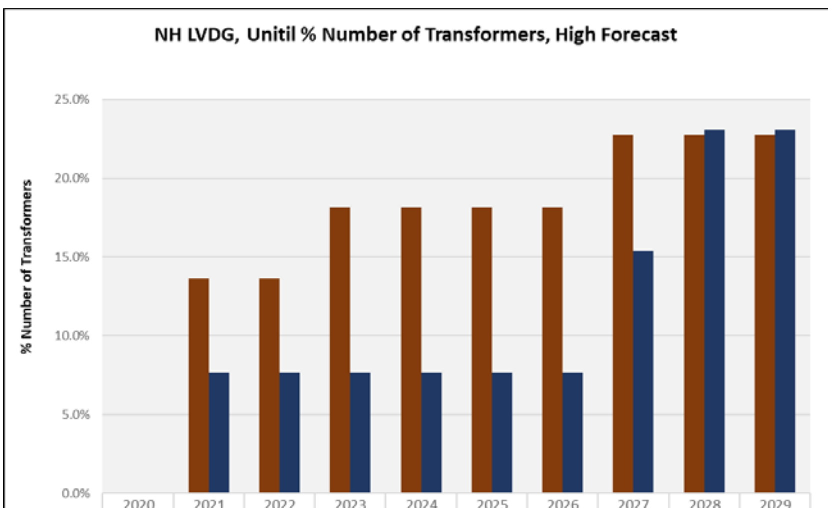
Capacity Deficiency Analysis: Unitil- High Forecast

- There are no violations on substation transformers for the low forecast case; however, five violations occur for the high forecast case
- Most additional violations occur in later years



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0	3	3	4	4	4	4	5	5	5
Seacoast	0	1	1	1	1	1	1	2	3	3

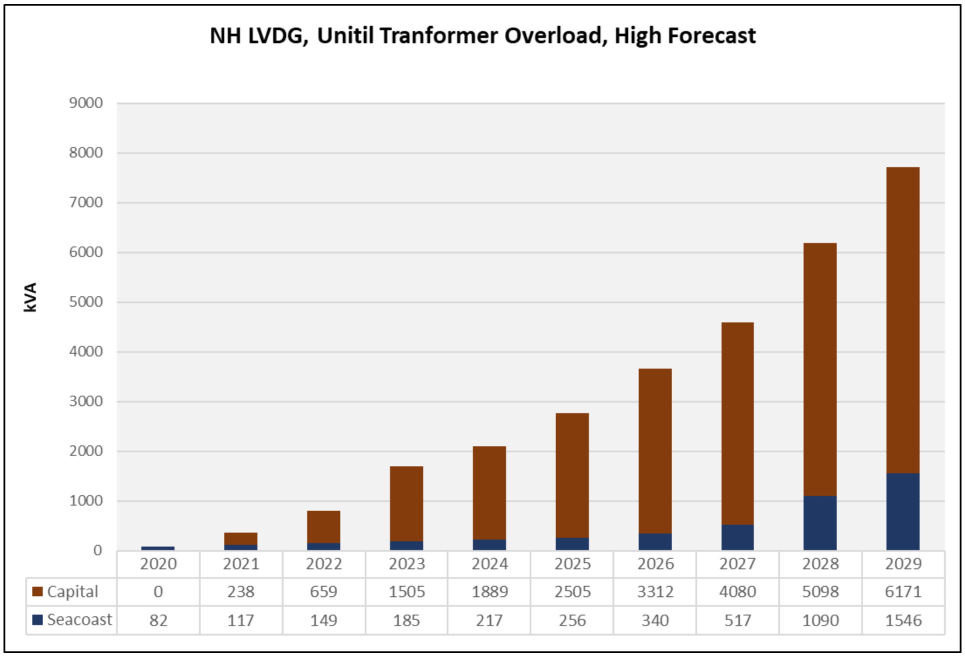
Source: Guidehouse, EDC data



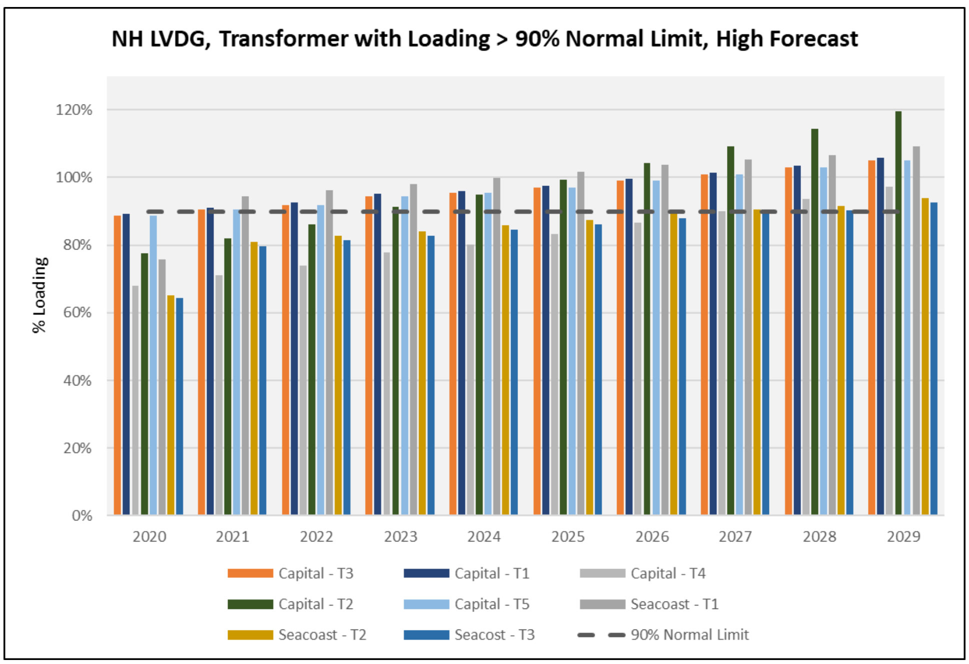
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0.0%	13.6%	13.6%	18.2%	18.2%	18.2%	18.2%	22.7%	22.7%	22.7%
Seacoast	0.0%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	15.4%	23.1%	23.1%

Source: Guidehouse, EDC data

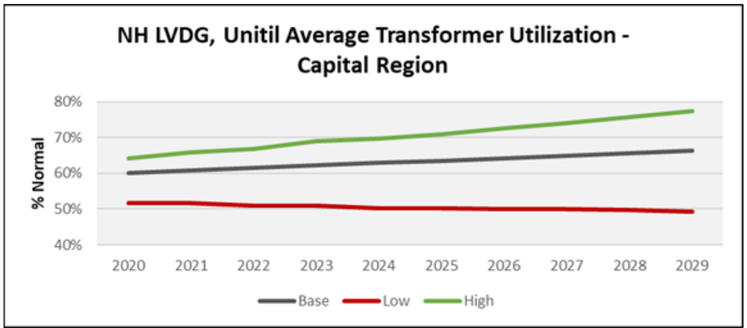
- Eight substation transformers exceed Unitil’s 90% normal loading limit for the 10-year high forecast case
- Transformer loadings increase significantly for High Case

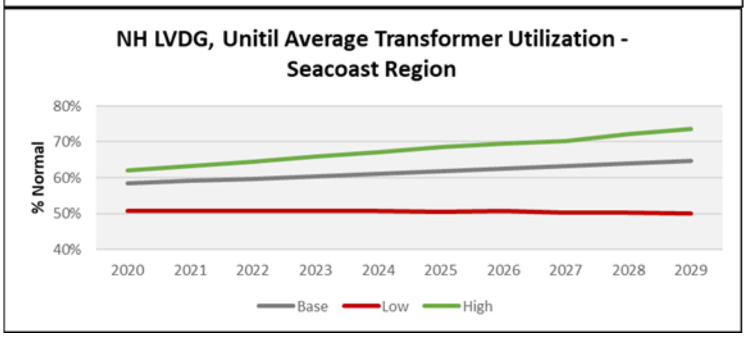


Source: Guidehouse, EDC data



Source: Guidehouse, EDC data





Source: Guidehouse, EDC data

Appendix B. Forward-Looking Capacity Deficiencies by Location

Table B-1. Complete List of Capacity Deficiencies by Location

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
1	Eversource	Bulk Substation	Ashland		Northern	34.5	Low	2020	N-1, 75% Tx Capacity
2	Eversource	Bulk Substation	Bedford		Central	34.5	High	2020	75% Tx Capacity
3	Eversource	Bulk Substation	Beebe River		Northern	34.5	Low	2020	N-1
4	Eversource	Bulk Substation	Brentwood		Eastern	34.5	High	2022	N-1
5	Eversource	Bulk Substation	Bridge St. 34.5kv		Southern	34.5	High	2021	75% Tx Capacity
6	Eversource	Bulk Substation	Bridge St. 4kv		Southern	4.16	Low	2020	N-1, 75% Tx Capacity
7	Eversource	Bulk Substation	Chestnut Hill		Western	34.5	Base	2020	N-1, 75% Tx Capacity
8	Eversource	Bulk Substation	Dover		Eastern	34.5	Low	2020	N-1, 75% Tx Capacity
9	Eversource	Bulk Substation	Eddy		Central	34.5	Base	2020	75% Tx Capacity
10	Eversource	Bulk Substation	Great Bay		Eastern	34.5	Low	2020	N-1, 75% Tx Capacity
11	Eversource	Bulk Substation	Huse Road		Central	34.5	Low	2020	N-1, 75% Tx Capacity
12	Eversource	Bulk Substation	Laconia		Northern	34.5	Base	2020	N-1, 75% Tx Capacity
13	Eversource	Bulk Substation	Lawrence Road		Southern	34.5	Base	2020	N-1
14	Eversource	Bulk Substation	Long Hill		Southern	34.5	Base	2020	75% Tx Capacity
15	Eversource	Bulk Substation	Madbury		Eastern	34.5	Low	2020	75% Tx Capacity
16	Eversource	Bulk Substation	Mill Pond		Eastern	12.47	Low	2020	N-1
17	Eversource	Bulk Substation	Monadnock		Western	34.5	Base	2020	N-1, 75% Tx Capacity
18	Eversource	Bulk Substation	North Woodstock		Northern	34.5	Low	2020	N-1
19	Eversource	Bulk Substation	North Keene		Western	12.47	High	2022	N-1, 75% Tx Capacity
20	Eversource	Bulk Substation	Oak Hill		Central	34.5	High	2020	75% Tx Capacity

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
21	Eversource	Bulk Substation	Pemigewasset		Northern	34.5	Low	2020	N-1, 75% Tx Capacity
22	Eversource	Bulk Substation	Pine Hill		Central	34.5	High	2026	75% Tx Capacity
23	Eversource	Bulk Substation	Portsmouth		Eastern	34.5	Low	2020	N-1, 75% Tx Capacity
24	Eversource	Bulk Substation	Reeds Ferry		Central	34.5	Low	2020	N-1, 75% Tx Capacity
25	Eversource	Bulk Substation	Resistance		Eastern	34.5	Low	2020	N-1
26	Eversource	Bulk Substation	Rimmon		Central	34.5	Base	2020	75% Tx Capacity
27	Eversource	Bulk Substation	Rochester		Eastern	34.5	High	2020	75% Tx Capacity
28	Eversource	Bulk Substation	Saco Valley		Northern	34.5	Low	2020	N-1
29	Eversource	Bulk Substation	South Milford		Southern	34.5	Low	2020	N-1, 75% Tx Capacity
30	Eversource	Bulk Substation	Tasker Farm		Eastern	34.5	High	2027	N-1, 75% Tx Capacity
31	Eversource	Bulk Substation	Thornton		Southern	34.5	High	2029	N-1
32	Eversource	Bulk Substation	Weare		Central	34.5	High	2021	N-1
33	Eversource	Bulk Substation	White Lake		Northern	34.5	Low	2020	N-1, 75% Tx Capacity
34	Eversource	Bulk Substation	Whitefield		Northern	34.5	Base	2020	N-1
35	Eversource	Non-Bulk Substation	Cutts Street		Eastern	12.47	High	2027	LTE
36	Eversource	Non-Bulk Substation	East Northwood		Eastern	12.47	High	2021	LTE
37	Eversource	Non-Bulk Substation	Hanover Street		Central	12.47	High	2024	LTE
38	Eversource	Non-Bulk Substation	Long Hill		Southern	12.47	High	2029	LTE
39	Eversource	Non-Bulk Substation	Loudon		Northern	12.47	High	2028	LTE
40	Eversource	Non-Bulk Substation	Loudon		Northern	12.47	High	2025	LTE
41	Eversource	Non-Bulk Substation	Meetinghouse Road		Central	12.47	High	2022	LTE
42	Eversource	Non-Bulk Substation	North Hampton		Eastern	4.16	High	2028	LTE
43	Eversource	Non-Bulk Substation	Portland Street		Eastern	12.47	High	2025	LTE
44	Eversource	Non-Bulk Substation	Portland Street		Eastern	12.47	High	2029	LTE
45	Eversource	Non-Bulk Substation	Rye		Eastern	4.16	High	2022	LTE

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
46	Eversource	Non-Bulk Substation	Salmon Falls		Eastern	4.16	High	2022	LTE
47	Eversource	Non-Bulk Substation	Stark Avenue		Eastern	4.16	High	2027	LTE
48	Eversource	Non-Bulk Substation	Suncook		Central	12.47	High	2026	LTE
49	Eversource	Non-Bulk Substation	Warner		Central	4.16	High	2029	LTE
50	Eversource	34.5 kV Circuits	371_62	Cocheco Street	Eastern	34.5	High	2025	Normal
51	Eversource	34.5 kV Circuits	3137X_65	Madbury	Eastern	34.5	High	2020	Normal
52	Eversource	34.5 kV Circuits	380_65	Madbury	Eastern	34.5	Base	2020	Normal
53	Eversource	34.5 kV Circuits	314_22	South Milford	Southern	34.5	High	2028	Normal
54	Eversource	Non-34.5 kV distribution circuits	15W4_63	Cutts Street	Eastern	12.47	High	2028	Normal
55	Eversource	Non-34.5 kV distribution circuits	16H3_21	Edgeville	Southern	4.16	High	2026	Normal
56	Eversource	Non-34.5 kV distribution circuits	2W2_41	Lochmere	Northern	12.47	Low	2020	Normal
57	Eversource	Non-34.5 kV distribution circuits	40W1_21	Long Hill	Southern	12.47	High	2022	Normal
58	Eversource	Non-34.5 kV distribution circuits	18H1_21	Millyard	Southern	4.16	Low	2020	Normal
59	Eversource	Non-34.5 kV distribution circuits	41H2_61	North Dover	Eastern	4.16	Low	2020	Normal
60	Eversource	Non-34.5 kV distribution circuits	76W1_31	North Keene	Western	12.47	Low	2020	Normal
61	Eversource	Non-34.5 kV distribution circuits	3H1_21	Nowell Street	Southern	4.16	High	2022	Normal
62	Eversource	Non-34.5 kV distribution circuits	90H2_64	Pittsfield	Northern	4.16	High	2023	Normal
63	Eversource	Non-34.5 kV distribution circuits	48H1_63	Rye	Eastern	4.16	High	2025	Normal

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
64	Eversource	Non-34.5 kV distribution circuits	51H1_61	Salmon Falls	Eastern	4.16	High	2020	Normal
65	Eversource	Non-34.5 kV distribution circuits	4W2_31	Swanzey	Western	12.47	High	2023	Normal
66	Eversource	Non-34.5 kV distribution circuits	37H1_42	Tilton	Northern	4.16	Base	2020	Normal
67	Eversource	Non-34.5 kV distribution circuits	37H2_42	Tilton	Northern	4.16	Base	2020	Normal
68	Liberty	Transformer	L1	Olde Trolley 18	Salem NH	13.2	High	2026	>100% of Emergency Rating
69	Liberty	Transformer	L2	Olde Trolley 18	Salem NH	13.2	High	2026	>100% of Emergency Rating
70	Liberty	Transformer	L3	Olde Trolley 18	Salem NH	13.2	High	2027	>100% of Emergency Rating
71	Liberty	Transformer	L4	Olde Trolley 18	Salem NH	13.2	Low	2022	>100% Normal
72	Liberty	Transformer	L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal
73	Liberty	Transformer	L2	Salem Depot 9	Salem NH	13.2	Low	2020	>100% of Emergency Rating
74	Liberty	Transformer	L3	Salem Depot 9	Salem NH	13.2	High	2020	>100% of Emergency Rating
75	Liberty	Transformer	L1	Spicket River 13	Salem NH	13.2	High	2027	>100% of Emergency Rating
76	Liberty	Transformer	L2	Spicket River 13	Salem NH	13.2	High	2027	>100% of Emergency Rating
77	Liberty	Transformer	L3	Spicket River 13	Salem NH	13.2	High	2027	>100% of Emergency Rating
78	Liberty	Transformer	T2	Mount Support 16	Lebanon	13.2	High	2021	>100% of Emergency Rating
79	Liberty	Transformer	T1	Vilas Bridge 34	Bellows Falls	13.2	Base	2020	>100% of Emergency Rating
80	Liberty	Feeders	18L4	Olde Trolley 18	Salem NH	13.2	Low	2022	>100% Normal
81	Liberty	Feeders	14L4	Pelham 14	Salem NH	13.2	High	2021	>100% Normal
82	Liberty	Feeders	9L1	Salem Depot 9	Salem NH	13.2	Base	2020	>100% Normal

No.	EDC	Asset Type	Asset Name	Substation	Region	Voltage	Forecast that Triggers Violation	First Violation Year	Violation Type
83	Liberty	Feeders	9L2	Salem Depot 9	Salem NH	13.2	High	2029	>100% Normal
84	Liberty	Feeders	13L3	Spicket River 13	Salem NH	13.2	High	2026	>100% Normal
85	Liberty	Feeders	15H1	Monroe 15	Monroe	2.4	Low	2020	>100% Normal
86	Liberty	Feeders	11L1	Craft Hill 11	Lebanon	13.2	Low	2022	>100% Normal
87	Liberty	Feeders	16L1	Mount Support 16	Lebanon	13.2	Low	2022	>100% Normal
88	Liberty	Feeders	16L4	Mount Support 16	Lebanon	13.2	Base	2021	>100% Normal
89	Liberty	Feeders	16L5	Mount Support 16	Lebanon	13.2	High	2026	>100% Normal
90	Unitil	Transformer	Penacook 4T3 Xfmr	Penacook	Capital	13.8	High	2022	>90% Normal
91	Unitil	Transformer	Bow Junction 7T2 Xfmr	Bow Junction	Capital	13.8	Base	2022	>90% Normal
92	Unitil	Transformer	Boscawen 13T1 Xfmr	Boscawen	Capital	13.8	High	2028	>90% Normal
93	Unitil	Transformer	Bow Bog 18T2 Xfmr	Bow Bog	Capital	13.8	Base	2024	>90% Normal
94	Unitil	Transformer	Iron Works Road 22T1 Xfmr	Iron Works Road	Capital	13.8	High	2022	>90% Normal
95	Unitil	Transformer	Dow's Hill 20T1	Dow's Hill	Seacoast	4.16	Base	2021	>90% Normal
96	Unitil	Transformer	Hampton Beach 3T3	Hampton Beach	Seacoast	13.8	High	2028	>90% Normal
97	Unitil	Transformer	Seabrook 7T1	Seabrook	Seacoast	13.8	High	2028	>90% Normal
98	Unitil	Transformer	Timberlane 13T1	Timberlane	Seacoast	13.8	High	2025	>90% Normal
99	Unitil	Circuit	1H1	Bridge Street	Capital	4.16	High	2023	>90% Normal
100	Unitil	Circuit	3H2	Gulf Street	Capital	4.16	High	2028	>90% Normal
101	Unitil	Circuit	4W4	Penacook	Capital	13.8	High	2028	>90% Normal
102	Unitil	Circuit	18W2	Bow Bog	Capital	13.8	Base	2025	>90% Normal
103	Unitil	Circuit	22W1	Iron Works Road	Capital	13.8	High	2028	>90% Normal
104	Unitil	Circuit	24H1	Hazen Drive	Capital	4.16	High	2025	>90% Normal
105	Unitil	Circuit	Gilman Lane 19X3	Gilman Lane	Seacoast	34.5	High	2029	>90% Normal
106	Unitil	Circuit	3W4	Hampton Beach	Seacoast	13.8	High	2024	>90% Normal
107	Unitil	Circuit	7W1	Seabrook	Seacoast	13.8	High	2028	>90% Normal
108	Unitil	Circuit	21W2	Westville	Seacoast	13.8	High	2027	>90% Normal
109	Unitil	Circuit	58X1W	Westville Tap	Seacoast	34.5	High	2028	>90% Normal

Source: Guidehouse, EDC data

Appendix C. Selection of Real Economic Carrying Charge

The study considers two options when determining which methodological approach would be the most appropriate given the objectives of the study. The first option, referred to as Option A, includes assuming a specific avoidance duration (e.g., 10 years) to determine the annual dollar value of avoidance. The second option, Option B, considers approaches where no specific avoidance timeframe needs to be assumed. Instead the approach leverages the assumption that the investment is avoided for all years of the investment life (e.g., 30 years) after the initial year of need. Because the scope includes a timeframe of 10 forward-looking years, in this study the avoidance value is quantified from the year of initial investment through the end of the study period.

The study considers two methodological approaches that can be used for Option A, when an avoidance timeframe is assumed. These are referred to as Method A and Method B. The methods, and the pros and cons of each, are summarized below:

- **Method A: Annualization of difference in NPV of revenue requirement.** This approach entails determining the NPV of the revenue requirement with the investment made in year 1 versus the investment made after some fixed avoidance period (i.e., 5 to 10 years). This provides a single total dollar value which then needs to be annualized over the avoidance years.
  - **Pros:** If the investment at the end of the avoidance period and the duration of the avoidance period is known, then this method provides the most accurate representation of the avoided costs for a specific asset.
  - **Cons:** This method is not as appropriate for a generalized study such as the one being undertaken here to develop an indicative set of locational values of distributed generation because a set timeframe for deferral or avoidance is uncertain and may vary across locations.
- **Method B: RECC with avoidance period.** This method captures the difference in NPV of two payment streams: the revenue requirement of an investment made in year 0 compared to the same project avoided to year 1.
  - **Pros:** The RECC method is a flexible method in that it can be used to determine the total value of avoiding an investment for a set period of time. This total value can then be annualized in a similar way as Method A.
  - **Cons:** The RECC method may produce higher or lower results than the results of Method A for the same avoidance timeframe, cost, and asset lifetime. If a specific avoidance timeframe can be determined Method A may be more appropriate.

Given the limitations and the number of assumptions required for either Method A or Method B within Option A, the study turned to Option B which involves formulas that do not require a set assumed deferral or avoidance period. Similar to Option A the study looked at two methodological approaches to support this option. These are referred to as Method C and Method D, and the pros and cons of each method are summarized below:

- **Method C: RECC without an assumed avoidance period.** The RECC method creates a stream of annual values over the lifetime of the investment or asset which can be leveraged directly as the annualized value in that year. (Note, for the purposes of this LVDG study, annual avoidance values would be quantified through the end of the study time period.)
    - **Pros:** This is a flexible approach since it does not require a set avoidance timeframes to calculate annual avoided costs.
    - **Cons:** This method assumes the investment is avoided for the study timeframe; it does not consider that an investment may not be fully avoided within the study timeframe period. It also does not quantify the value of avoided investment beyond the study timeframe.
- **Method D: Flat annualized cost.** This method calculates a flat annualized cost or payment from the revenue requirement such that the present value of all the annual costs is equal to the revenue requirement.
    - **Pros:** This method is the simplest method of the methods considered and provides a constant nominal value over the life of the asset.
    - **Cons:** Since the capacity deficiency increases over time for the majority of the locations and scenarios considered, a flat annualized value would lead to a decreasing value per kW for the majority of cases.

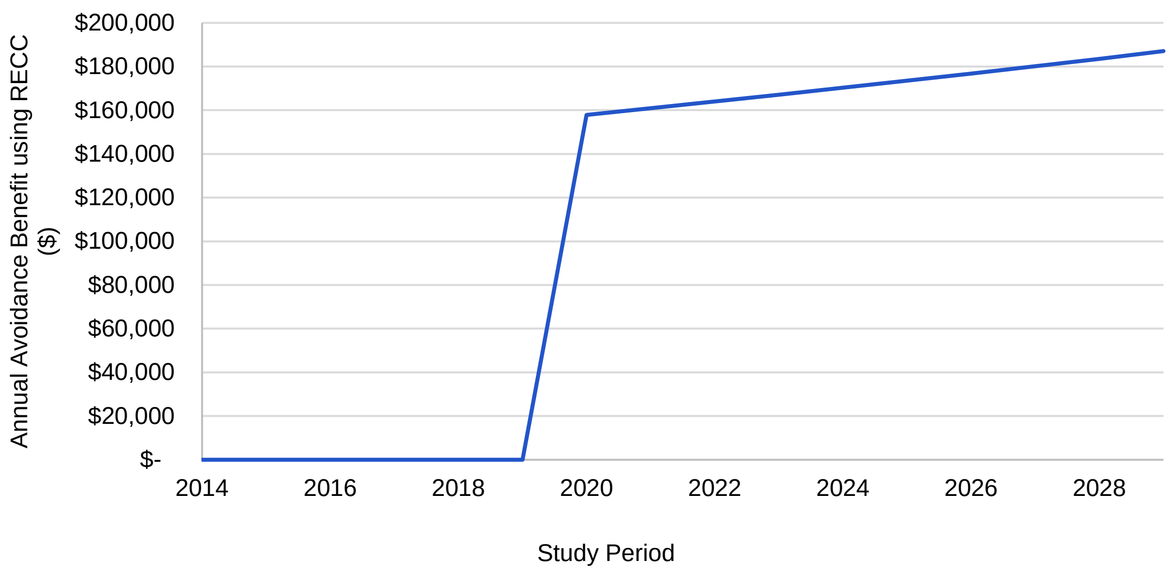
Appendix D. Economic Analysis

D.1 Three Additional Examples of Annual Value for Avoidance of Investment

Additional Example #1 - Madbury ROW Circuit (34.5 kV) Yearly and Hourly Economic Analysis (EDC: Eversource):

Annual avoidance value begins in 2020, the first year of the capacity deficit.[56]

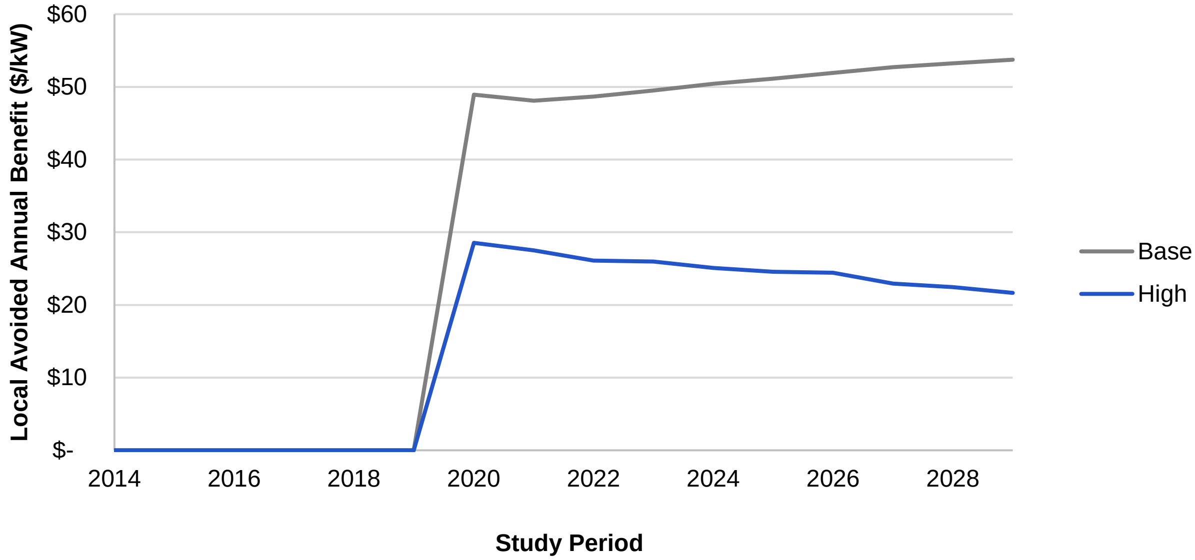
Figure D-1. Annual Avoidance Value – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

[56] Note: this deficit is driven by a change in planning criteria.

Figure D-2. Local Avoided Annual Value – Madbury ROW Circuit (34.5 kV)

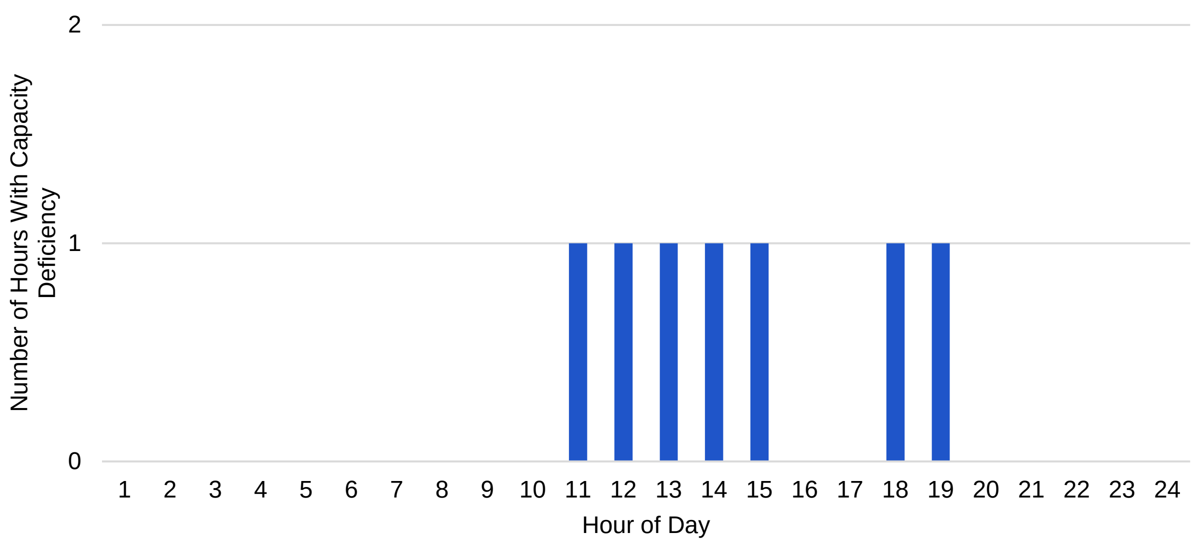


Source: Guidehouse, EDC data

Example Hourly Local Value Calculation for Madbury ROW Circuit (34.5 kV):

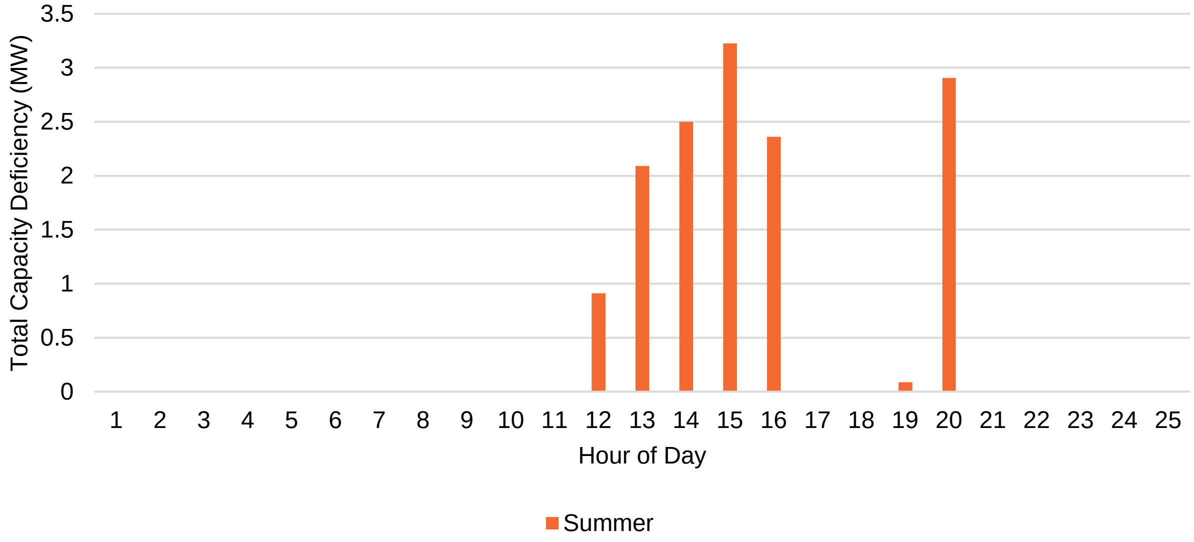
- Since Madbury ROW only has 1 day of capacity deficiency, the hourly and yearly analysis provide the same results.

Figure D-3. Number of Hours with Capacity Deficiency – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

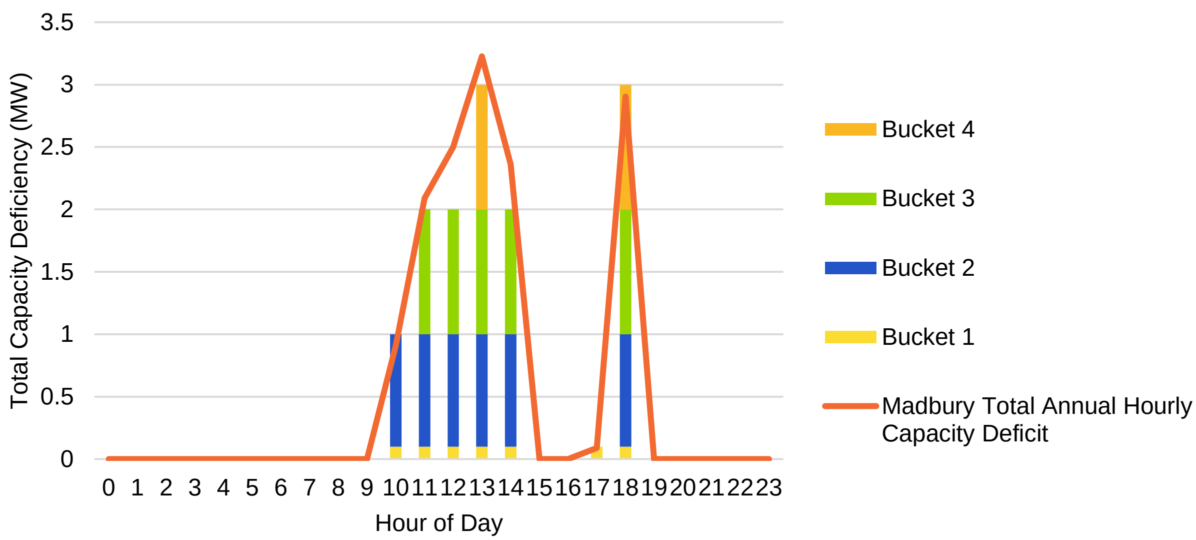
Figure D-4. Seasonal Capacity Deficiency Analysis – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

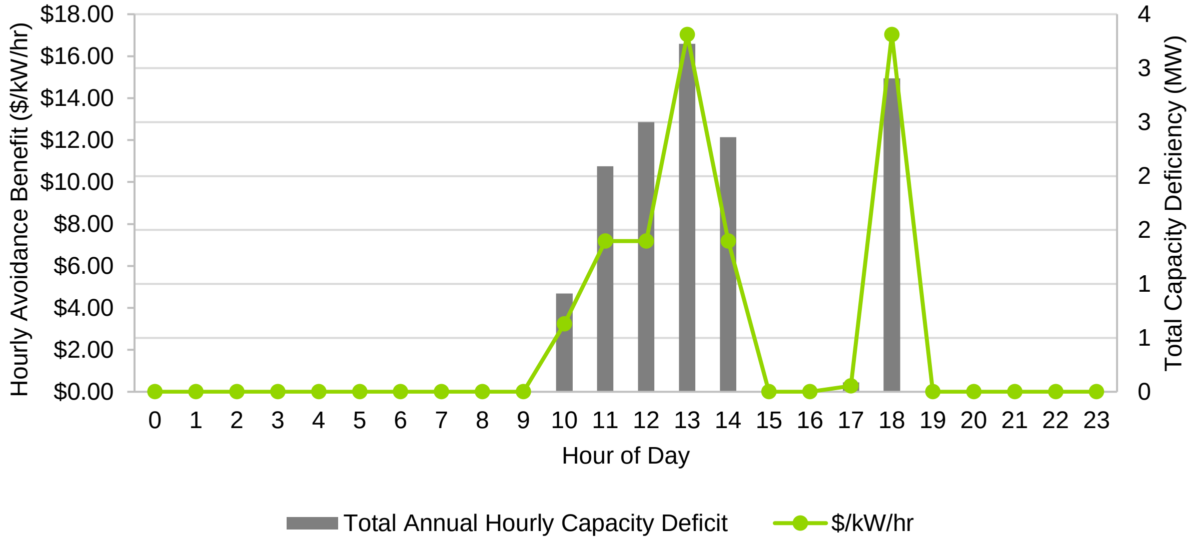
Madbury has two spikes on the peak day, but only four capacity deficiency buckets.

Figure D-5. Marginal Load Buckets (MW) – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

Figure D-6. Hourly Analysis for All Hours of Year – Madbury ROW Circuit (34.5 kV)

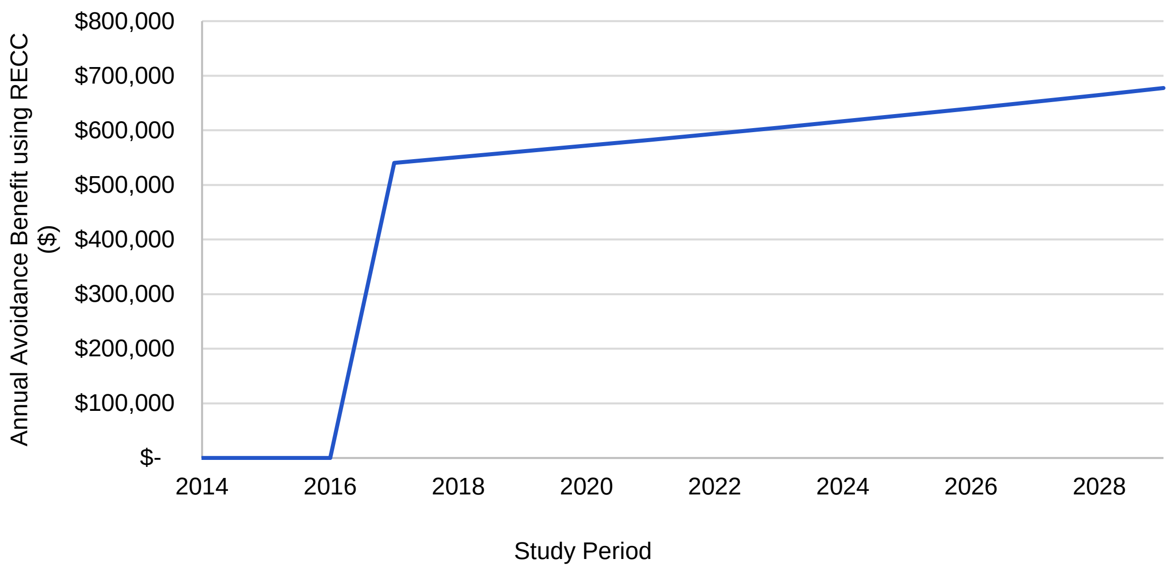


Source: Guidehouse, EDC data

Additional Example #2 - Mount Support Substation Yearly and Hourly Economic Analysis (EDC: Liberty):

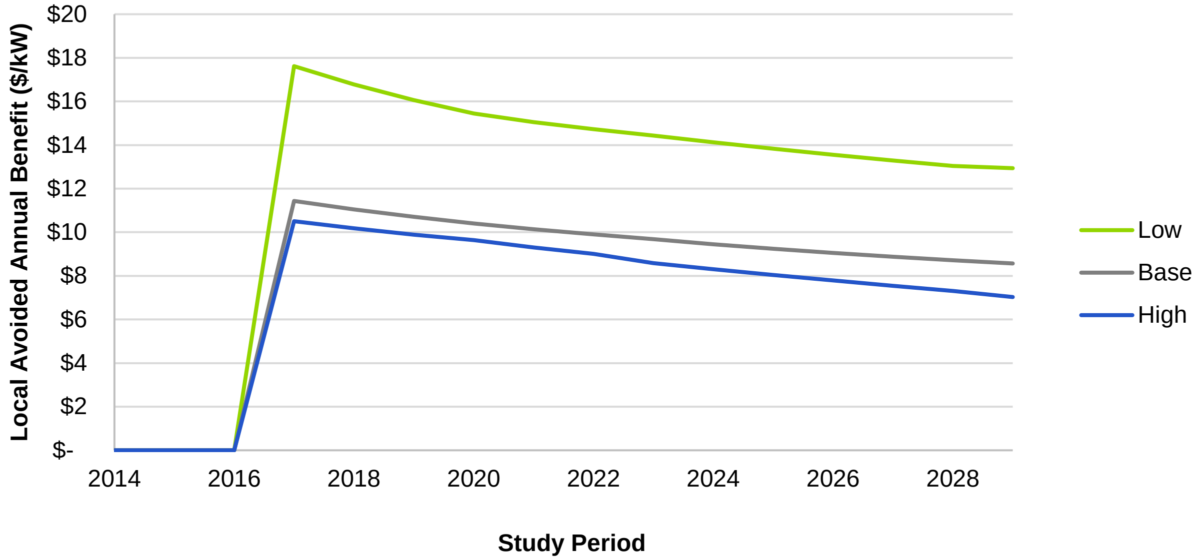
The annual avoidance value begins in 2017 and continues throughout the study period.

Figure D-7. Annual Avoidance Value – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

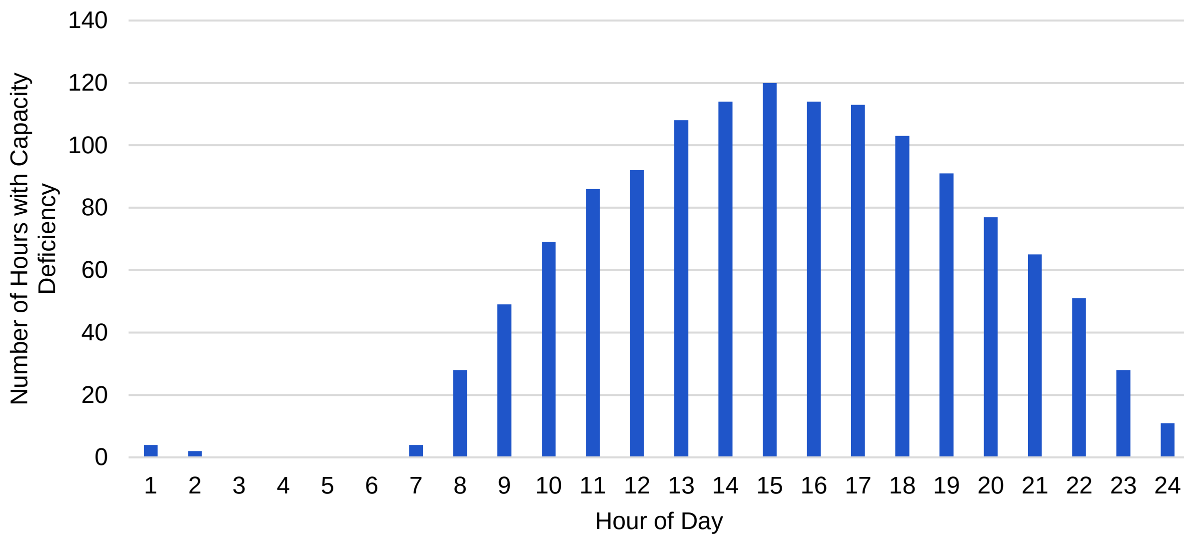
Figure D-8. Local Avoided Annual Value – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

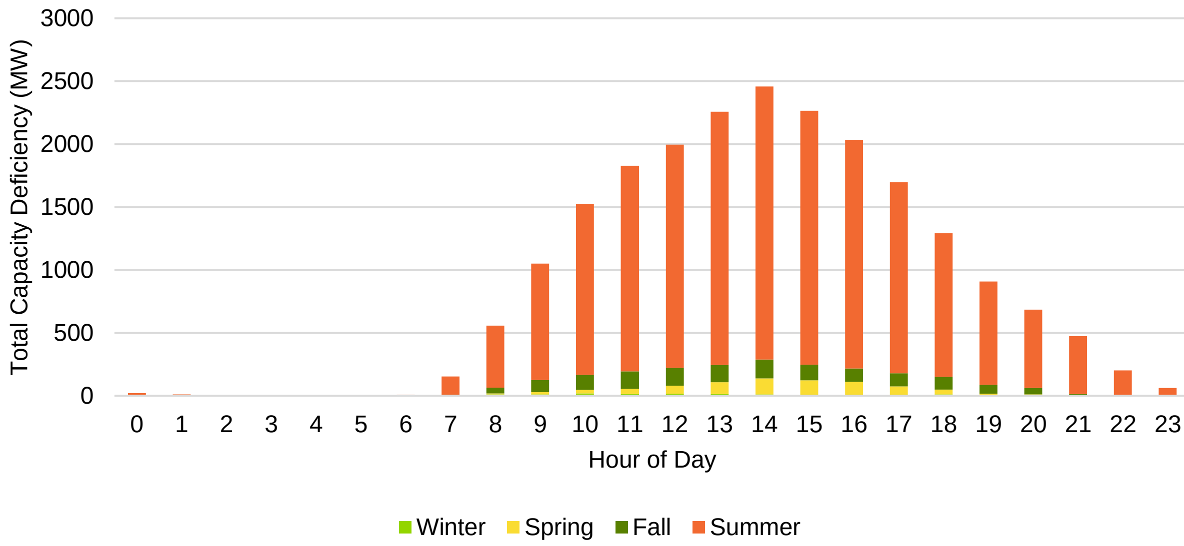
Mount Support is a historical project that had significant capacity deficiency in the region before the upgrade was performed.

Figure D-9. Number of Hours with Capacity Deficiency – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

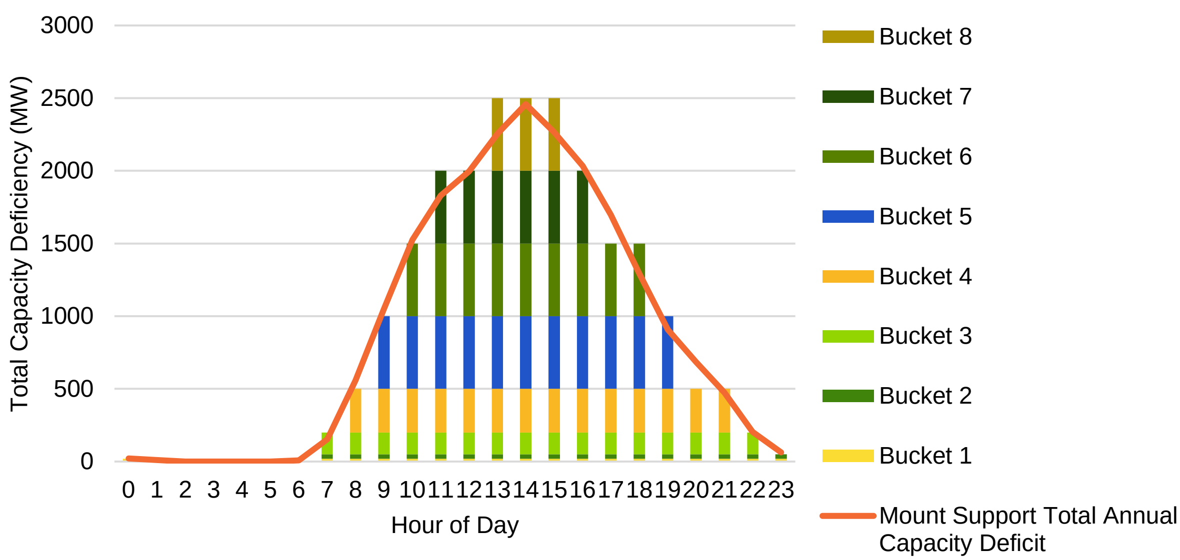
Figure D-10. Seasonal Capacity Analysis – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

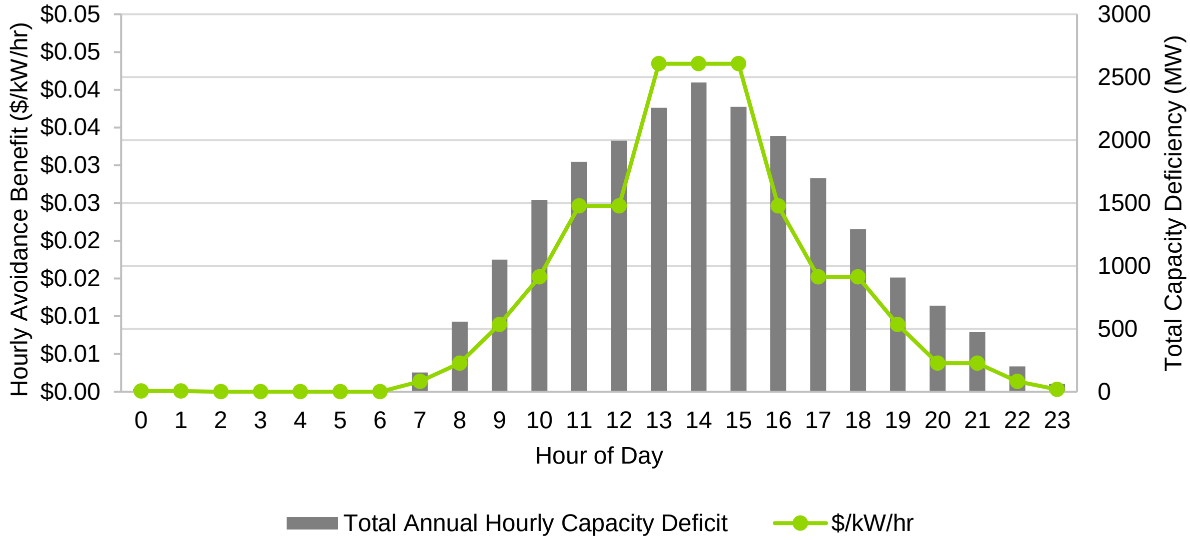
Given the number of hours of need and the large capacity deficiency for some hours, the hourly value of avoidance is small.

Figure D-11. Marginal Load Buckets (MW) – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

Figure D-12. Hourly Analysis for All Hours of Year – Mount Support Substation (Bulk)

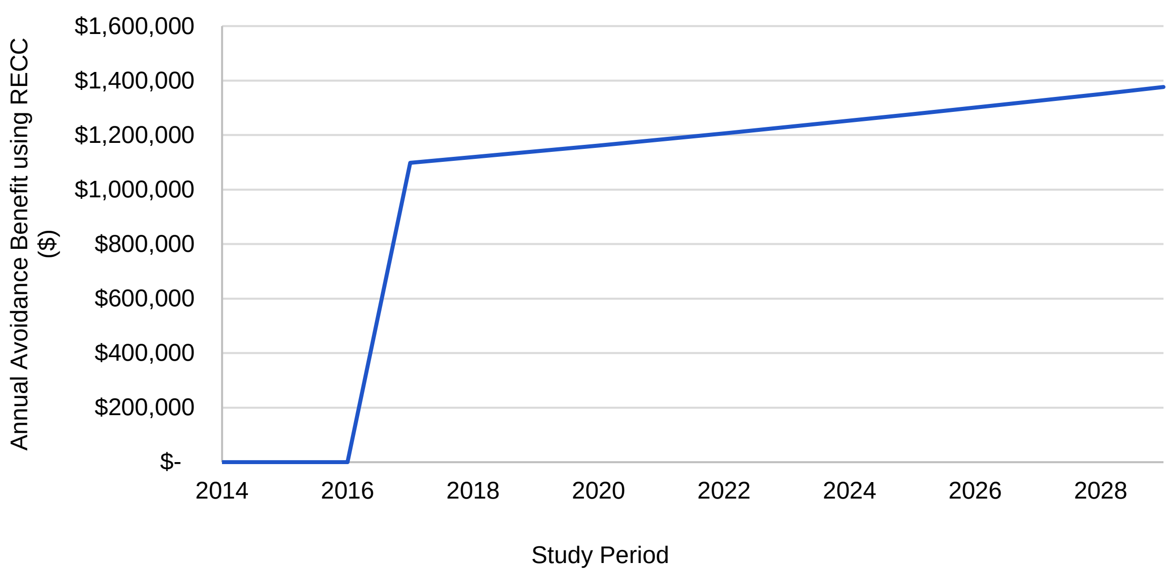


Source: Guidehouse, EDC data

Additional Example #3 - Kingston Substation Yearly and Hourly Economic Analysis (EDC: Unitil):

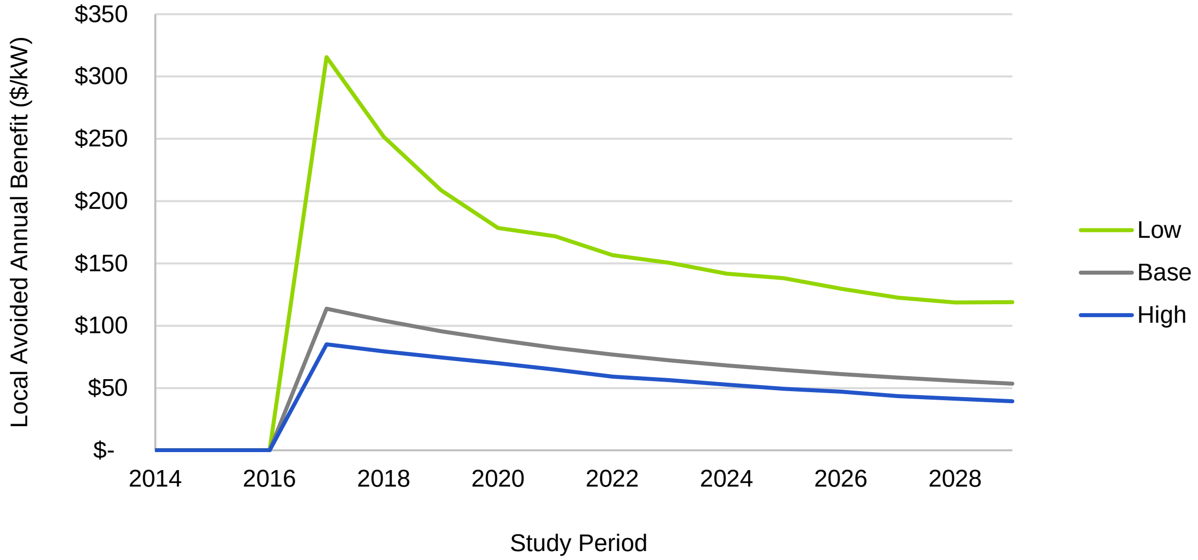
The annual avoidance value begins in 2017 and continues throughout the study period.

Figure D-13. Annual Avoidance Value – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

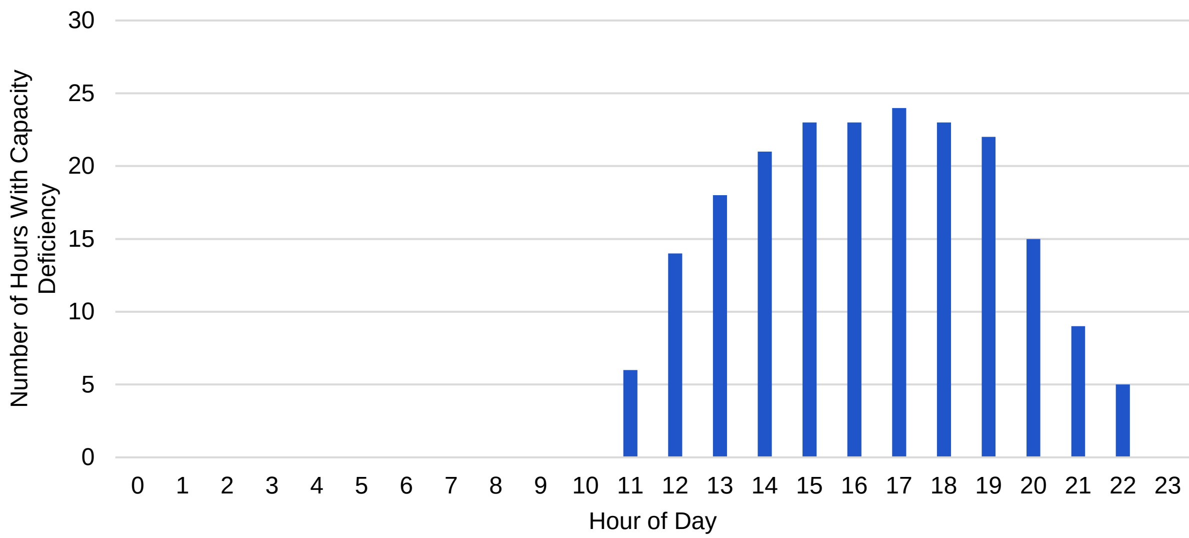
Figure D-14. Local Avoided Annual Value – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

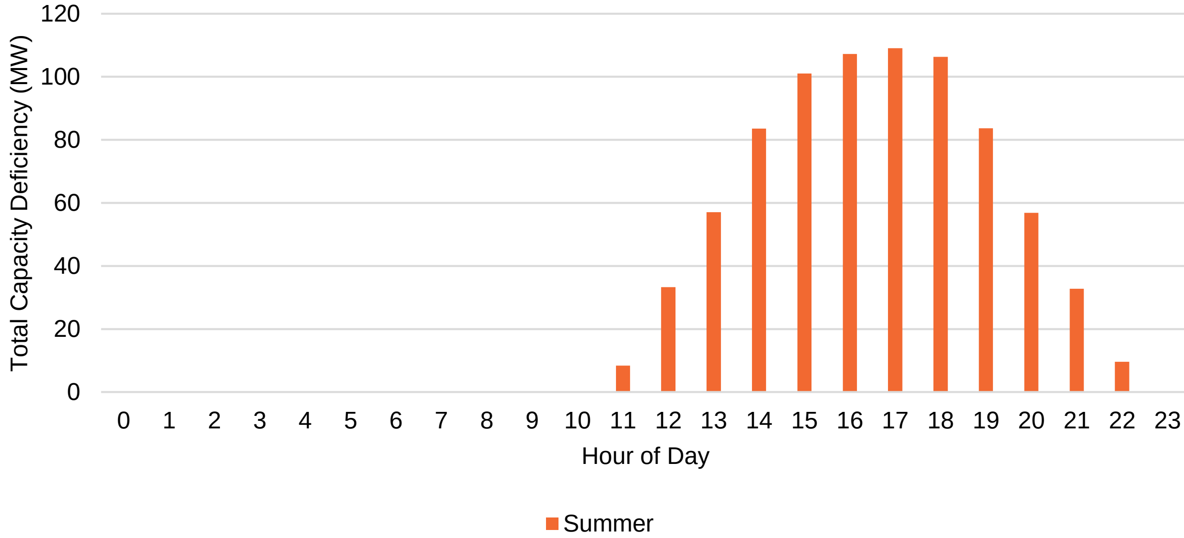
Kingston is a historical project. Based on the seacoast regional hourly load profile, this location only has periods of need during the summer season.

Figure D-15. Number of Hours with Capacity Deficiency – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

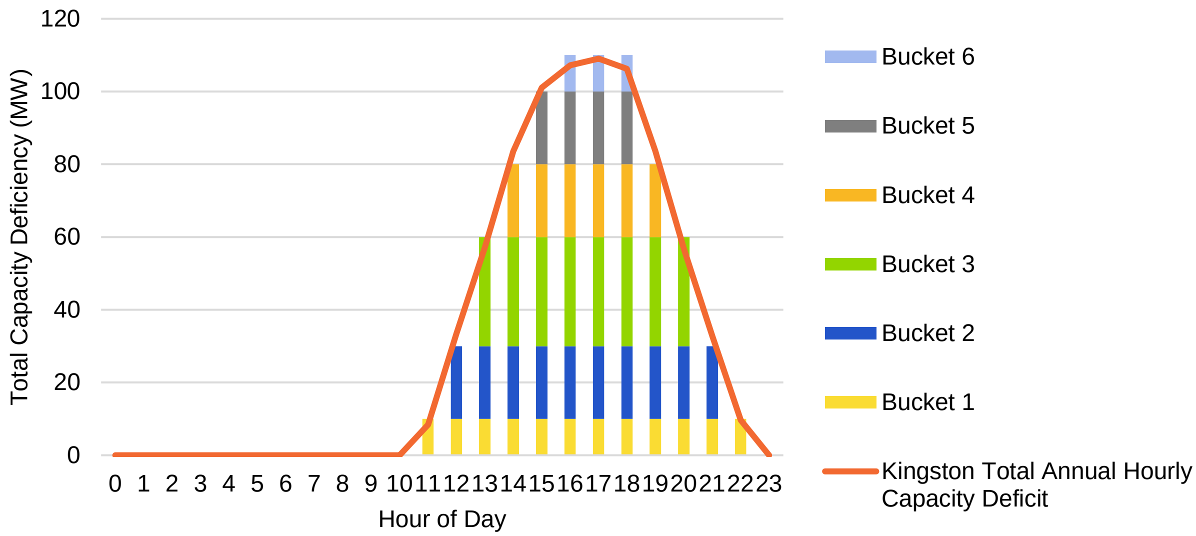
Figure D-16. Seasonal Capacity Deficiency Analysis – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

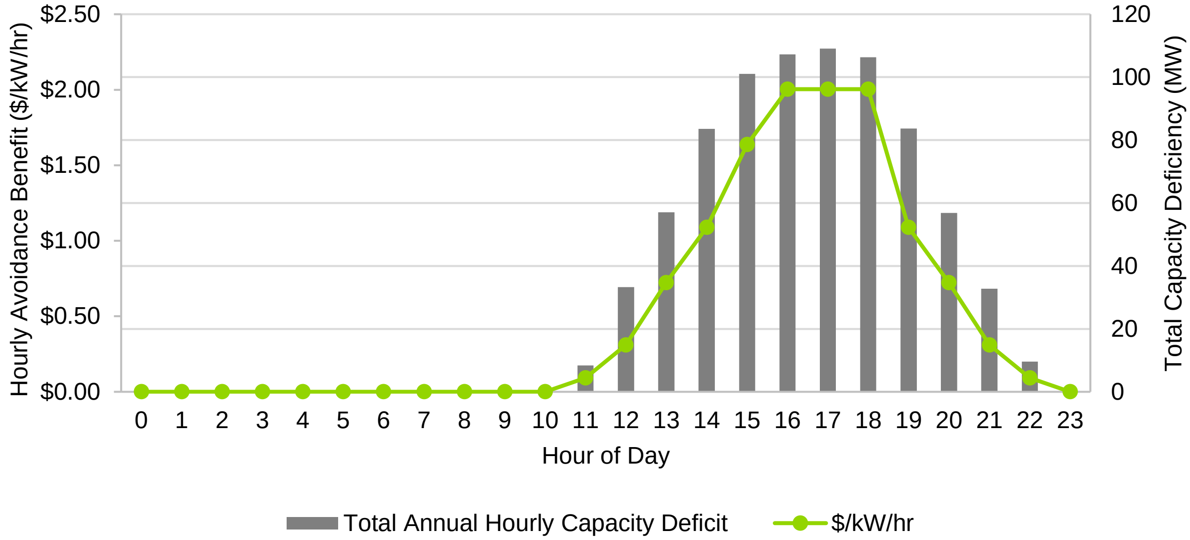
While the revenue requirement for Kingston was the highest of all the examples, the hourly value is lower than Pemi and Madbury because the capacity deficiency in terms of total MWh is higher than for Pemi and Madbury.

Figure D-17. Marginal Load Buckets (MW) – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

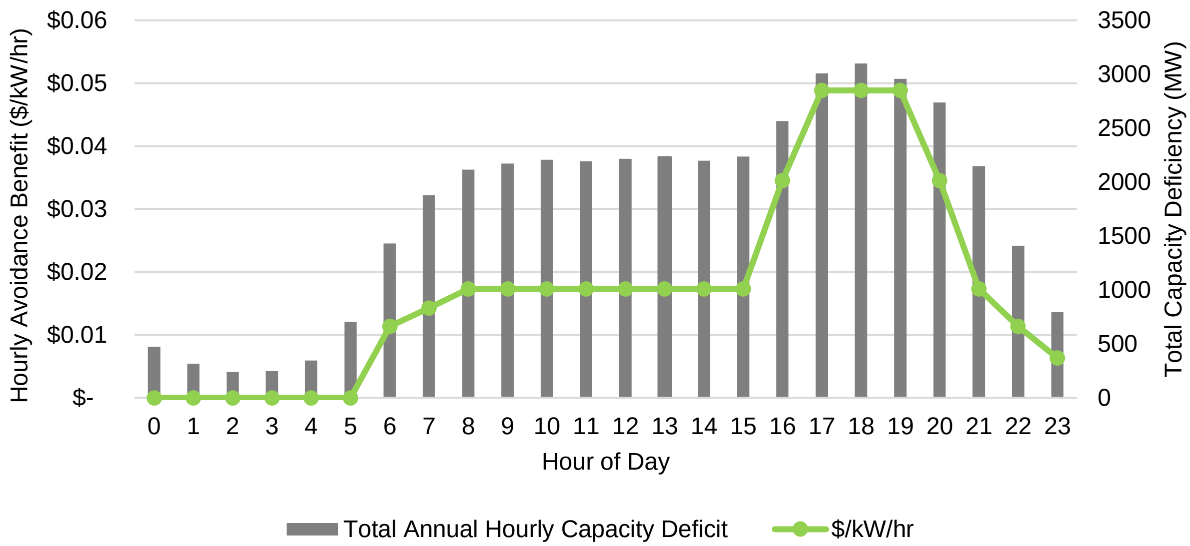
Figure D-18. Hourly Analysis for All Hours of Year – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

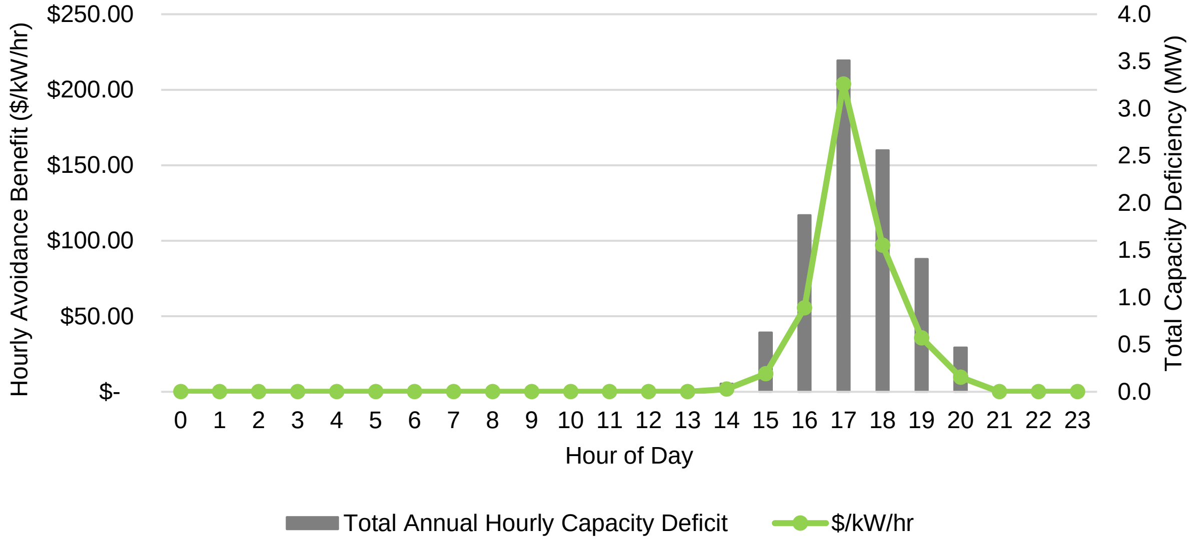
D.2 Hourly Analysis Results for Remaining 11 Sites

Figure C-19. Hourly Analysis for All Hours of Year – South Milford Substation (Bulk)



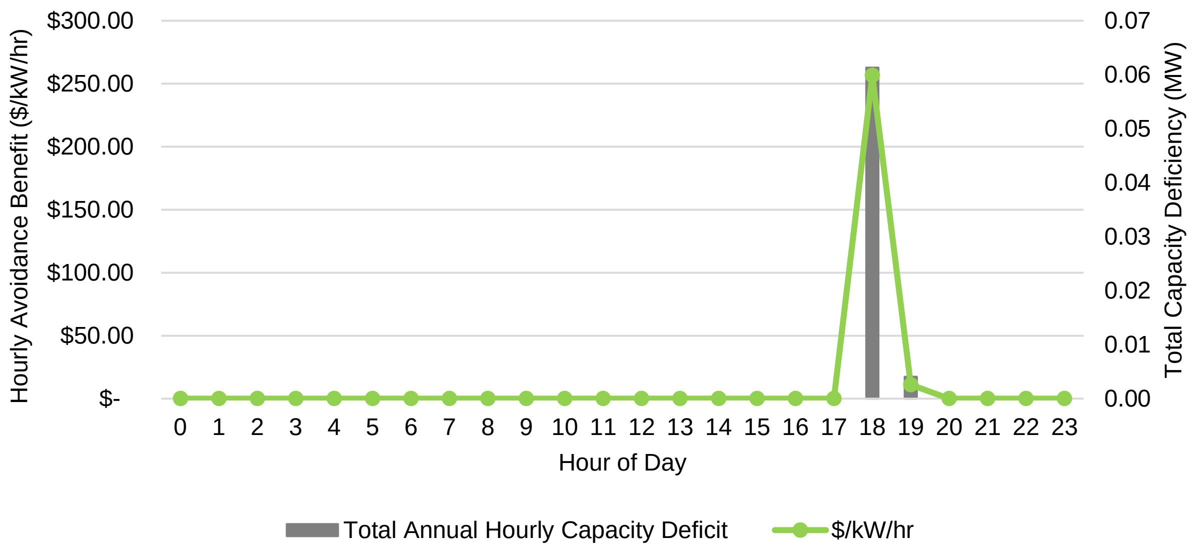
Source: Guidehouse, EDC Data

Figure C-20. Hourly Analysis for All Hours of Year – Monadnock Substation (Bulk)



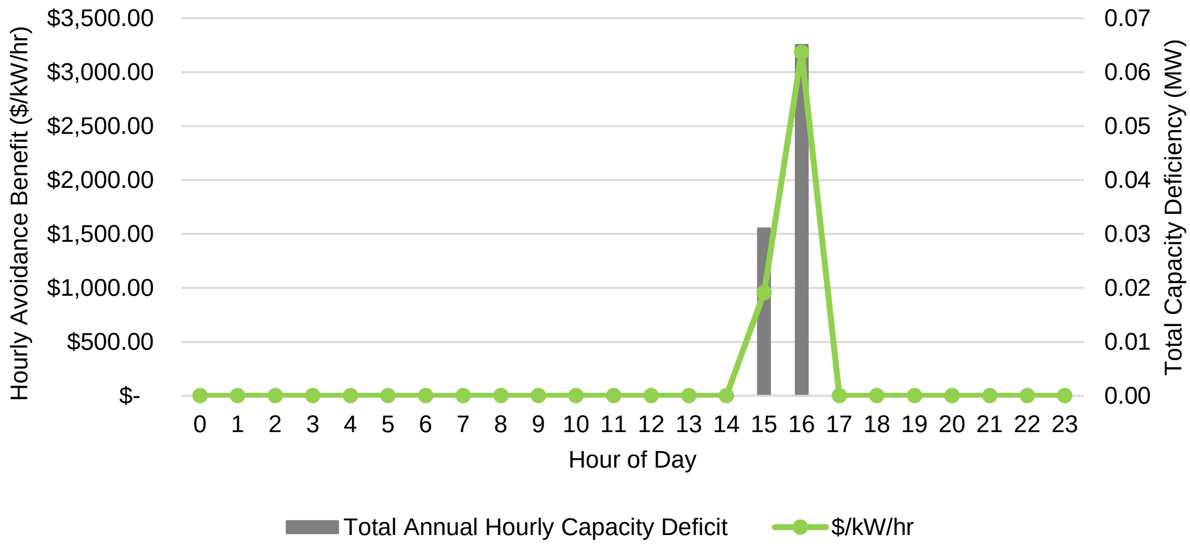
Source: Guidehouse, EDC Data

Figure C-21. Hourly Analysis for All Hours of Year – East Northwood Substation (Bulk)



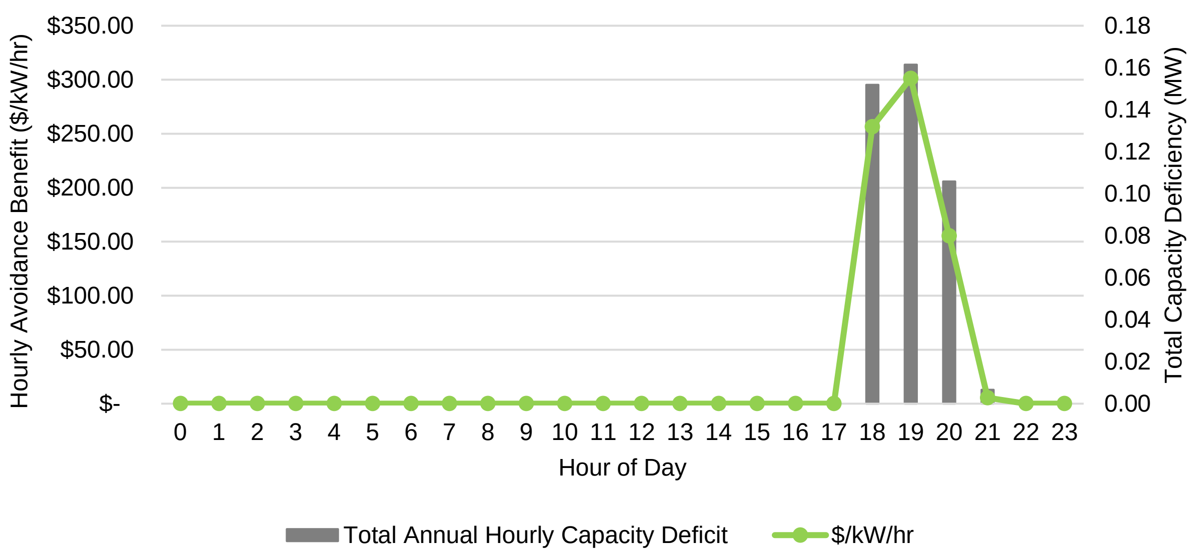
Source: Guidehouse, EDC Data

Figure C-22. Hourly Analysis for All Hours of Year – Rye Substation (Non-Bulk)



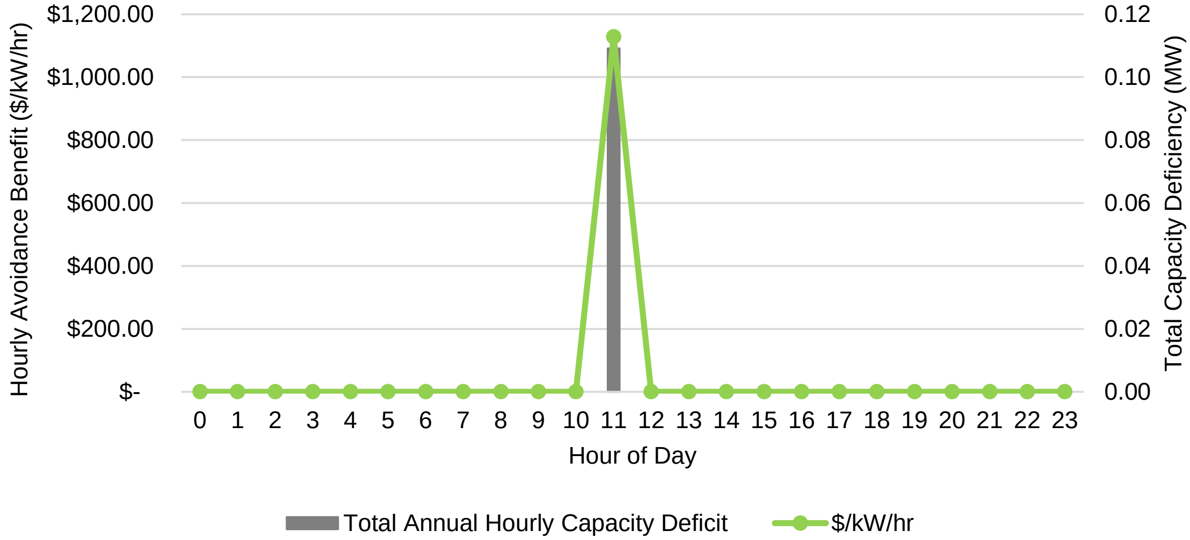
Source: Guidehouse, EDC Data

Figure C-23. Hourly Analysis for All Hours of Year – Bristol Substation (Non-Bulk)



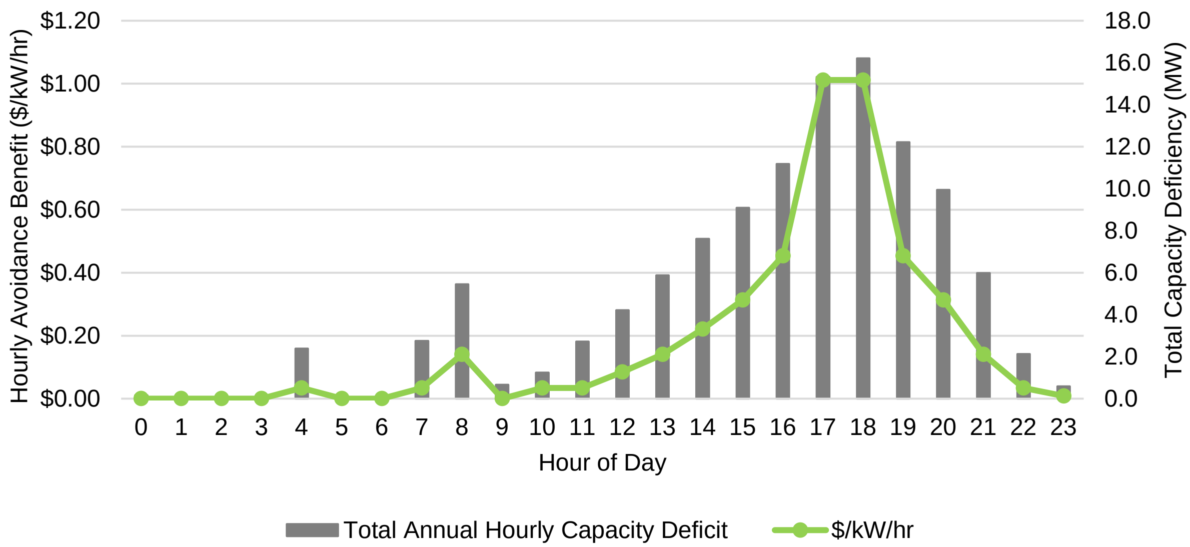
Source: Guidehouse, EDC Data

Figure C-24. Hourly Analysis for All Hours of Year – North Keene Circuit (12.47 kV)



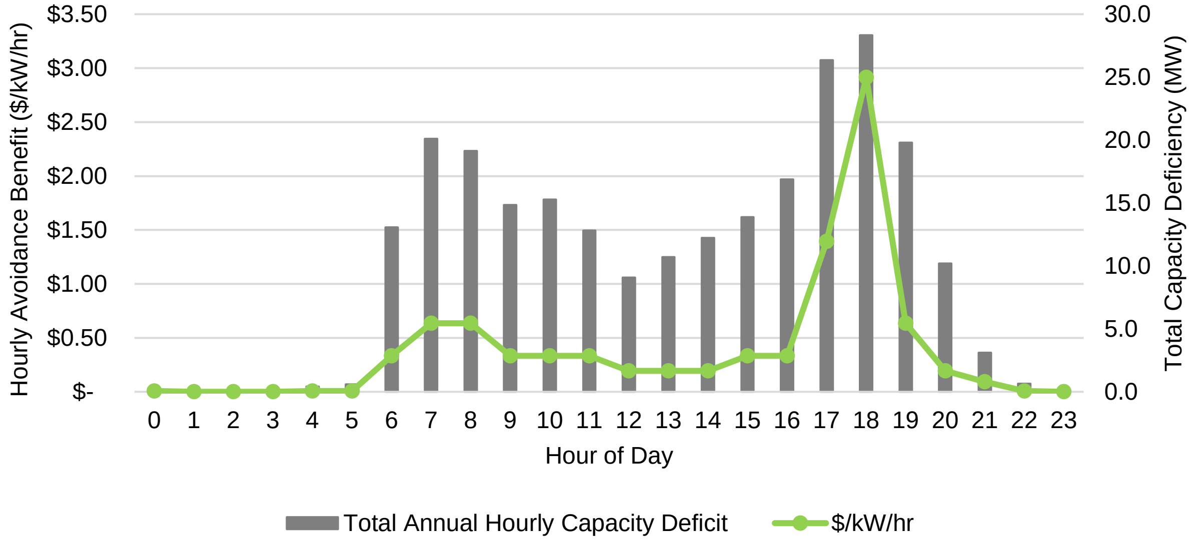
Source: Guidehouse, EDC data

Figure C-25. Hourly Analysis for All Hours of Year – Londonderry Circuit (34.5 kV)



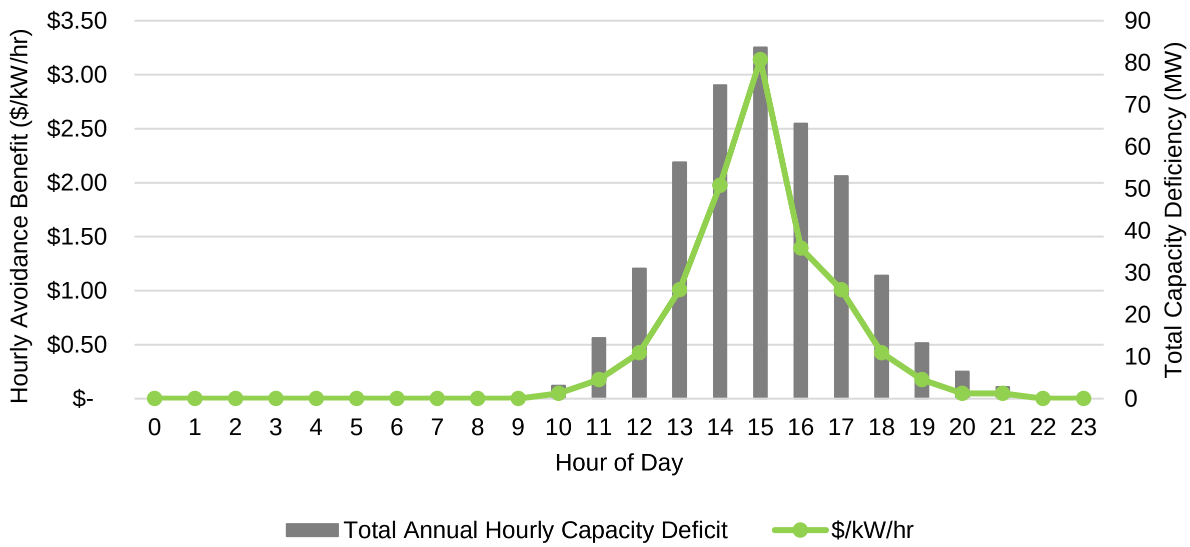
Source: Guidehouse, EDC Data

Figure C-26. Hourly Analysis for All Hours of Year – Vilas Bridge Substation (Non-Bulk)



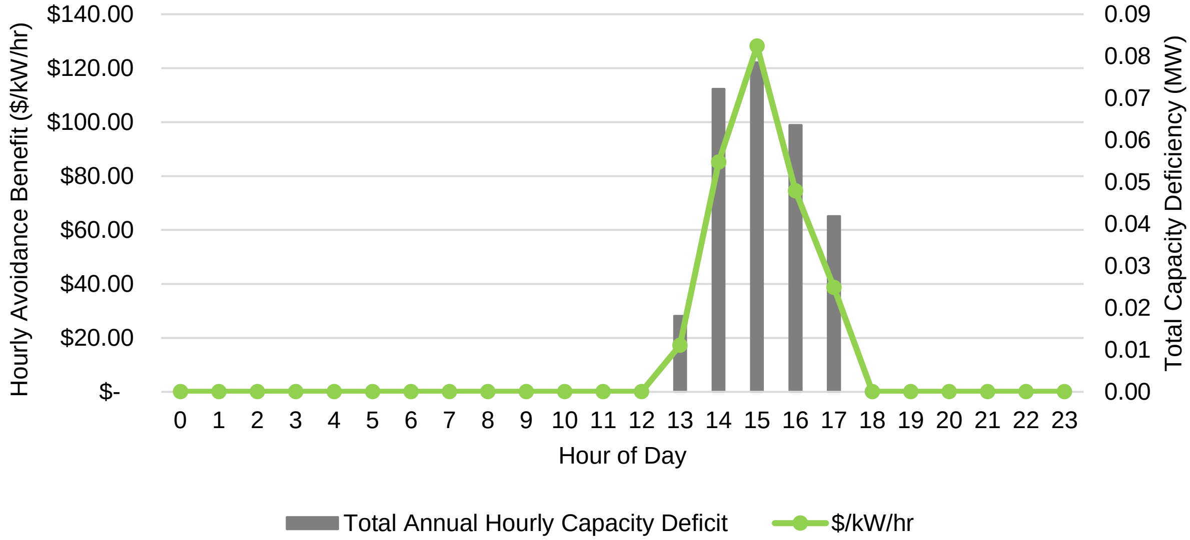
Source: Guidehouse, EDC Data

Figure C-27. Hourly Analysis for All Hours of Year – Golden Rock Substation (Bulk)



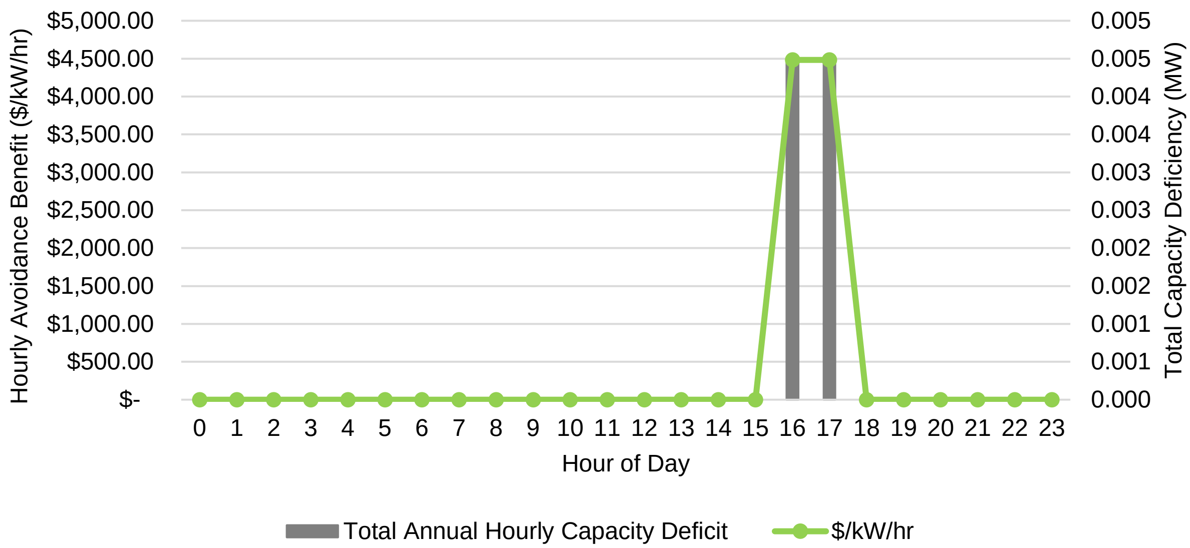
Source: Guidehouse, EDC Data

Figure C-28. Hourly Analysis for All Hours of Year – Bow Bog Substation (Bulk)



Source: Guidehouse, EDC Data

Figure C-29. Hourly Analysis for All Hours of Year – Dow's Hill Substation (Bulk)



Source: Guidehouse, EDC Data

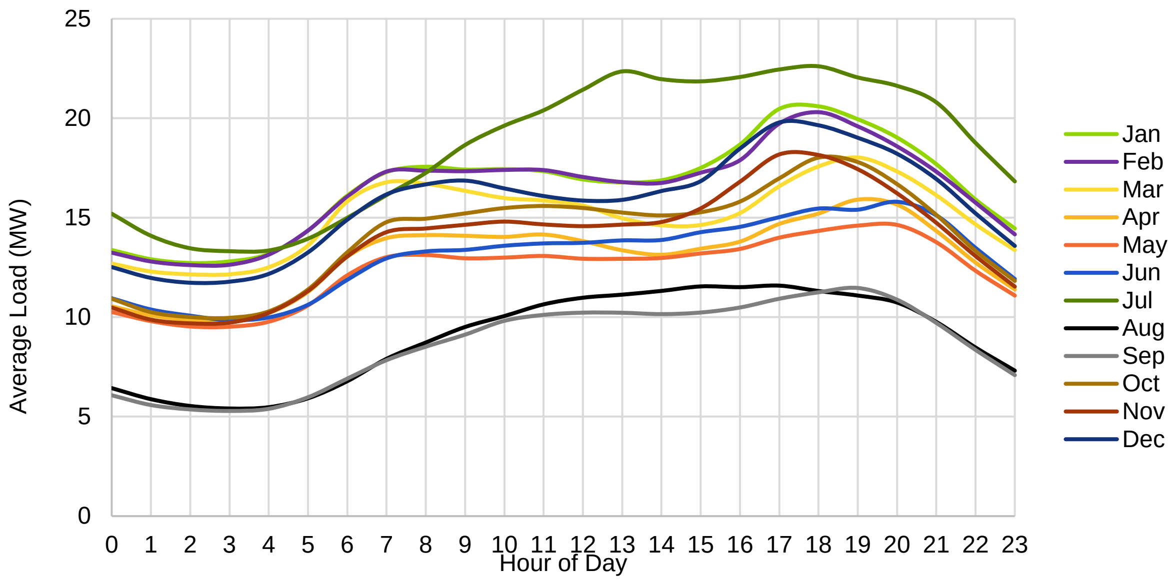
Appendix E. Additional Examples of Load and DG Output Profiles

E.1 Three Additional Examples of Locational Load Profiles

Details of the Eversource location including the following:

- Madbury ROW Circuit (34.5 kV) has reasonably consistent mid-afternoon to evening summer peaks
- Summer midday normal overload on distribution supply line
- Annual Peak Day: 7/20/2019 13:00, 32.58 MW

Figure E-1. Average Hourly Profile by Month – Madbury ROW Circuit (34.5 kV)

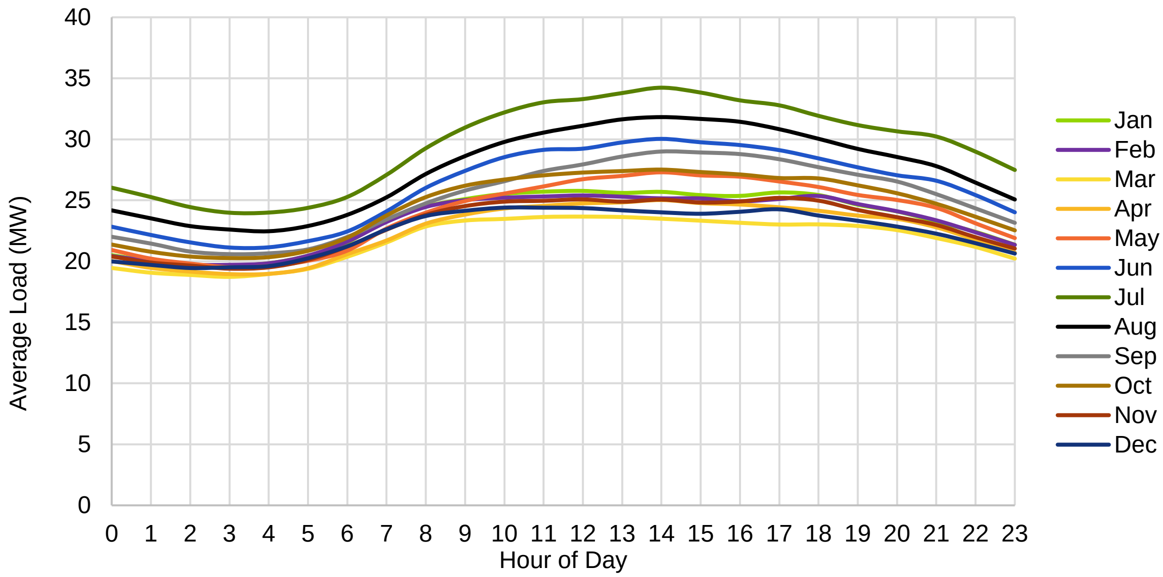


Source: Guidehouse, EDC data

Details of the Liberty location include the following:

- Mount Support Substation (Bulk) is a summer peaking substation with a midday peak
- Annual Peak Day: 7/30/2019 14:00, 40.9 MW

Figure E-2. Average Hourly Profile by Month – Mount Support Substation (Bulk)

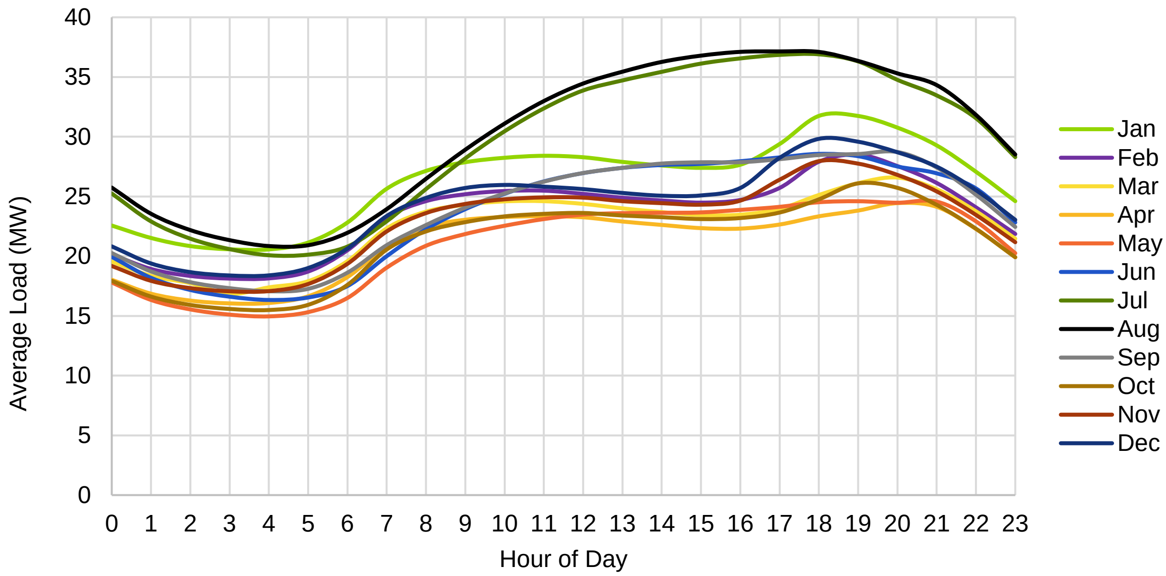


Source: Guidehouse, EDC data

Details on the Unitil location include the following:

- Kingston Substation (Bulk) used the seacoast region 8,760 load data since no hourly level data is available at the substation
- The seacoast region is summer peaking with higher average peaks in July and August
- July and August have the highest average load in the seacoast region
- Kingston Annual Peak Day: 8/29/2018 17:00, 51,000 kW

Figure E-3. Average Hourly Profile by Month – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

E.2 Three Additional Detailed Examples of DG Production Profile Mapping to Load

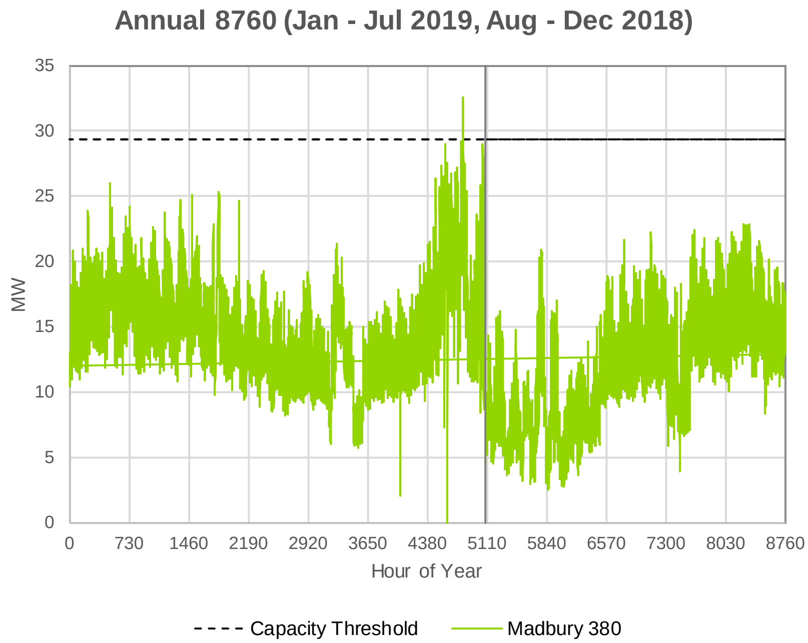
Madbury ROW Circuit (34.5 kV) DG Analysis Results

Madbury ROW Circuit (34.5 kV) – Annual Load Profile and Capacity Threshold:

Figure E-4 is an example of a location where the hours of capacity deficiencies occur during a relatively small number of hours on a major distribution line. All hours of capacity deficiency occur during a single summer day (but increase to several days during later years). This is a summer peaking location with midday normal (N-0) overload.

- Annual hours of capacity deficiency: 7
- Energy deficiency: 14 MWh
  - Approximately, 0.012% of total energy (121,360 MWh)

Figure E-4. Capacity Deficiencies – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

Table E-1. Annual Load Profile and Capacity Threshold – Madbury ROW Circuit (34.5 kV)

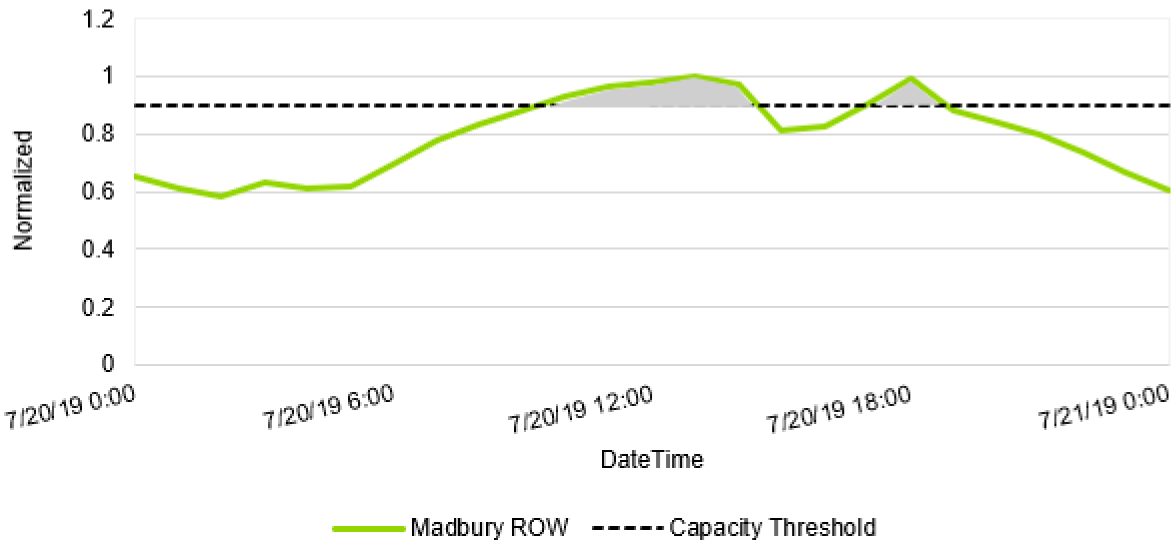
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Madbury ROW Circuit (34.5 kV)	**Eastern**	**32.58**	**7/20/19 13:00**	**3.23**

Source: Guidehouse, EDC data

Madbury ROW Circuit (34.5 kV) – Annual Peak Day and Capacity Threshold:

- Summer peaking with midday and early evening normal overload
- Hours of capacity deficiency only occur for a single summer peak day
- Total of 7 hours of capacity deficiency are split across midday and evening hours
- The number of hours of capacity deficiencies increases over time due to load growth

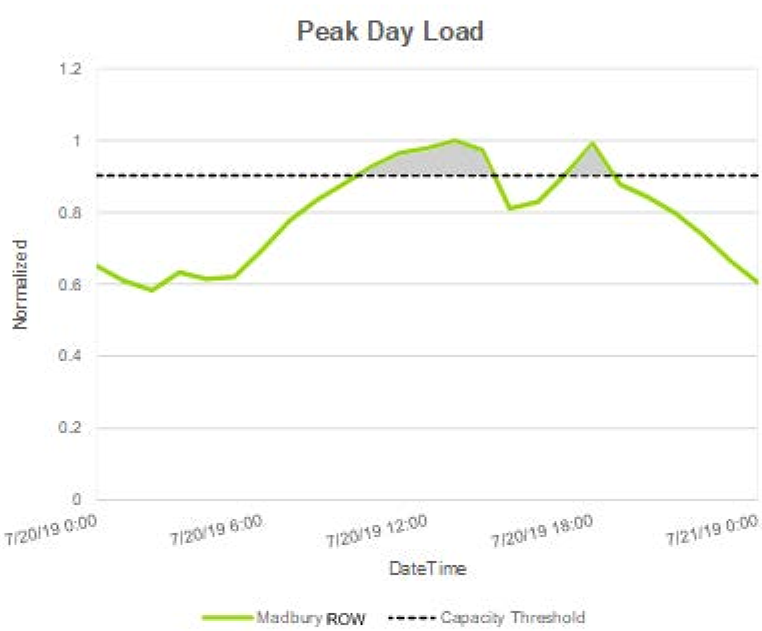
Figure E-5. Summer Peak Day Load – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

Figure E-6 presents the summer peak day for Madbury during which capacity deficiencies occur. Deficiencies occurred on 1 day and the number of hours of capacity deficiencies over the year are low; however, on the peak day the hours when deficiencies occur extend from midday to early evening.

Figure E-6. Capacity Deficiencies – Madbury ROW Circuit (34.5 kV)

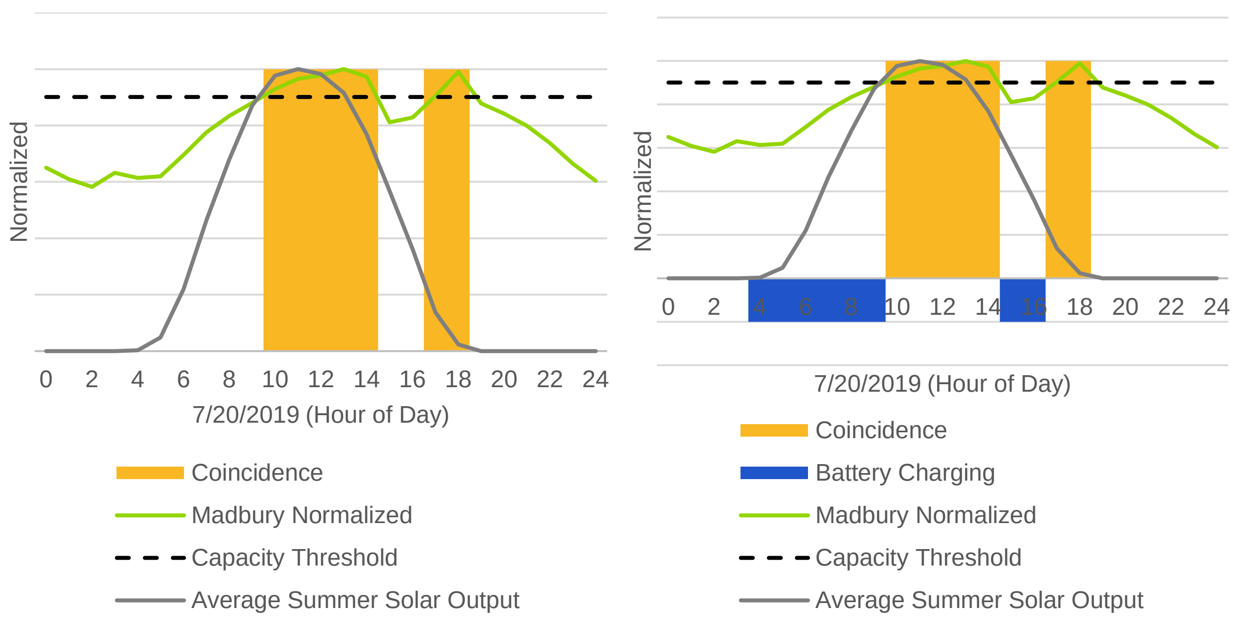


Source: Guidehouse, EDC data

Madbury ROW Circuit (34.5 kV) – Solar Coincidence and Solar plus Storage Charging Analysis:

- Summer coincidence of solar production: 7 out of 7 hours
- Summer: 8-hour charging interval, no hours needed for storage discharge (if enough solar is produced during peak hours)

Figure E-7. Solar Coincidence and Solar plus Storage Charging Analysis – Madbury ROW Circuit (34.5 kV)

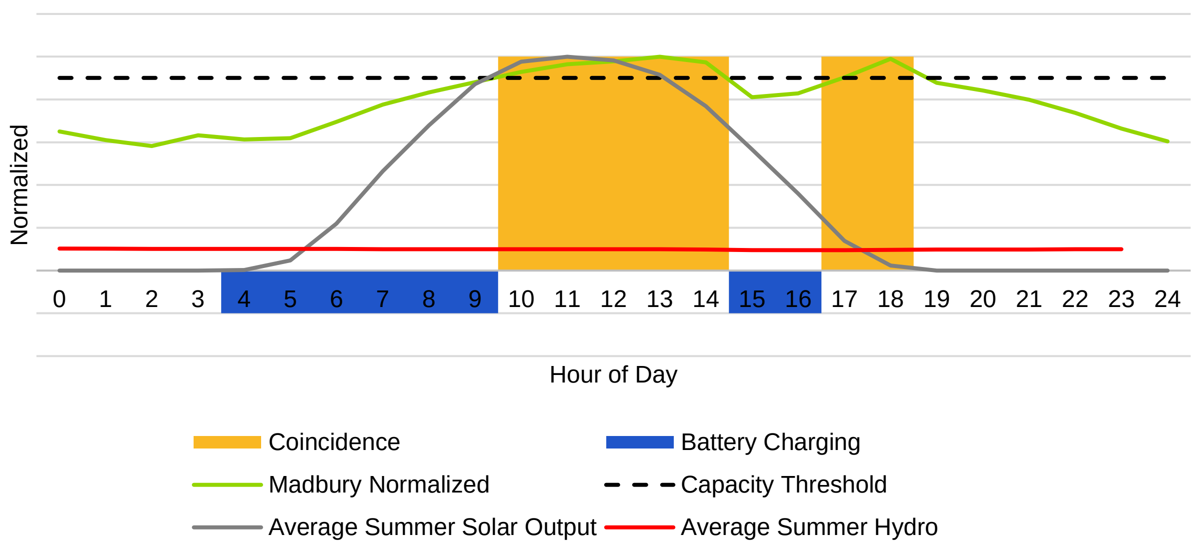


Source: Guidehouse, EDC data

Madbury ROW Circuit (34.5 kV) – Solar plus Storage plus Hydro Coincidence Analysis:

- The addition of hydro does little to further address the main period of need, given that it is highly coincident with solar production hours
- The late hours of need may benefit from solar plus storage and/or the addition of hydropower

Figure E-8. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Madbury Circuit (34.5 kV)



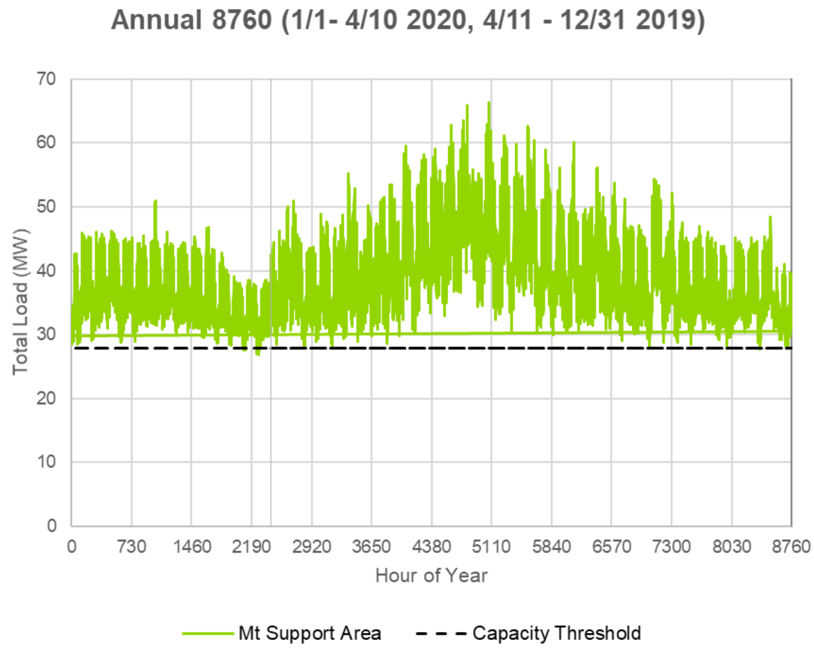
Source: Guidehouse, EDC data

Mount Support Substation (Bulk) DG Analysis Results

Mount Support Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Summer peaking substation with midday peak
- Historical project with normal and emergency overloads
    - Normal loading in excess of ratings for three feeders, one transformer, and one supply line
    - Emergency loading in excess of ratings for three transformers and four supply lines
- Mount Support load profile used as a proxy for the area in 2019-2020

Figure E-9. Capacity Deficiencies – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

Table E-2. Annual Load Profile and Capacity Threshold – Mount Support Substation (Bulk)

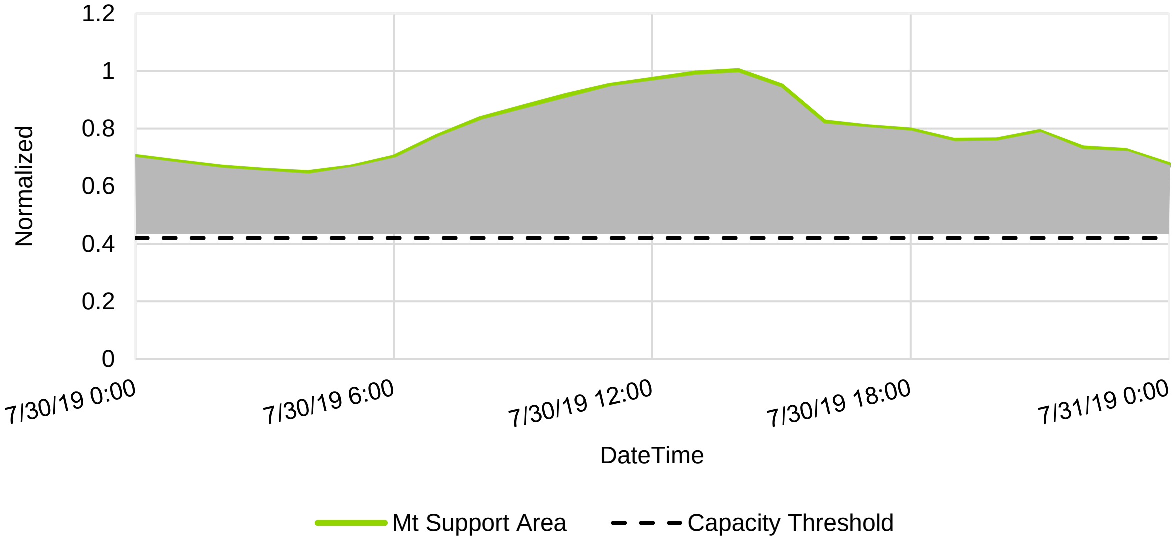
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Mount Support Substation (Bulk)	**Lebanon**	**66.4**	**7/30/19 14:00**	**Prior 2014**

Source: Guidehouse, EDC data

Mount Support Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Summer peaking substation with midday peak
- Deficiencies occur over the entire peak day due to significant (N-1) contingency exposure on substation transformer with low capacity rating
- Hours of capacity deficiency on peak day: 24

Figure E-10. Peak Day Load – Mount Support Substation (Bulk)

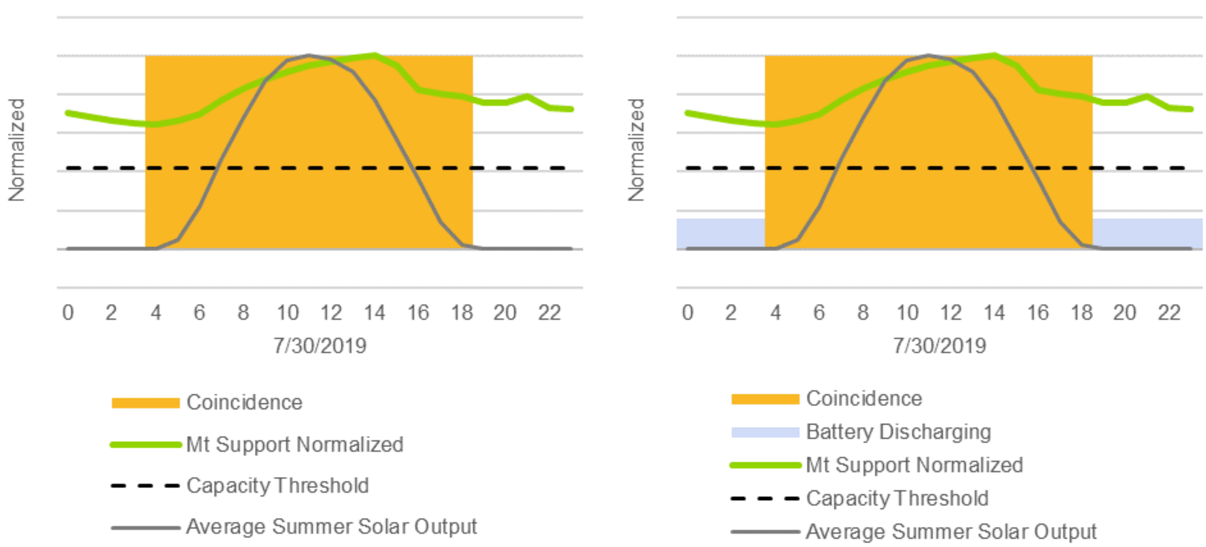


Source: Guidehouse, EDC data

Mount Support Substation (Bulk) – Solar Coincidence and Solar plus Storage Charging Analysis:

- Summer coincidence for 15 out of 24 hours.
- 15 hours of solar production vs. 24 hours of distribution capacity needs
- Limited or no charging opportunity for storage on peak day

Figure E-11. Solar Coincidence and Solar plus Storage Charging Analysis – Mount Support Substation (Bulk)

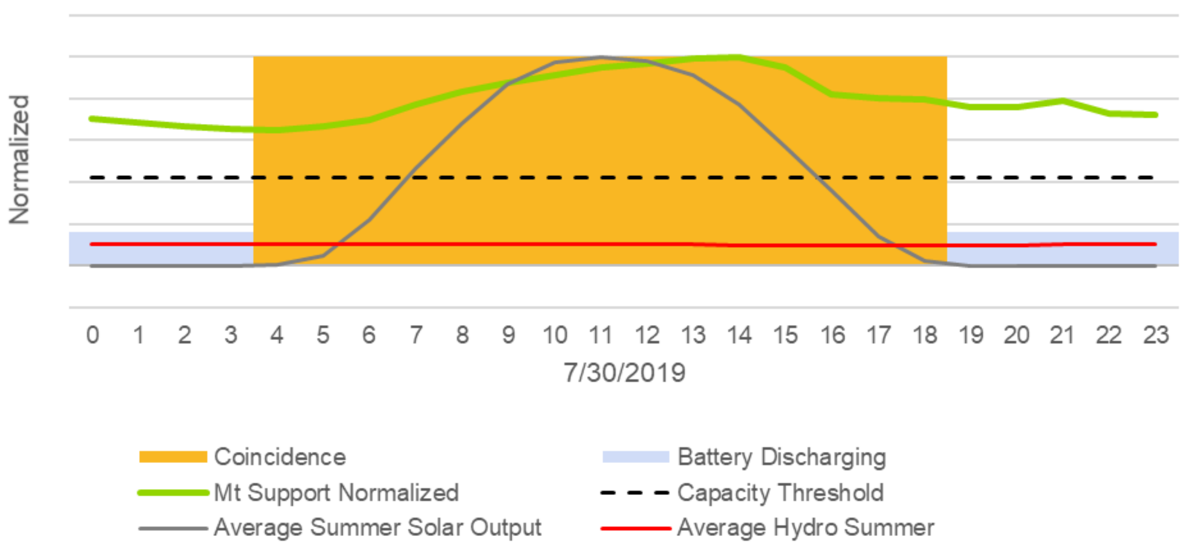


Source: Guidehouse, EDC data

Mount Support Substation (Bulk) – Solar plus Storage plus Hydro:

- Adding hydro could help to meet the hours of need at Mount Support
- On average, even though hydro production is much lower in the summer it is consistent across the entire day on average
- This aligns well with the broad period of need at Mount Support on the summer peak day

Figure E-12. Solar Coincidence and Solar plus Storage plus Hydro – Mount Support Substation (Bulk)



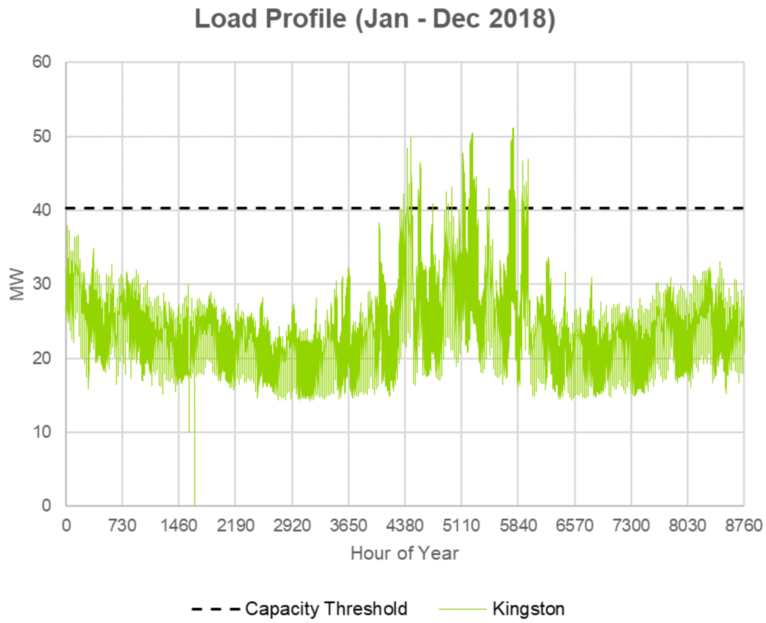
Source: Guidehouse, EDC data

Kingston Substation (Bulk) DG Analysis Results

Kingston Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Summer peaking location with normal overload
- Historical project with normal overload
- Annual 8,760 for year 2018
  - 2018 deficit: 10.7 MW
- Hours of capacity deficiency: 203
- Energy deficiency: 788 MWh
  - Approximately, 0.4% of total energy (211,733 MWh)

Figure E-13. Capacity Deficiencies – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

Table E-3. Annual Load Profile and Capacity Threshold – Kingston Substation (Bulk)

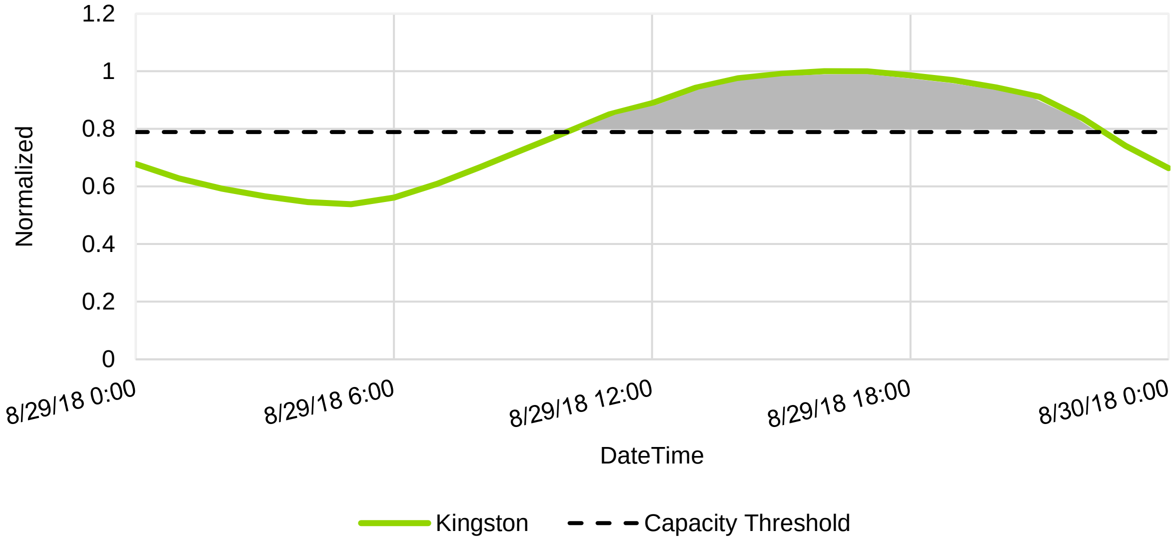
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Kingston Substation (Bulk)	Seacoast	51	8/29/18 17:00	Prior 2014

Source: Guidehouse, EDC data

Kingston Substation (Bulk) – Annual Peak Day and Capacity Threshold:

- Kingston is a summer peaking location with normal overload
- The load profile is smooth given that we are using the seacoast region hourly loads
- Hours of capacity deficiency on peak day is relatively high: 12

Figure E-14. Peak Day Load – Kingston Substation (Bulk)

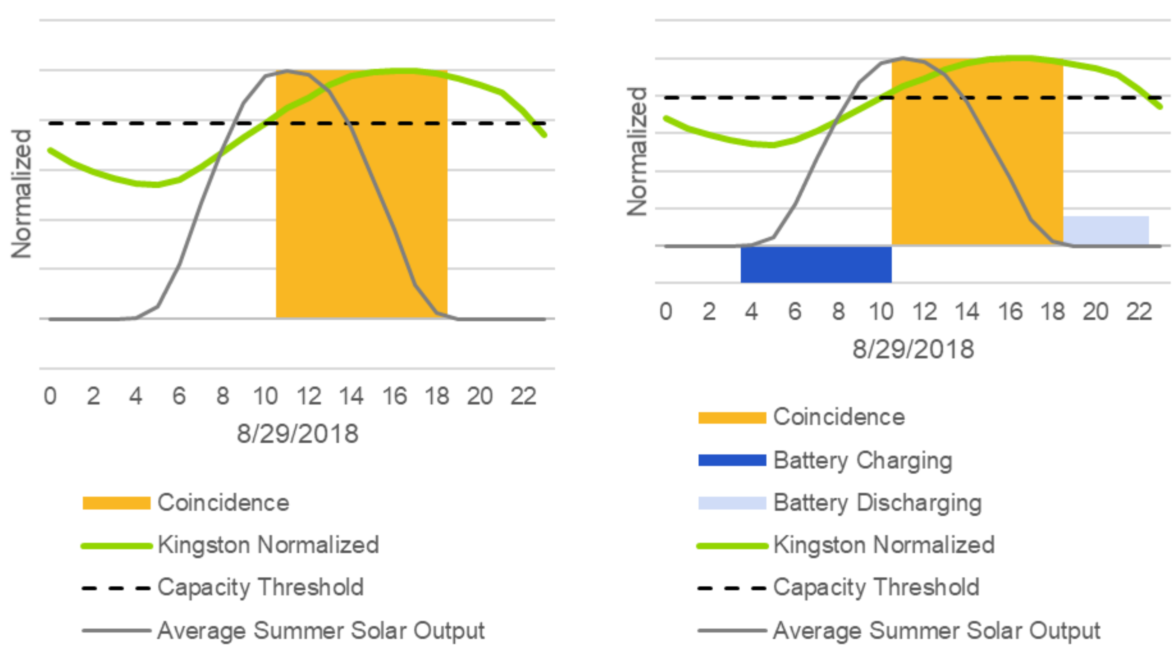


Source: Guidehouse, EDC data

Kingston Substation (Bulk) – Solar Coincidence and Solar plus Storage Charging Analysis:

- Summer coincidence interval: 8 out of 12 hours
- Summer 7-hour charging interval, 4-hour discharge interval

Figure E-15. Solar Coincidence and Solar plus Storage Charging Analysis – Kingston Substation (Bulk)

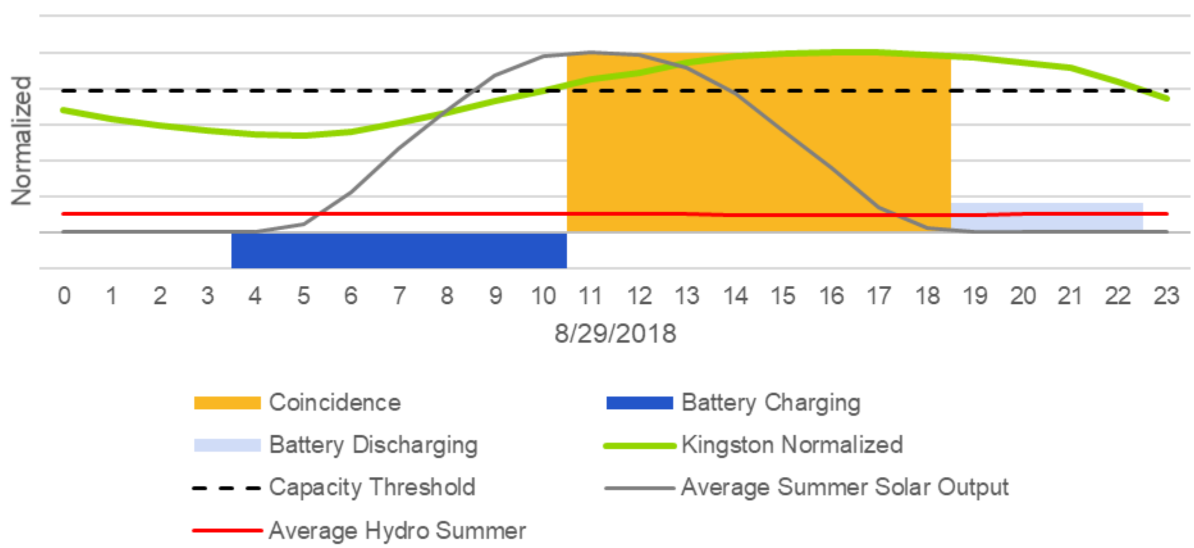


Source: Guidehouse, EDC data

Kingston Substation (Bulk) – Solar plus Storage plus Hydro Analysis:

- The peak hours later in the day could benefit from hydro production and reduce the size of any battery storage
- Based on the seacoast hourly profile, there are many hours of need that have either no coincidence or low solar PV production that could benefit from either battery storage or hydropower production

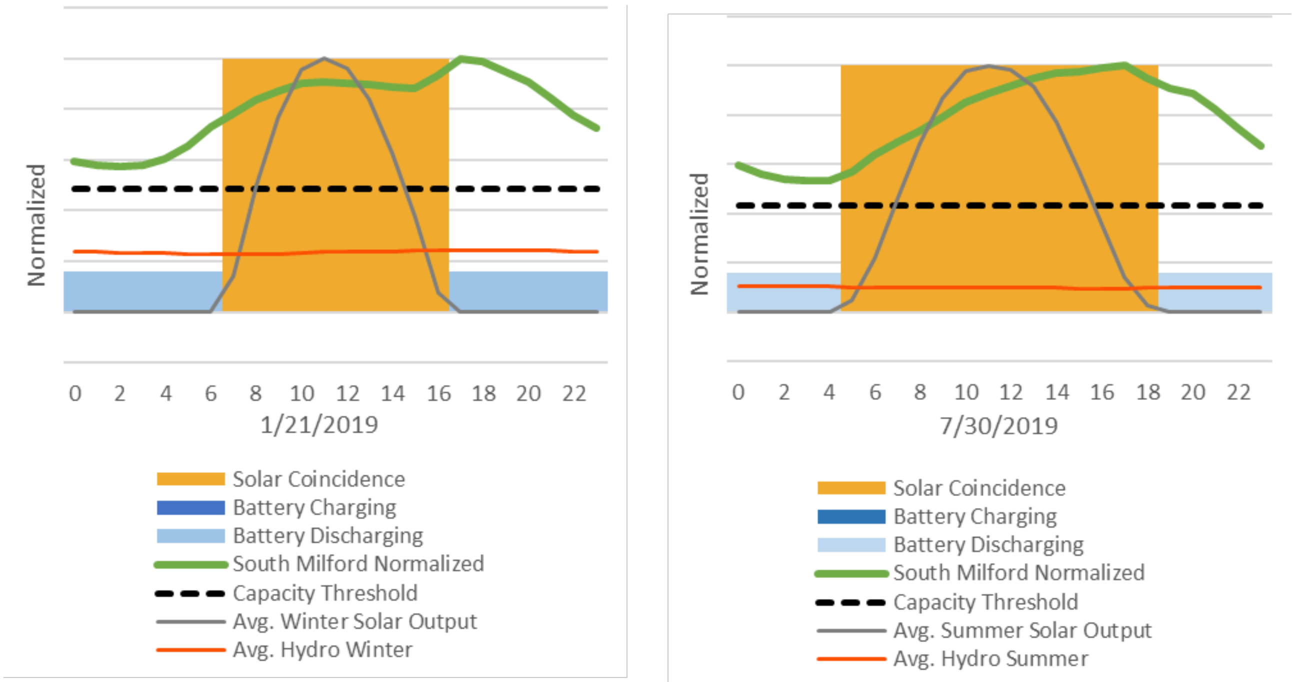
Figure E-16. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

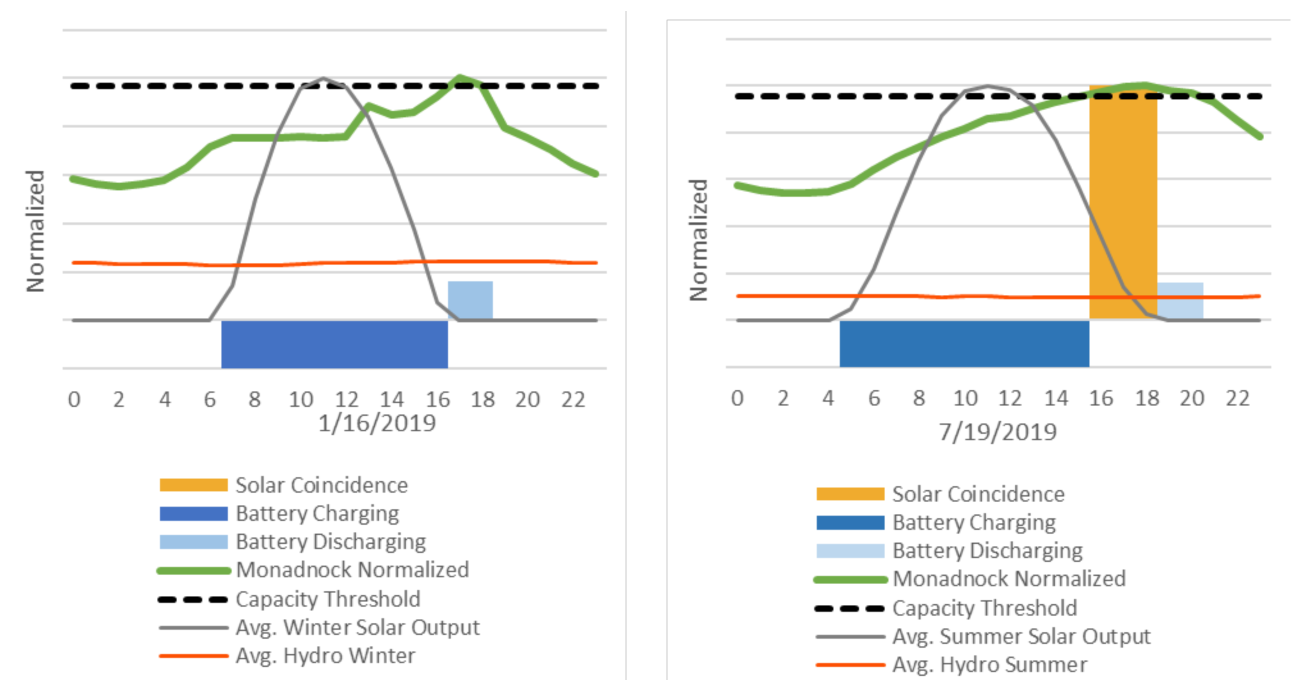
E.3 DG Production Profiles for Remaining 11 Sites

Figure E-17. Solar Coincidence and Solar plus Storage plus Hydro Analysis – South Milford



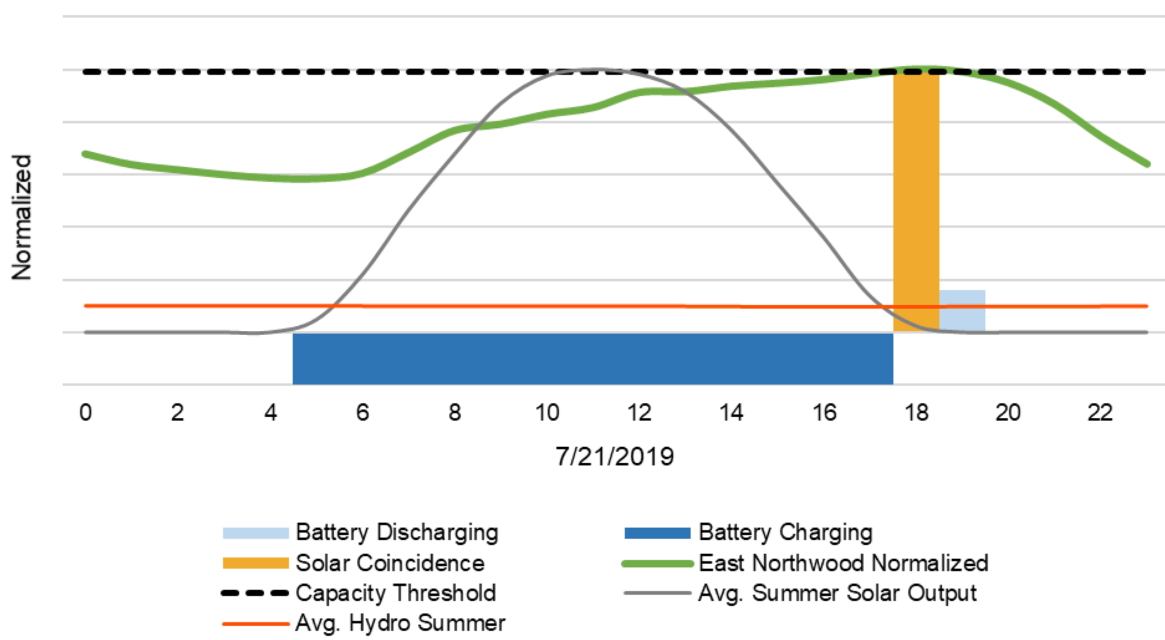
Source: Guidehouse, EDC data

Figure E-18. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Monadnock



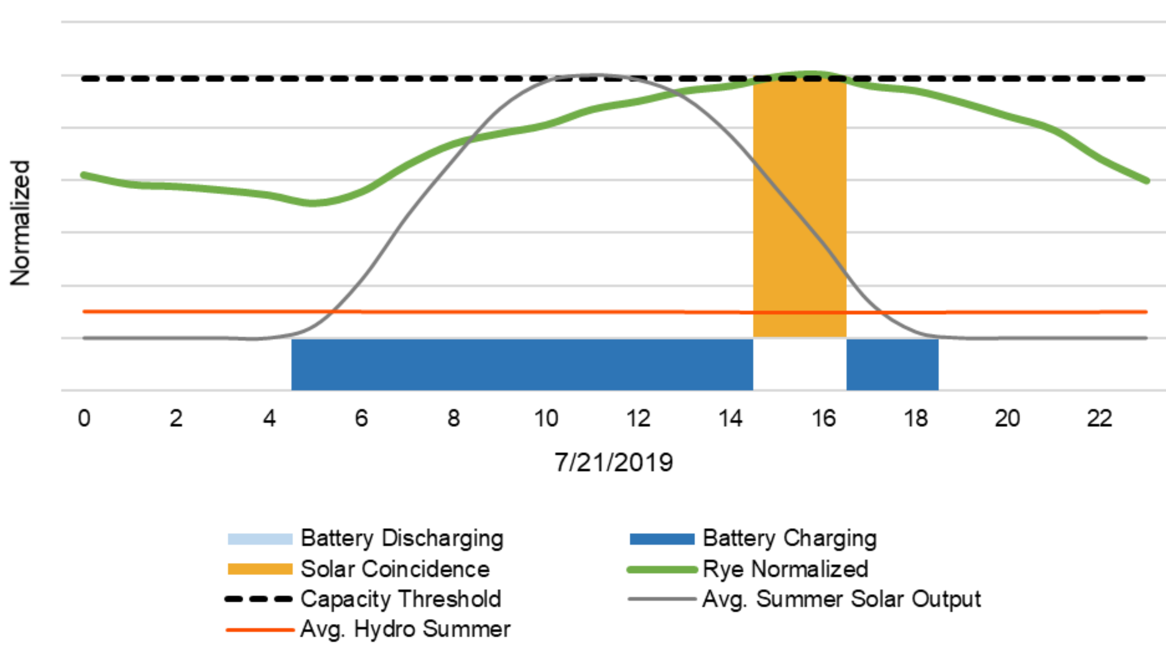
Source: Guidehouse, EDC data

Figure E-19. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – East Northwood (Non-Bulk)



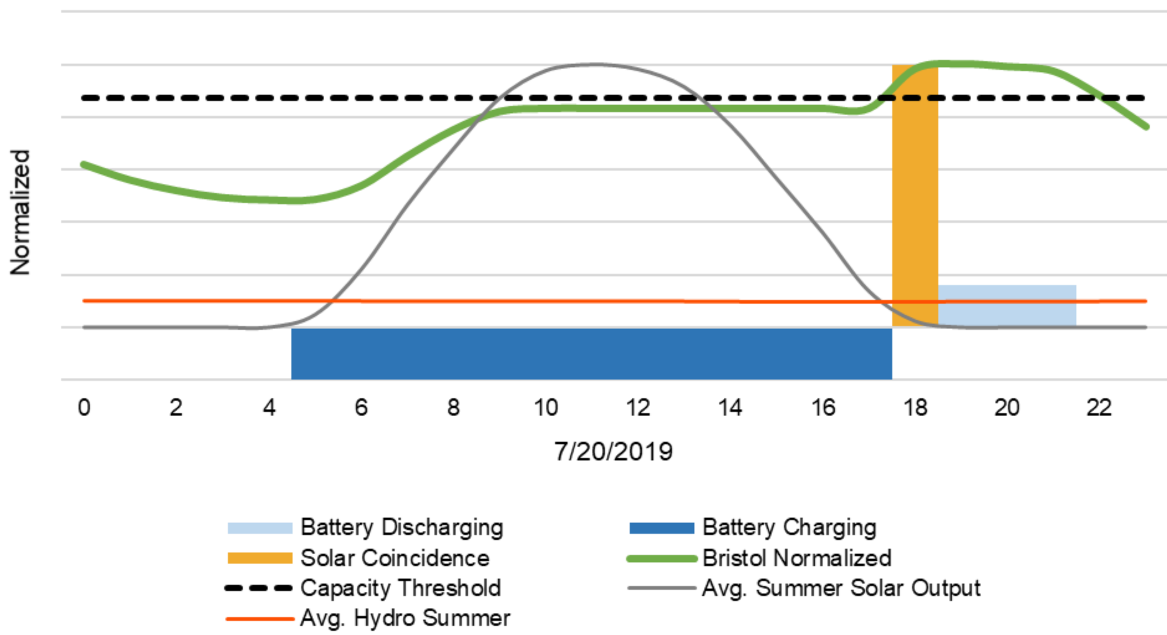
Source: Guidehouse, EDC data

Figure E-20. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Rye (Non-Bulk)



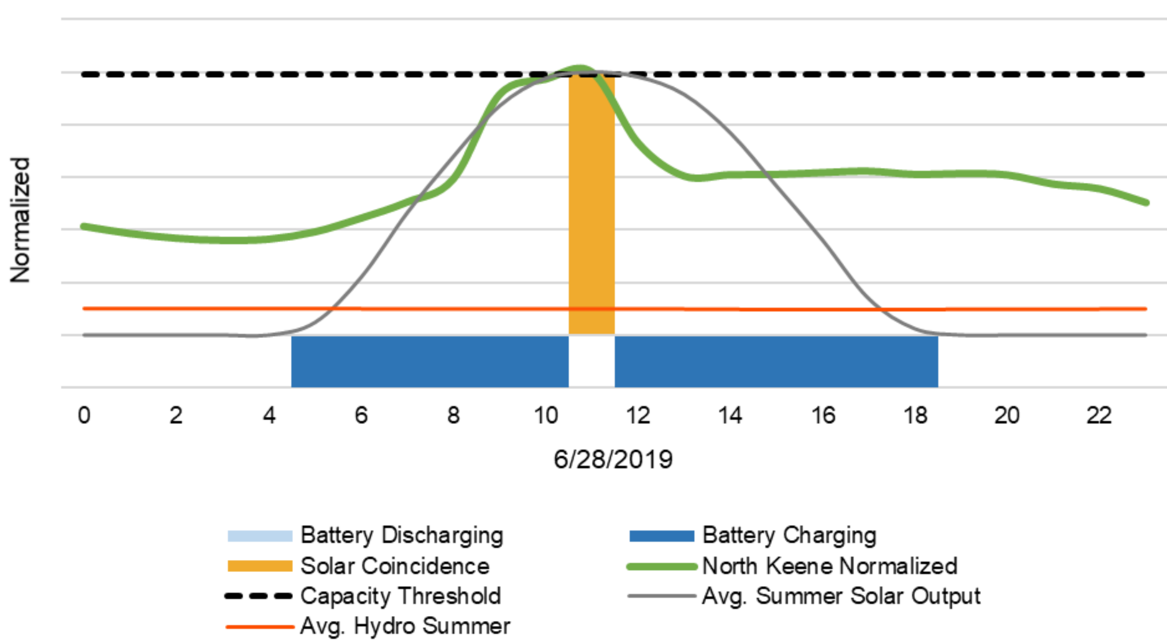
Source: Guidehouse, EDC data

Figure E-21. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Bristol (Non-Bulk)



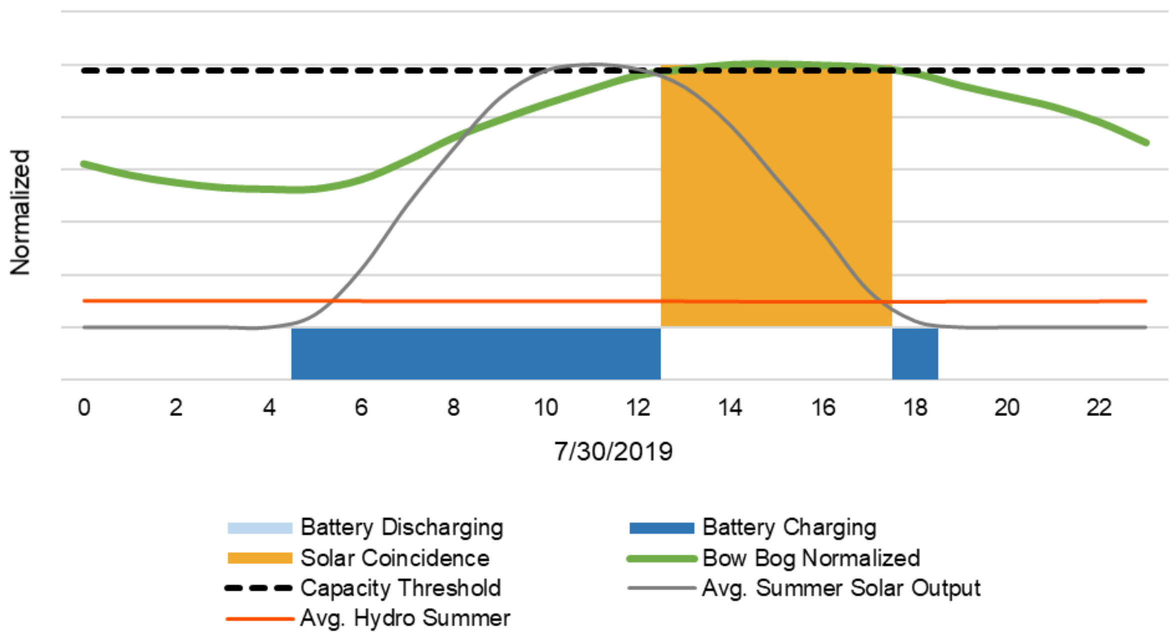
Source: Guidehouse, EDC data

Figure E-22. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – North Keene (12.47 kV)



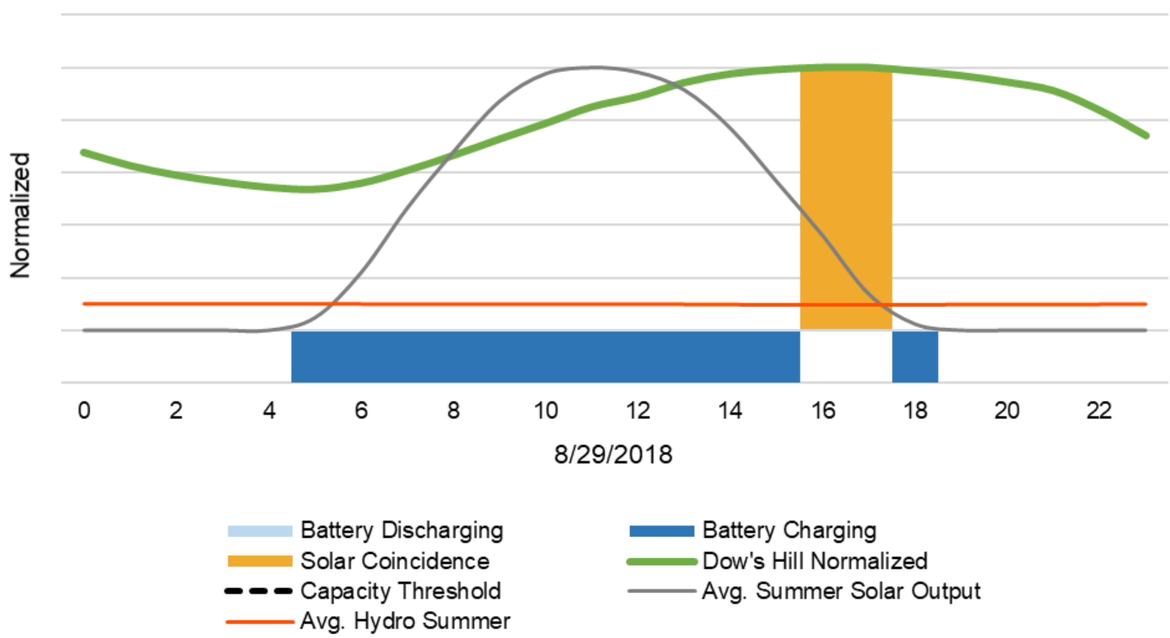
Source: Guidehouse, EDC data

Figure E-23. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Bow Bog (Non-Bulk)



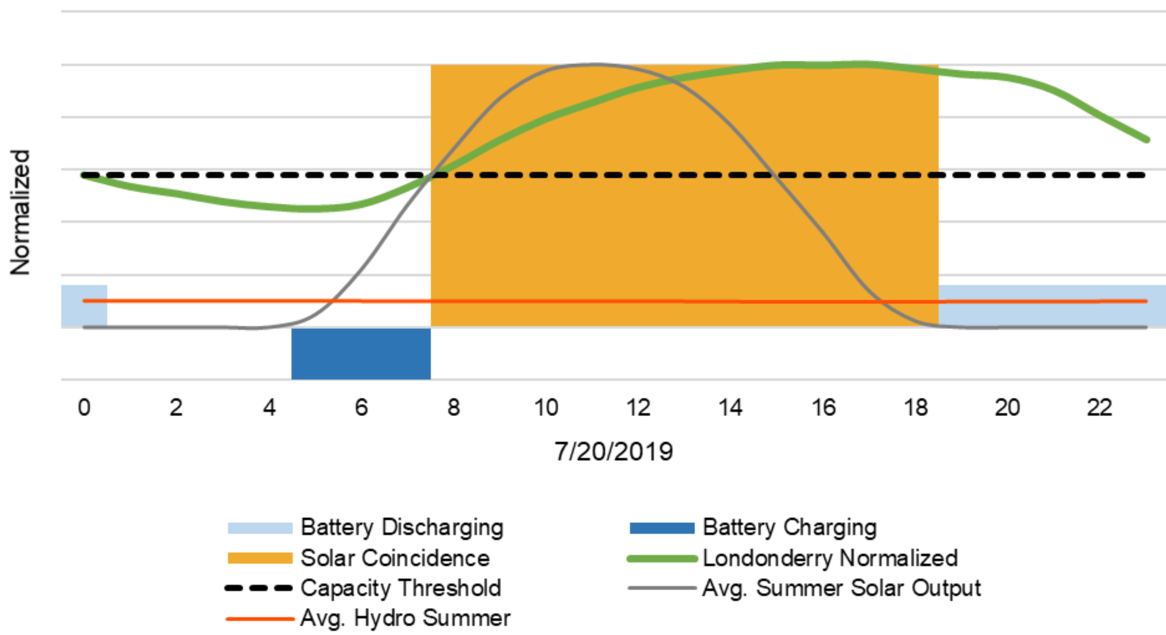
Source: Guidehouse, EDC data

Figure E-24. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Dow's Hill (Bulk)



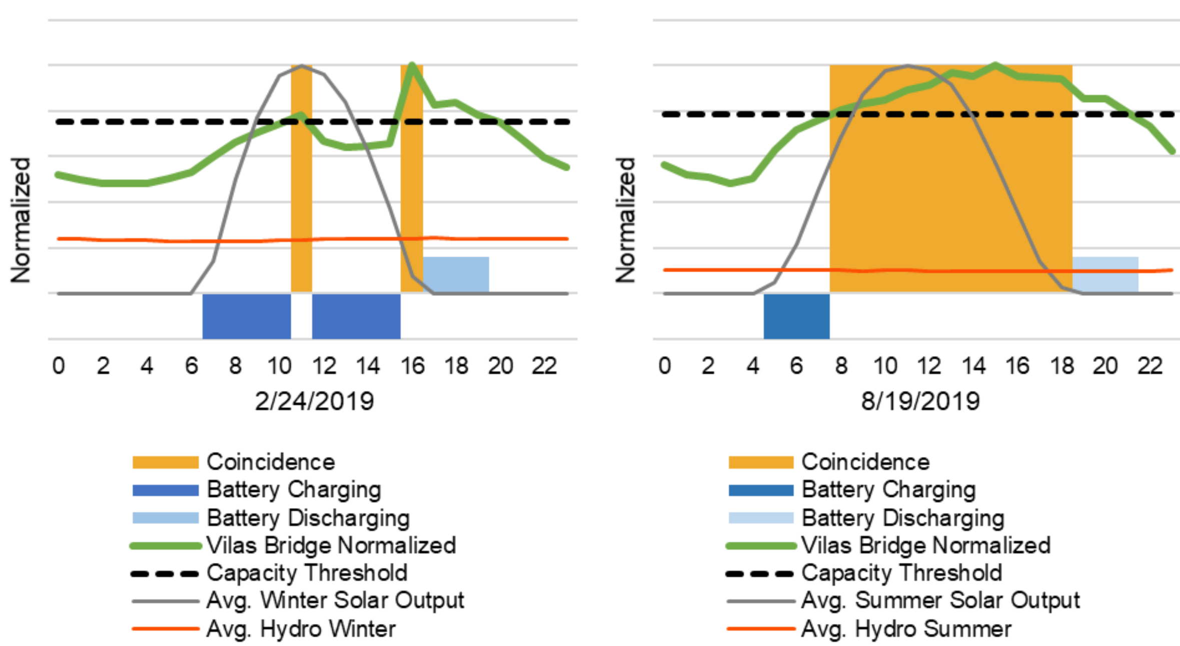
Source: Guidehouse, EDC data

Figure E-25. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Londonderry (34.5 kV)



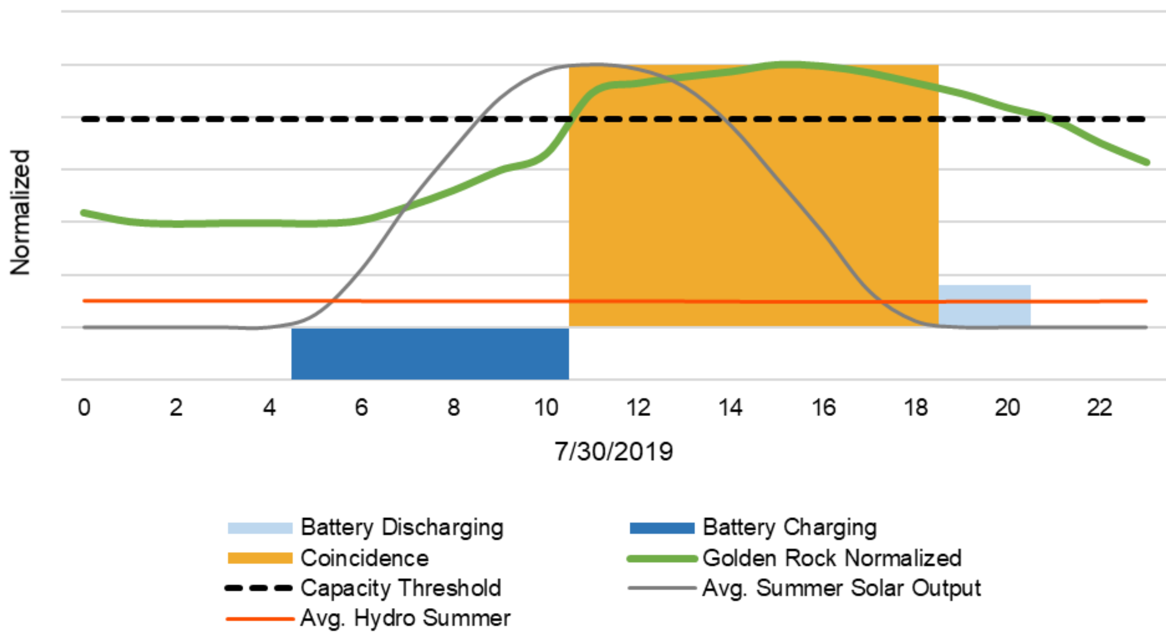
Source: Guidehouse, EDC data

Figure E-26. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Vilas Bridge (Non-Bulk)



Source: Guidehouse, EDC data

Figure E-27. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Golden Rock (Bulk)



Source: Guidehouse, EDC data

Appendix F. Glossary

F.1 List of Acronyms and Abbreviations

BEV: Battery Electric Vehicle

DER: Distributed Energy Resources

DG: Distributed Generation

EDC: Electric Distribution Company

EE: Energy Efficiency

EIA: Energy Information Administration

EV: Electric Vehicle

GW: Gigawatt

GWh: Gigawatt-hour

Hydro: Hydroelectric generation

ISO-NE: Independent System Operator New England

kV: Kilovolt

kW: Kilowatt

LCIRP: Least-Cost Integrated Resource Plan

LTE: Long-Term Emergency Rating

LVDG: Locational Value of Distributed Generation

MW: Megawatt

MWh: Megawatt-hour

MVA: Megavolt Ampere

NREL: National Renewable Energy Laboratory

NEM: Net Energy Metering

NWS: Non-Wires Solution

PSM: Physical Solar Model

PUC: New Hampshire Public Utilities Commission

PV: Photovoltaic

RECC: Real Economic Carrying Charges

ROW: Right-of-Way

SCADA: Supervisory Control and Data Acquisition

STE: Short-Term Emergency Rating

TFRAT: Transformer Rate on Non-bulk Transformers (Eversource)

Tx: Transmission

T&D: Transmission and Distribution

VDER: Value of Distributed Energy Resources

VASTTM: Vehicle Adoption Simulation Tool

Xfmr: Transformer

F.2 Glossary of Terms

Bulk Substation: Served by 115 kV transmission on high voltage side of substation transformer

Circuit: Refers to distribution circuits, used interchangeably with “feeder”

Commission: New Hampshire Public Utilities Commission

Capacity Deficiency: Condition under which the electric demand on a line or substation transformer exceeds normal or emergency ratings

Energy Deficiency: The total annual amount of energy, calculated by adding hourly capacity deficiencies, over an entire year

Feeder: Refers to distribution circuits, used interchangeably with circuit

Generation: Equipment and devices used to produce electricity; includes conventional, renewable, and energy storage devices

Guidehouse: Consultant that conducted the LVDG study and prepared this report with review by the Commission Staff

Hydro: Hydroelectric generation

Line: Refers to distribution circuits operating at voltages 34.5 kV and below, and sub-transmission lines up to 69 kV

Location: Indicates a geographic position on the EDCs’ electric system and is used extensively throughout the study to refer to substations, circuits, or sometimes other assets that are part of the electric delivery system. Location is synonymous with a place where utility assets are sited.

Non-Bulk Substation: Substation connected to transmission lines rated 69kV and below on high side of transformer

Output: Electric generation production, typically measured on an hourly basis

Staff: New Hampshire Public Utilities Commission Staff

Sub-transmission: Electric lines rated between 34.5 kV and 69 kV. Only sub-transmission lines rates 34.5 kV are included as potentially avoidable distribution capacity investments in the study; however, the impact of distribution level of investments is analyzed on sub-transmission lines rated up to 69 kV

Traditional Distribution Investments: Lines and substations electric utilities install to address capacity deficiencies; excludes renewable generation and energy storage

Violation: A condition under which EDC planning criteria is not met; usually refers to a capacity deficiency on lines or substation equipment

Appendix G. References

G.1 Report Sources

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2. New Hampshire LVDG Order approving study scope and timeline
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5. SCE RECC Slides
    - https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451488

Appendix H. List of Figures and Tables

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guidehouse.com

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SUMMARY

David Littell is an expert and attorney with more than 30 years of experience in energy, utility, and environmental regulation. The Chair of Bernstein's new Climate Practice Group, he is recognized attorney and national expert with expertise in energy and environmental regulation and markets, he provides valuable guidance to clients, public utility commissions, environmental regulators, and energy officials on how to approach and resolve complex energy, utility, pollution, environmental, and economic challenges. He has a keen understanding of market-based regulatory systems from electricity and gas to carbon trading as well as inter-state regulatory issues; electrical and gas ratemaking and rate design; renewable resource integration; demand response; efficiency and renewable portfolios; planning and assessment of energy and environmental resources; power, transmission, and non-transmission alternatives; gas local distribution company and interstate pipelines; approaches to air, water, land, and cross-media pollution control, and the intricacies of greenhouse gas mitigation and adaptation to climate change. He also has an extensive background on natural resources regulation of bird, amphibian, and aquatic habitats; toxics regulation; and product stewardship.

EDUCATION

Harvard Law School, J.D.,1992, *cum laude*
Princeton University, A.B., 1989, concentration in the Princeton (former Woodrow Wilson) School of Public and International Affairs, *magna cum laude, Phi Beta Kappa*.

PROFESSIONAL EXPERIENCE

2019-present, Bernstein, Shur, Sawyer & Nelson Law Firm — Portland, Maine
Shareholder, Chair of the Climate Practice Group

Attorney Littell represents clients in front of public utilities commissions on electric and gas matters including work on gas supply and balancing arrangements, transportation customer gas contracts, and related gas and electric peak system balancing and electrical system reliability. He also represents and counsels' utilities, merchant transmission developers, renewable energy developers and other clients in commission and utility matters. He has presented testimony before the FERC, the Maine PUC, the NH PUC, the RI PUC, the CT PURA, the MD PSC, the PUCO, the D.C. PUC, the U.S. EPA, the U.S. House of Representatives, state legislative committees and commissions. In addition to those agencies and decision-makers listed above, he has advised the MA DOER, the NH PUC, the Maine PUC, the RI PUC, the NJ BPU, the MI PSC, the MO PSC, and the MN PUC PSC.

2015-2022, Regulatory Assistance Project (RAP) — Portland, Maine
Principal & Senior Advisor

With RAP as a client of Bernstein Shur since 2019, Mr. Littell continues his national work on a broad range of rate design and energy innovation strategies with state officials and utility commissions. He advises state commissioners on rate design and pilots and data consideration related to grid modernization. He also advises commissions and energy offices on power sector transformation, energy efficiency, energy sector technology adoption, distributed energy resource integration, energy efficiency, and the integration of variable renewable energy sources. Mr. Littell has worked with utility regulators, energy regulators and environmental regulators from

20 states providing formal and informal advice on market design, regulatory and program design, and power sector transformation issues. Mr. Littell is the RAP lead on ISO/RTO energy, capacity, and other market design issues for the ISO-NE, NYISO, PJM, and MISO regions.

2010-2015, Maine Public Utilities Commission **Hallowell, Maine**
Commissioner
During his five-year tenure, Mr. Littell was a member of the three-person commission which resolved more than 2,000 cases involving ratemaking, rate design, energy efficiency, renewable energy, distributed generation, electric vehicles, and consumer protection issues. He also played a pivotal role in designing, implementing, and running North America's first market-based greenhouse gas regulatory system, the Regional Greenhouse Gas Initiative. He was an officer of the initiative from 2008 through 2015, serving as chair, vice chair, and treasurer, and taking the lead on policy, operations, and management of the nine-state organization. During his term as commissioner, he also served as vice chairman of the National Association of Regulatory Utility Commissioners' Task Force on Environmental Regulation and Generation. He chaired the energy zone group of the Eastern Interconnection States Planning Committee, which developed the energy zone mapping tool for energy resources across the 38 eastern states.

2005-2010, Maine Department of Environmental Protection **Augusta, Maine**
Commissioner
Mr. Littell led Maine's DEP to approve more investments in Maine's capital base (energy-related, pulp & paper, major industrial and commercial) than any other Maine commissioner before or since while leading environmental protection improvements in Maine's and regional programs. Mr. Littell implemented significant initiatives to address climate change, including the Regional Greenhouse Gas Initiative and Maine's Climate Action Plan to reduce greenhouse gas emissions to 1990 levels by 2010 and 10 percent below 1990 levels by 2020. Maine met the 2010 goal early and is on track to meet the 2020 reduction goal.

At DEP, he managed and led 415 environmental scientists, engineers, environmental and financial specialists, with a budget of roughly $80 million (which he cut 14 times in office while maintaining staff morale). He also served as the environmental expert within the Governor's Cabinet for economic development projects and represented Maine on a numerous regional and national associations and initiatives. He designed and implemented protections for Maine's most significant wildlife and bird habitats as well as aquatic habitats under the Natural Resource Protection Act and the water withdrawal programs. Mr. Littell designed and implemented nation-leading consumer toxic protections in Maine's Kid-Safe Products Law, working closely with Washington State officials on parallel initiatives. While instituting innovative environmental programs, he worked with the Economic Development Department to maintain and expand Maine's economic base through permitting a record amount of capital investment in the state, largely in the energy sector, ranging from wind and tidal projects to large-scale transmission and industrial co-generation.

2003-2005, Maine Department of Environmental Protection **Augusta, Maine**
Deputy Commissioner
Mr. Littell was the chief operating manager for the agency, where he oversaw a budget of $55 million in spending, with $88 million in authority, and operations with a staff of 463 (reduced to 415 by 2010) in three bureaus and 14 divisions. He was the point of contact within the Administration on adoption of the California low-emission vehicle, partial zero-emissions vehicle, and Pavley standards, and managed those processes within the agency and with stakeholders.

He served as the lead economic development and permitting contact within the Administration for major capital and priority projects. He also oversaw Maine's role in the Base Realignment and Closure process. Mr. Littell coordinated with economic development officials to expand and maintain Maine's industrial base, sustaining more than 8,000 at-risk jobs and expanding Maine's commercial and industrial base through the Great Recession.

1992-2003, Pierce Atwood Law Firm **Portland, Maine**
Partner and Attorney
Mr. Littell specialized in project permitting, land-use, environmental litigation, and complex multi-party negotiations with the U.S. Environmental Protection Agency (EPA) and state agencies, hazardous waste cleanups, and wireless communications. He litigated in U.S. District and Maine courts successfully for clients. He acted as lead counsel on the EPA Superfund and hazardous substance sites in a national-precedent-setting settlement resulting in successful liability transfer and site cleanups under his multi-party management. This included negotiating an innovative hazardous waste settlement with the EPA, the U.S. Department of Justice, and hundreds of parties who transferred cleanup obligations to a third party for a cash-out settlement payment. He represented companies spanning from Fortune 50 corporations, leading U.S. telecommunications companies, high-tech and older manufacturing companies, all 13 of the pulp and paper mills in Maine to developers, municipalities, and individuals.

1994-2004 United States Navy Reserve
Lieutenant Commander
Mr. Littell served in the United States Navy Reserve, resigning as a Lieutenant Commander. He served as an intelligence officer with Combat Patrol Squadron 92 (VP-92), U.S. Navy Reserve squadron, and the Tactical Support Center at Brunswick Naval Air Station. He also served in Atlantic Intelligence Command and Joint Forces Command units based in South Weymouth, Massachusetts, and Devens, Massachusetts. He was awarded two individual Navy Achievement citations, expert rifle and pistol shot, and a number of unit citations for his service.

SELECTED RECENT PROJECTS
Regulatory Structures and Market Design

- Mr. Littell is advising the Rhode Island Public Utilities Commission, the Maryland Public Service Commission, the Connecticut Public Utilities Regulatory Authority, the Minnesota Public Utility Commission, and the Michigan Public Service Commission on adoption of performance-based regulation. He has also advised the Pennsylvania Public Utilities Commission and the Ohio Public Utilities Commission on implementation of performance-based regulation.
- Mr. Littell has presented testimony to the U.S. Congress, the U.S. Environmental Protection Agency, and the U.S. Federal Energy Regulatory Commission (FERC). He has also participated in workshops and negotiations with regulators from dozens of U.S. states, six Pacific Rim nations, the U.K. and the UNFCC COP in Copenhagen.
- He has developed an expertise in regulatory approaches to modern data management systems necessary to manage utility transitions to advanced energy markets, and how to set up those market and regulatory rules to facilitate competitive markets.
- Mr. Littell played a pivotal role in designing, founding, successfully launching, and managing the Regional Greenhouse Gas Initiative (RGGI), the first North American regulatory program for greenhouse gas reductions. The market-based program successfully put in place rules coordinated with ten initial states through a centralized administrative and technical assistance entity known as RGGI, Inc., based in New York City. He was an officer and the primary operational officer for seven years, overseeing and managing the staff and financial operations of the multibillion-dollar RGGI market.

Rate, Net Metering, and Program Design

- Mr. Littell has advised and trained more than a half-dozen commissions on rate design and related power sector transformation issues. He focusses his rate design consulting and advice on issues associated with integration of smart grid and advanced energy technologies that all jurisdictions are facing today.
- He advised the New Hampshire Commission on multiple dockets that involve rate design considerations and presented testimony to the New Hampshire Decoupling Commission created by the New Hampshire Legislature to examine the benefits of rate decoupling. David acted as commission adviser in both New Hampshire's Grid Modernization Docket and New Hampshire's 2016-2017 Net Energy Metering Dockets both of which considered and involved rate design to send consumer price signals more effectively. His work continues with advice on pilots and studies emerging from these dockets.
- He is advising the Maryland Public Service Commission on advanced rate-design issues and co-chairing the rate design workgroup in the Public Conference-44 Maryland grid modernization docket.
- Mr. Littell is advising the Connecticut Department of Energy and Environmental Protection on rate design issues associated with proposals for advanced distributed energy resource pilots, and other commissions and state departments on dynamic pricing design.
- He performed rate design training for commissioners and staff of the New Brunswick Energy and Utilities Board and Department of Energy and Resource Development, the Prince Edward Island Regulatory and Appeals Commission, the Newfoundland & Labrador Board of Commissioners of Public Utilities, and the Nova Scotia Utility and Review Board.
- While on the Maine Public Utilities Commission, Mr. Littell participated in and decided rate cases for each of the three investor-owned electrical utilities in Maine and three natural gas companies. Those rate cases, particularly fully litigated cases, were rare, in general occurring once per decade. The cases he decided involved many of the issues facing other commissions nationally and internationally, including rate design, demand-charge, standby fees, and fixed fee proposals among other issues.

Natural Gas Proceedings

- Mr. Littell represents Bucksport Generation, a dual-fueled fast-start gas power plant in a general LDC rate case in Docket. 2021-00024 case involving considerations of impacts of LDC and interstate pipeline tariffs and charges on power plant operations.
- Mr. Littell successfully represented Bucksport Generation in matters in front of the Maine PUC including in Bangor Gas's tariff revision in Docket 2019-000284 to negotiate specific tariff revisions and provisions related to draw tolerances, imbalance, and nomination provisions of Bangor Gas's tariff.
- Mr. Littell has represented a number of state agency confidential clients in consultative relationships involving at least a dozen different matters in front if various state commissions.
- Mr. Littell sat on and ruled on tariff and cost-of-gas cases for each of Maine's three gas local distribution utilities from 2010 to 2015 include capacity acquisitions for transportation and supply provisions for each gas utility.

Power Sector Transformation

- Mr. Littell presented on U.S. regulatory and power market innovations to the U.K. Office of Gas and Electricity Markets (OFGEM) in September 2018.
- Mr. Littell is advising the New Hampshire Public Utilities Commission and staff in its Grid Modernization docket. The docket considers distributed energy resources, time of use rates, distribution grid infrastructure and data needed for modern utility-side and

consumer-side energy management. Mr. Littell chaired a Data Management Workgroup for the NH Grid Modernization Stakeholder Group which considered data management needs of a modern grid and presented recommendations to the full stakeholder group which were adopted by the full stakeholder group.

- Mr. Littell is currently addressing information management and communications issues associated with smart grid implementation, decoupling, and similar mechanisms to facilitate distributed energy resources in different forums and proceedings. He highlights these issues in national fora, including the National Governors Association and the National Smart Grid and Climate Summit, and advises state officials, such as the New Hampshire Legislative Decoupling Commission, the New Hampshire Public Utilities Commission, and other commissions, energy offices, and environmental officials in other states.
- Mr. Littell is advising the Maryland PSC and stakeholders on PC-44 issues including rate design, pilot design, value of solar study scoping issues, and working with other workgroups on competitive markets and suppliers, electric vehicles, interconnection, and other issues. He has facilitated the discussions of the rate design workgroup and participated in meetings with stakeholders individually and collectively.

Energy Efficiency

- Mr. Littell advised the New Hampshire Public Utilities Commission's stakeholder effort to consider establishing an energy efficiency resource standard. The stakeholder effort was with all of New Hampshire's electric and natural gas utilities, as well as energy efficiency and environmental advocates. The successful stakeholder effort transitioned to a formal adjudicatory docket to consider adoption of an energy efficiency resource standard in New Hampshire and culminated in adoption of the first New Hampshire Energy Efficiency Resources Standard in 2016.
- Mr. Littell participated in the Maine Public Utilities Commission's review and oversight of the Efficiency Maine Trust, including approval of the first two three-year energy efficiency triennial plans. These first two triennial plans increased Maine's funding levels for residential, commercial, and industrial energy efficiency programs. The first triennial plan proceeding was significant in that it represented a review of the newly established trust structure legislated by the Maine legislature in 2009.
- While on the Maine Public Utilities Commission, Mr. Littell dissented from efforts to place an artificially low cap on energy efficiency funding in two 2015 decisions. His dissenting view of the proper interpretation of the energy efficiency cap was subsequently legislated in 2015 by large bipartisan majorities, overruling the Governor's veto to legislatively maintain an adequate funding cap for Maine's energy efficiency programs.

Renewable Energy

- Mr. Littell is advising a state commission and stakeholders in two different states on value of solar, and solar energy regulation.
- On the Maine Public Utilities Commission, Mr. Littell wrote extensively on the value of investments in grid-scale renewables to diversify the supply and generation mix. He participated in approval of four wind power purchase contracts, including an offshore wind contract. He also focused on the benefits, costs, and risks of investments in other grid-scale resources, including natural gas.
- Mr. Littell participated in state efforts to assess the value and impact of increased levels of renewable distributed generation in New England on the capacity resource markets. These included state efforts to have independent system operator ISO-New England reduce the installed capacity requirement due to state investments in energy efficiency and distributed solar resources.

Distributed Generation and Distributed Energy Resources

- Mr. Littell advised the state of Connecticut on distributed energy resources, including storage, under Connecticut's new policy framework on battery storage proposals.
- He has advised multiple state commissions on incorporating distributed energy resources (DERs) at higher levels than previously into commission and utility processes including hosting capacity analysis, interconnection processes, and areas to consider for integration of higher levels of DERs at the distribution level.
- Mr. Littell is participating in the Evolution of Demand Response Project examining the role of distributed generation and distributed energy resources (DER), including opportunities and challenges for DER resources, given the current legal, economic, and regulatory context. The EDP Project issued *Demand Response, the Road Ahead* in early 2016.

Resource Planning and Power Market Design

- As part of the Eastern Interconnection States Planning Committee, Mr. Littell participated in a detailed examination of the integration of renewable energy, energy efficiency, and other advanced technologies. The committee evaluated 72 different scenarios showing alternatives for the development of energy resources and transmission in the 38 eastern U.S. states.
- Mr. Littell examined in depth the impacts of overreliance on natural gas-fired generation in New England and consequential costs and risk to New England ratepayers.
- He is assisting state officials with consideration of market designs proposed for capacity and other markets in multiple ISO/RTOs including efforts to integrate state public policies and regional markets.

Air Quality and Climate

- Mr. Littell played a pivotal role in designing, launching, successfully implementing, and managing the Regional Greenhouse Gas Initiative (RGGI), the first North American regulatory program for greenhouse gas reductions. The market-based program successfully put in place rules coordinated with ten initial states through an administrative and technical entity known as RGGI, Inc., based in New York City. He was a chairman and officer and the primary operational officer for seven years, overseeing and managing the staff and financial operations of the multibillion-dollar RGGI market.
- Mr. Littell implemented the Maine Air Toxics Initiative, which established a regulatory and policy framework to address the more than 180 air toxics listed, but thereto not regulated, under the Clean Air Act. This included toxicity weighted emissions factors based on the most current scientific toxicity data and engineering factors. The top policy recommendation put in place to reduce air toxic emissions was to pursue commercial, industrial, and transportation-related efficiency.
- Mr. Littell initiated and implemented a mercury emissions cap for stationary air sources in Maine.
- As Maine's environmental commissioner, Mr. Littell facilitated the East Coast and Mid-Atlantic States development of Regional Haze Standards as chair of the Mid-Atlantic/Northeast Visibility Union, including leading interregional consultations with states in the Midwest and Southeast. These standards resulted in significant reductions of particulate and sulfate compound pollution in East Coast and upwind states, including the Midwest and Southeastern United States.

SELECTED PROCEEDINGS

- Mr. Littell has advised the Maryland PSC's PC-44 docket and its five active workgroups

- Mr. Littell has advised the New Hampshire PUC for five years in three dockets including their Grid Modernization and 2016-2017 Net-Energy Metering dockets and follow-on proceedings.
- Mr. Littell is leading a team advising the Connecticut Public Utilities Regulatory Authority in grid modernization, rate design and energy resource evaluation.
- In the last three years, he has advised public utility commissions, energy offices, environmental agencies, Governor's Offices, and/or Attorney General's offices on energy and environmental issues in 17 states: New Hampshire, Rhode Island, Connecticut, Massachusetts, Maine, New York, Maryland, New Jersey, Pennsylvania, Virginia, Michigan, Ohio, Minnesota, Missouri, Oregon, and California.
- Mr. Littell played a pivotal role in designing, founding, successfully launching, and managing the Regional Greenhouse Gas Initiative (RGGI), the first North American regulatory program for greenhouse gas reductions. The market-based program successfully put in place rules coordinated with ten initial states through a centralized administrative and technical assistance entity known as RGGI, Inc., based in New York City. Mr. Littell was an officer and the primary operational officer for seven years, overseeing and managing the staff and financial operations of the multibillion-dollar RGGI market.
- Mr. Littell participated in the Maine Public Utility Commission's review and oversight of the Efficiency Maine Trust, including approval of the first two three-year energy efficiency triennial plans. These first two triennial plans increased Maine's funding levels for residential, commercial, and industrial energy efficiency programs. The first triennial plan proceeding was significant in that it represented review of the newly established trust structure legislated by the Maine Legislature in 2009.
- As a Maine public utilities commissioner, Mr. Littell considered the value of energy efficiency investments. He dissented from efforts to place a low cap on energy efficiency funding in two 2015 decisions. His view of the proper interpretation of the energy efficiency cap was subsequently legislated in 2015 by wide bipartisan majorities, overruling the Governor's veto to legislatively maintain a higher cap for Maine's energy efficiency programs.
- On the Maine Public Utilities Commission, Mr. Littell participated in review of long-term contracts including approving wind power purchase contracts, including land-based wind projects and offshore wind contracts with Norway's Statoil and then the University of Maine's AquaVentus consortium. The AquaVentus approval is still operative, with the University of Maine project pursuing U.S. Department of Energy funding.
- On the Maine Public Utilities Commission, Mr. Littell also considered the benefits and costs of investments in other grid-scale resources, including land-based wind projects and natural gas:
    - He was part of a two-person majority to approve the Downeast Wind Project proposed by Apex Energy in 2013. In his concurrence, he noted he would have approved two additional wind projects based on reasonable cost-risk management.
    - He was part of a two-commissioner majority to approve a NextEra wind power project in 2014 and another two-commissioner majority to reaffirm that decision in 2015.
    - He was part of a two-commissioner majority to approve the Bowers wind power project in 2014, and later dissented from the commission's 2015 reversal of that decision.
    - In review of potential commission investments in natural gas pipeline inter-state capacity contracts, Mr. Littell both noted the need for new investments in natural gas and raised concerns with unnecessary state intervention in the competitive

markets to support a mature technology and long-term impacts on private investment in the capacity and energy markets.

- As Maine's environmental commissioner, Mr. Littell led the development of East Coast's Regional Haze Standards as chair of the Mid-Atlantic/Northeast Visibility Union. He led inter-regional consultations with states in the Midwest and Southeast. These multi-state standards required modifications of rules and requirements in more than 14 states as well as multiple upwind states, including legislative and rule changes in Maine.
- Mr. Littell oversaw the 2005 amendments to Maine's Natural Resources Protection Act and legislative rulemaking to implement protections for waterfowl, wading bird, shorebird, and vernal pool habitats in Maine. These rules extended Maine's habitat protections to protect the most valuable habitats on a statewide scale and involved bipartisan modifications to the regulatory structure in 2006 to address concerns with economic impacts of these rules. Due to the successful implementation of the significant wildlife habitat programs, subsequent repeated efforts to repeal these habitat protections have failed every year, including two years when the legislature was controlled by the same party as the subsequent Governor.
- Mr. Littell chaired Governor Baldacci's Task Force on Safer Chemicals in 2006, which led to a new regulatory approach and advanced legislation of Maine's Kids Safe Chemical Safety Law in 2007 and implemented the law, making Maine one of the leading U.S. states on consumer protection from toxics contained in consumer products. Under this law and related legislation, Maine banned bisphenol-A and two congeners of brominated flame retardants from consumer products and imposed restrictions on the use of cadmium, formaldehyde, mercury, nonylphenol, arsenic, and phthalates in consumer products.

SELECTED PUBLICATIONS

- David Littell, Camille Kadoch, Phil Baker, Ranjit Bharvirkar, Max Dupuy, Brenda Hausauer, Carl Linvill, Janine Migden-Ostrander, Jan Rosenow, and Wang Xuan of Regulatory Assistance Project; Owen Zinaman and Jeffrey Logan National Renewable Energy Laboratory

(2018). Next-Generation Performance-Based Regulation, 21st Century Power Partnership.

  - Volume 1, Global Lessons for Success: https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume1_april_2018.pdf
  - Volume 2, Essential Elements of Design and Implementation: https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume2_april_2018.pdf
  - Volume 3, Innovative Examples from Around the World: https://www.raponline.org/wp-content/uploads/2018/05/rap_next_generation_performance_based_regulation_volume3_april_2018.pdf

  **These papers are also published on NREL's website.

- David Littell and Jessica Shipley, (Aug. 2017) Performance-Based Regulatory Options, A White Paper for the Michigan Public Service Commission, https://www.raponline.org/wp-content/uploads/2017/08/rap-littell-shipley-performance-based-regulation-options-august2017_1.pdf.
- David Farnsworth, David Littell, D., Chris James, & Kelley Speakes-Backman. (2016). *RGGI Program Review: Model to Reduce Uncertainty in State Carbon Plans*. Montpelier, VT: The Regulatory Assistance Project.
- David Littell & David Farnsworth (2016). *Carbon Markets 101: "How to" Considerations for Regulatory Practitioners*. Montpelier, VT: The Regulatory Assistance Project.

- Littell, D. (2014, February). Putting a Price on Carbon: How EPA can establish a U.S. GHG Program for the Electricity Sector. *Public Utilities Fortnightly*.
- Littell, D., & Speakes-Backman, K. (2014, October). Pricing Carbon under EPA's Proposed Rules: Cost Effectiveness and State Economic Benefits. *The Electricity Journal*.
- Littell, D. (2013, October). EPA to Build on State Efforts to Move Toward a Cleaner Power Sector. Carbon Market North America. *Reuters Point Carbon News*, *8*(37).
- Littell, D., Westerman, G., & Burson, M. (2008, October). Confronting Global Warming, Maine's Multi-Sector Initiatives 2003-2008. *Maine Policy Review*.
- Littell, D. (2002). Why More is Required to Address Maine's Childhood Lead-Poisoning Problem. *Maine Policy Review*.
- Littell, D. (1993). Consent and Disclosure in Superfund Negotiations. *Harvard Environmental Law Review*.
- Littell, D. (1991). The Omission of Materials Separation Requirements from Air Standards for Municipal Waste Incinerators: EPA's Commitment to Recycling Up in Flames. *Harvard Environmental Law Review*.

MEDIA ENERGY AND ENVIRONMENTAL SOURCE

- As a former PUC and DEP Commissioner with substantial regulatory and sector expertise, Mr. Littell is a frequent source of media expertise on energy, climate, and environmental matters
- For example, https://www.pressherald.com/2021/04/17/mills-has-chance-to-fill-key-energy-post-as-lepage-appointees-puc-term-ends/?utm_source=Press+Herald+Newsletters&utm_campaign=b2a53d7fb6-PPH_Daily_Headlines_Email&utm_medium=email&utm_term=0_b674c9be4b-b2a53d7fb6-199774569&mc_cid=b2a53d7fb6&mc_eid=59ab4e9f7b

PROFESSIONAL AFFILIATIONS

- NEG/ECP, Co-Chairman, New England Governors/Eastern Canadian Premiers Committee on the Environment, 2006-2007
- Chairman, New England Governors Committee on the Environment, 2006-2007
- RGGI, Chairman, vice chair (2x) and treasurer, Regional Greenhouse Gas Initiative, 2008-2015
- NARUC, Vice chair, National Association of Regulatory Utility Commissioners' Task Force on Environmental Regulation and Generation, 2012-2015
- NRRI, Board of Directors, National Regulatory Research Institute, 2012-2015
- The Climate Registry (TCR), Executive Board, Carbon Registry, 2010-2015
- MANE-VU, Chairman, Mid-Atlantic/Northeast Visibility Union, 2006-2010, which developed the Northeast and Mid-Atlantic States' Regional Haze compliance plan under the Clean Air Act

COMMUNITY INVOLVEMENT

- Maine Audubon, Board Chair, Executive Committee, Strategic Planning Committee, 2014-present
- Portland Trails, former Board President and vice president, board member, 1996-2005, Current Advisory Board Member
- Maine Lake Stewardship Program, Advisory Board Member, 2015-2018
- Lovell Land Trust, Trail Steward
- The Climate Registry, former Executive Committee and board member

- St. Ansgar Lutheran Church, former council member, congregation member

SELECTED HONORS AND AWARDS

- Distinguished Policy Scholar, University of Maine, Orono (2010), recognized for work as Maine's environmental commissioner on habitat protections, the Regional Greenhouse Gas Initiative, product stewardship, and consumer toxics protections
- Leadership Maine (2009-2010), Rho class
- Public Service for the Environment Award by the Sierra Club, Maine Chapter, (2015), for work on the Regional Greenhouse Gas Initiative and as environmental commissioner
- Environmental Achievement by Maine Audubon (2007), for implementation of significant wildlife habitat protections for vernal pools, wading bird, waterfowl, and shorebird habitats, which protected approximately two million acres of these habitats