Guidehouse

New Hampshire Locational Value of Distributed Generation Study

Final Report

Prepared for:

New Hampshire Public Utilities Commission

Submitted by:

Guidehouse Inc.
77 South Bedford Street | Suite 400 | Burlington, MA 01803

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Table of Contents

Section Page

Executive Summary iii

1.0 Introduction 1
1.1 Regulatory Context 2
1.2 Study Scope and Analysis Parameters 4
1.3 Analysis Timeframe 6
1.4 Electric Distribution Companies 7
1.5 Distributed Generation Technologies 8
1.6 Study Approach and Report Structure 10

2.0 Location Identification (Step 1) 10
2.1 Screening Analysis 11
2.2 Load Forecasts 12
2.2.1 Overview of Analysis of Factors on Peak Load Forecasts 13
2.2.2 Base Case Load Forecast 14
2.2.3 High Case Load Forecast 15
2.2.4 Low Case Load Forecast 17
2.2.5 Load Forecasts by EDC 18
2.3 Capacity Deficiency Screening by Location 20
2.3.1 Location Selection Criteria 25
2.3.2 Locations Selected for In-Depth Analysis 26
2.3.3 Distribution Capacity Deficiency Forecasts for Selected Locations 27

3.0 Estimation of Investment Costs for Determining Avoidance Values (Step 2) 32
3.1 Investment Costs Associated with Capacity Needs 33
3.1.1 Derivation of Distribution Capacity Costs 33
3.1.2 EDC Locational Capacity Investments 34
3.2 Capital Cost Results by Load Forecast Scenario 36

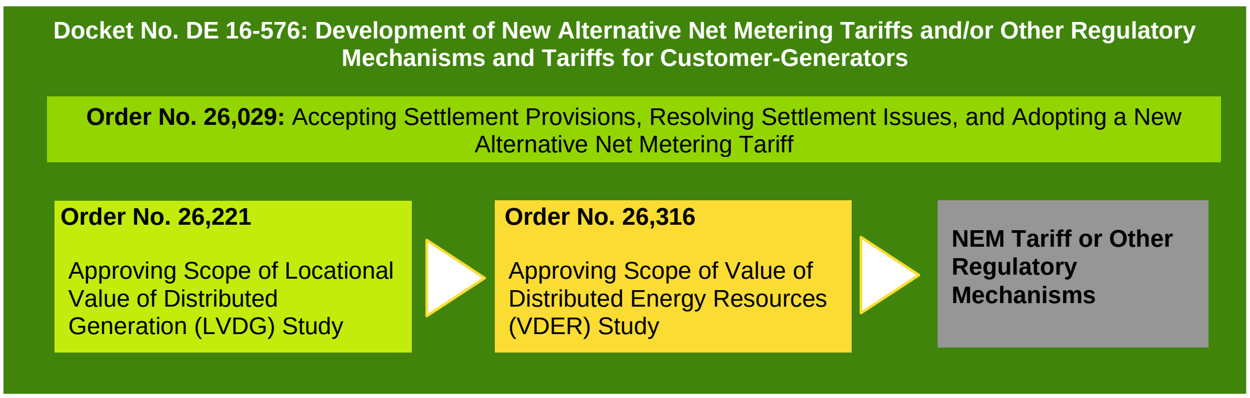
4.0 Economic Analysis and Mapping of DG Output Profiles with Distribution Capacity Needs (Step 3) 38
4.1 Annual Avoidance Benefits Estimation Methodology 38
4.1.1 RECC Methodology Detailed Summary 39
4.1.2 Annual Avoidance Value Results 42
4.2 Hourly Avoidance Value Estimation Methodology 49
4.2.1 Examples of Analytical Approach to Calculate Hourly Value 49
4.2.2 Hourly Avoided Cost Analysis Summary and Results 56
4.3 Mapping of DG Production Profiles with Distribution Capacity Need 59
4.3.1 Load and DG Production Profiles 60
4.3.2 Mapping of DG Production Profile with Capacity Deficiency Profile 69
4.3.3 Methodology to Map Capacity Deficiency and DG Production Profiles (Example) 80
4.4 Summary: DG Production Profile Analysis 81

5.0 Conclusions 81

Appendix A. Detailed Methodology and Assumptions A-1
A.1 Analysis of Economic Variables Impact on Load A-1
A.2 Forward-Looking Violation Screening A-3
Appendix B. Forward-Looking Capacity Deficiencies by Location B-1
Appendix C. Selection of Real Economic Carrying Charge C-1
Appendix D. Economic Analysis D-1
D.1 Three Additional Examples of Annual Value for Avoidance of Investment ... D-1
D.2 Hourly Analysis Results for Remaining 11 Sites D-10
Appendix E. Additional Examples of Load and DG Output Profiles E-1
E.1 Three Additional Examples of Locational Load Profiles E-1
E.2 Three Additional Detailed Examples of DG Production Profile Mapping to Load E-3
E.3 DG Production Profiles for Remaining 11 Sites..E-14
Appendix F. Glossary..F-1
F.1 List of Acronyms and Abbreviations F-1
F.2 Glossary of Terms F-2
Appendix G. References.. G-1
G.1 Report Sources G-1
G.2 Real Economic Carrying Charges (RECC) References G-1
Appendix H. List of Figures and Tables... H-1

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

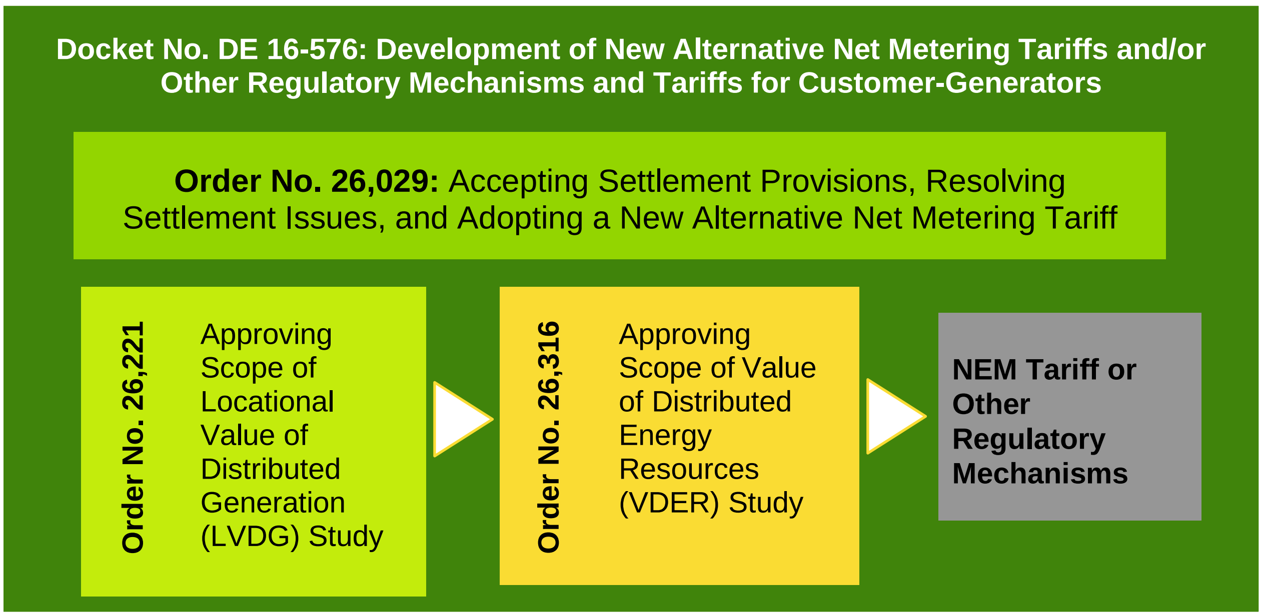
[4] NHPUC Order No. 26,029, Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff, June 23, 2017. Available at: https://www.puc.nh.gov/regulatory/Docketbk/2016/16-576/ORDERS/16-576_2017-06-23_ORDER_26029.PDF (approving the adoption of a 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

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[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

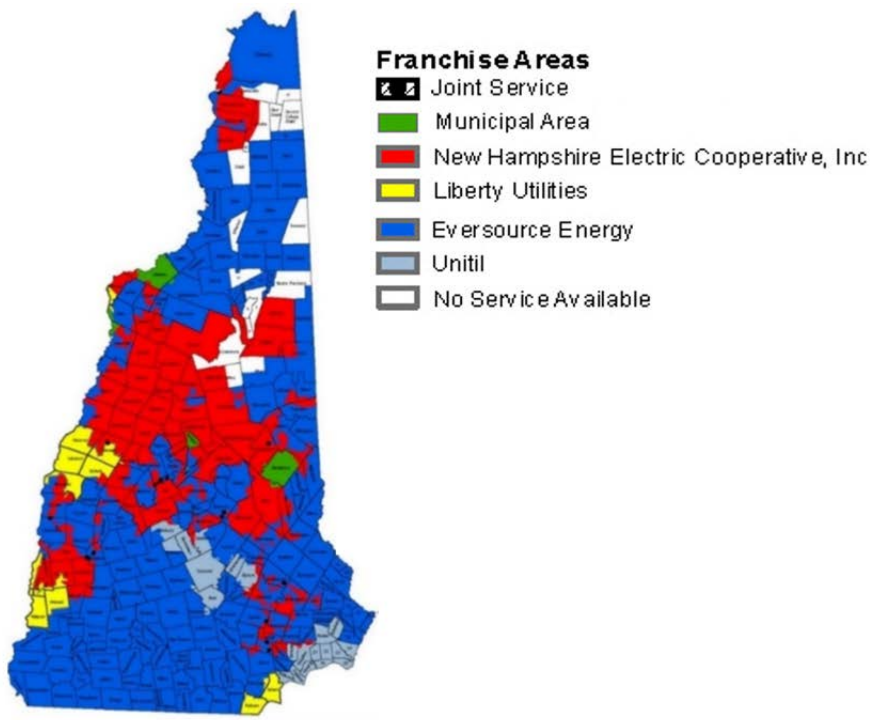
For locational analysis of various EDC distribution system capacity upgrade projects that were examined, two distribution planning assumptions that existed at the time the project was initially proposed or placed into service were applied. First, load forecasts for future projects are based on current 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

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[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.

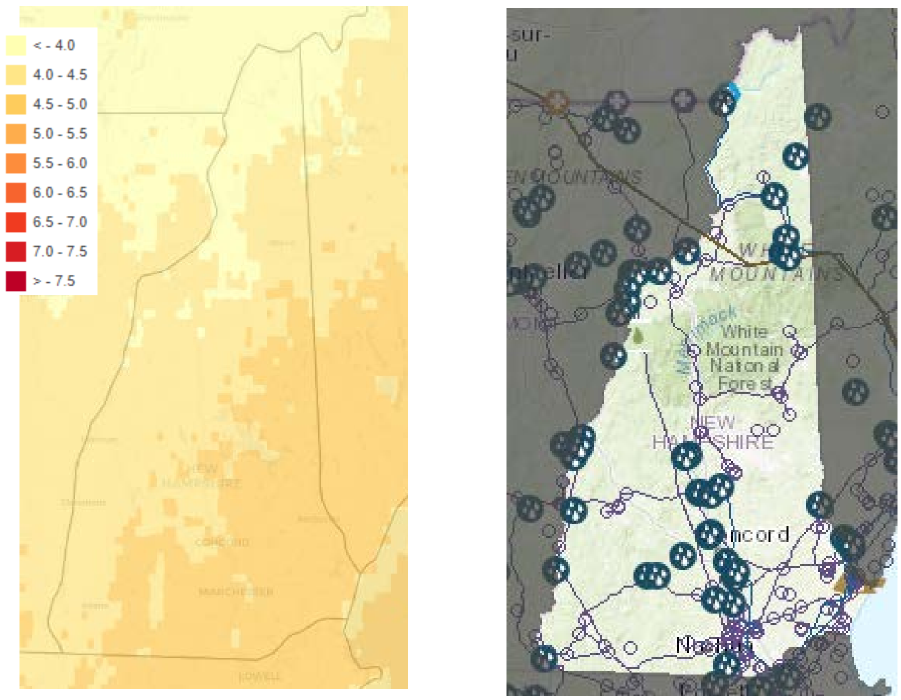
[16] Note: it is understood that solar and other DG developers pay costs associated with installation and interconnection; these costs are not considered in the LVDG study but will be evaluated as relevant to system-wide values in the VDER study.

[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

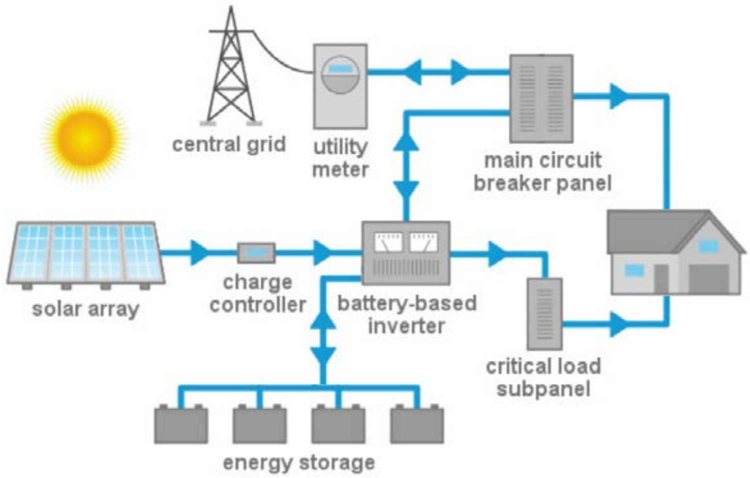
Source: Energy Information Administration (EIA), https://www.eia.gov/state/?sid=NH#tabs-4

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.

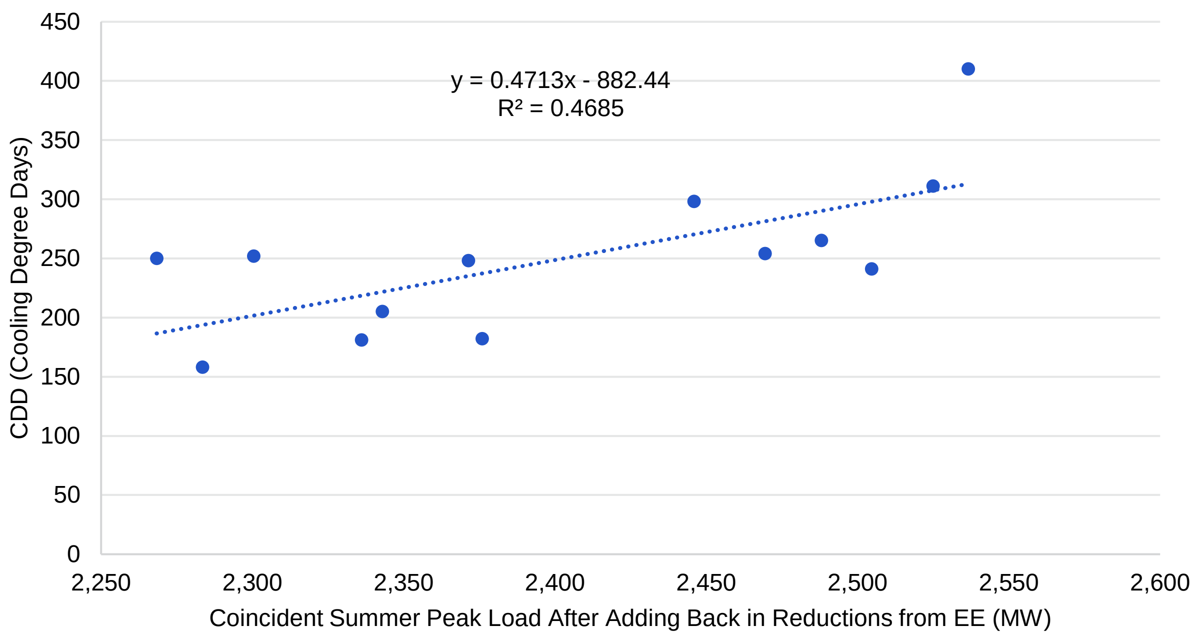
- **Low Case:** The Low Case load forecast was based on the Base Case and considered a lower estimate of electric load growth due to increases in levels of EE and overall increases in energy conservation activities. The Low Case used the "Average" weather load forecasts developed by each EDC and the 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.

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[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.

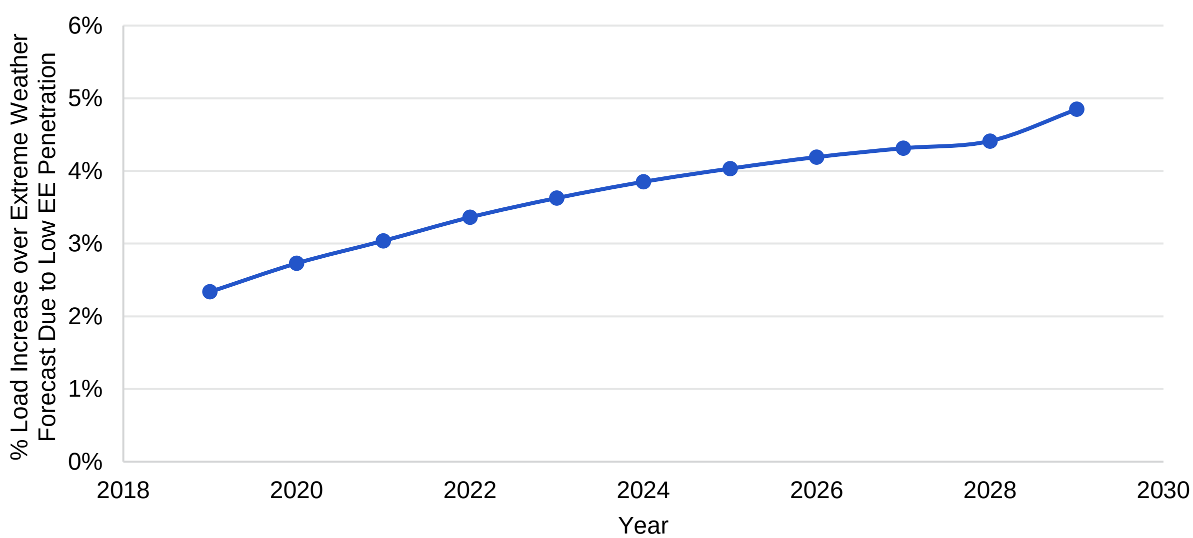
Table 5. Summary of EDC High Load Forecast Methodology

	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.

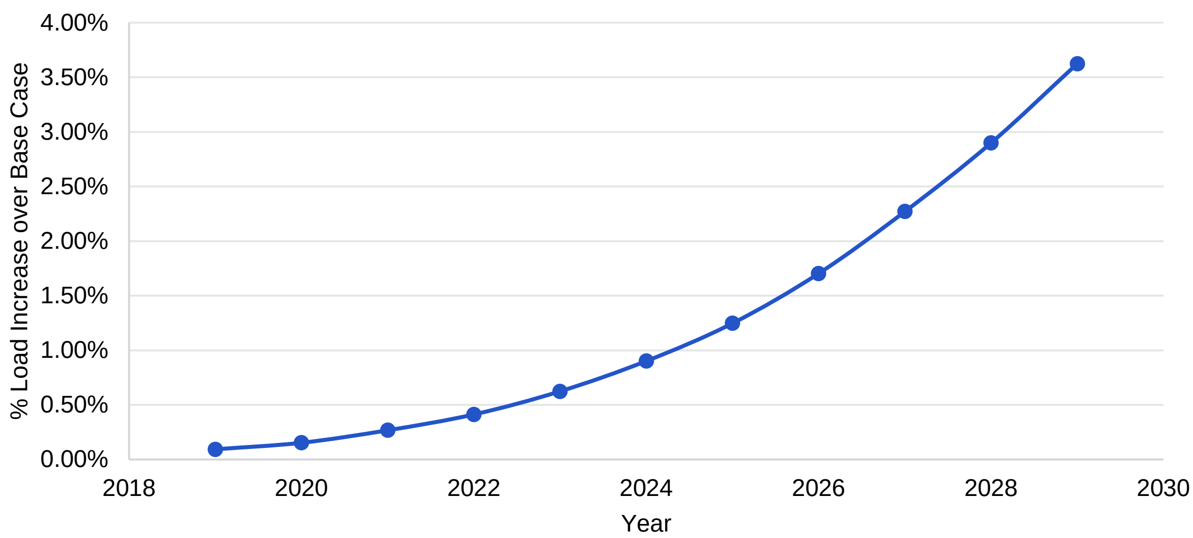
for the High Case analysis, as shown in Table 6 and Figure 8. In this analysis, there is a large decrease in battery price and the continuation of national incentives for EVs.

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

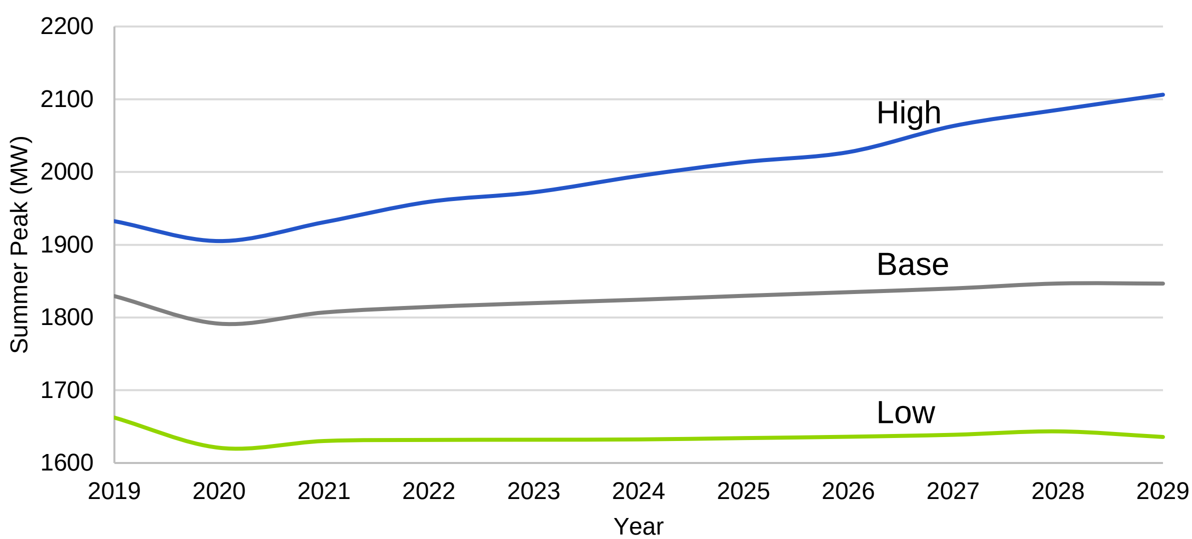
To account for higher than projected EE participation, the average weather forecast for each EDC was decreased by 50% of the forecast of statewide EE peak impacts (Table 4) divided by forecasted total state summer peak load excluding EE and PV impacts.

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.

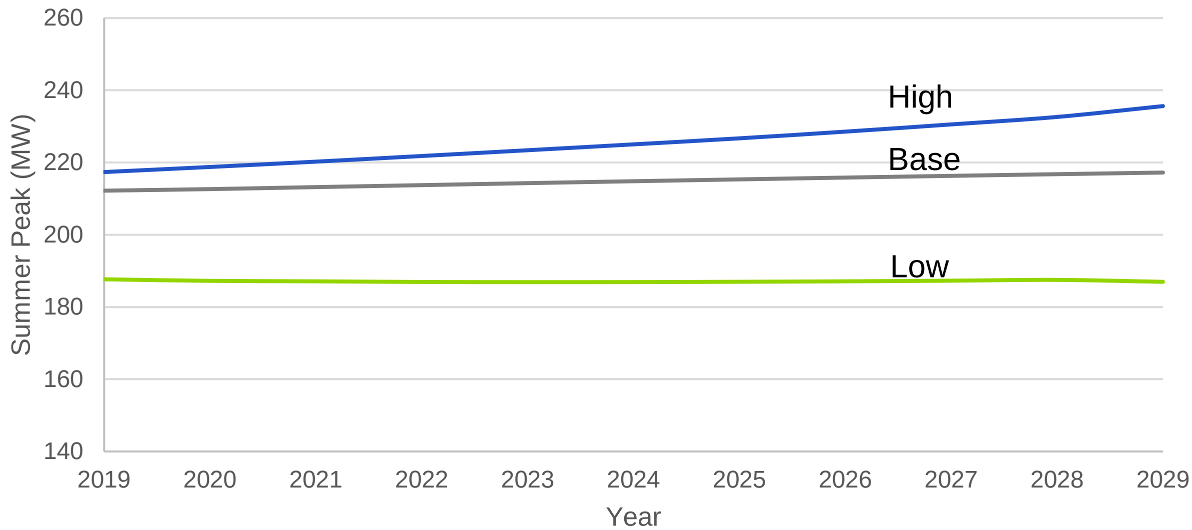
Figure 9. Eversource Load Forecast (Base, Low, High)



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)

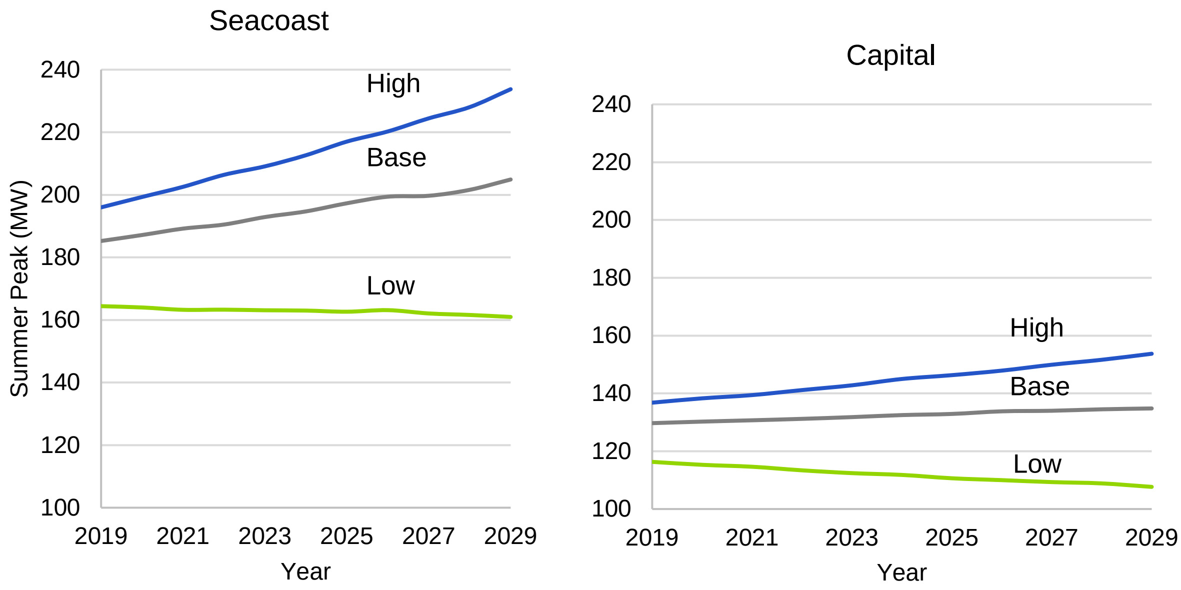


Source: Guidehouse, EDC data

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.

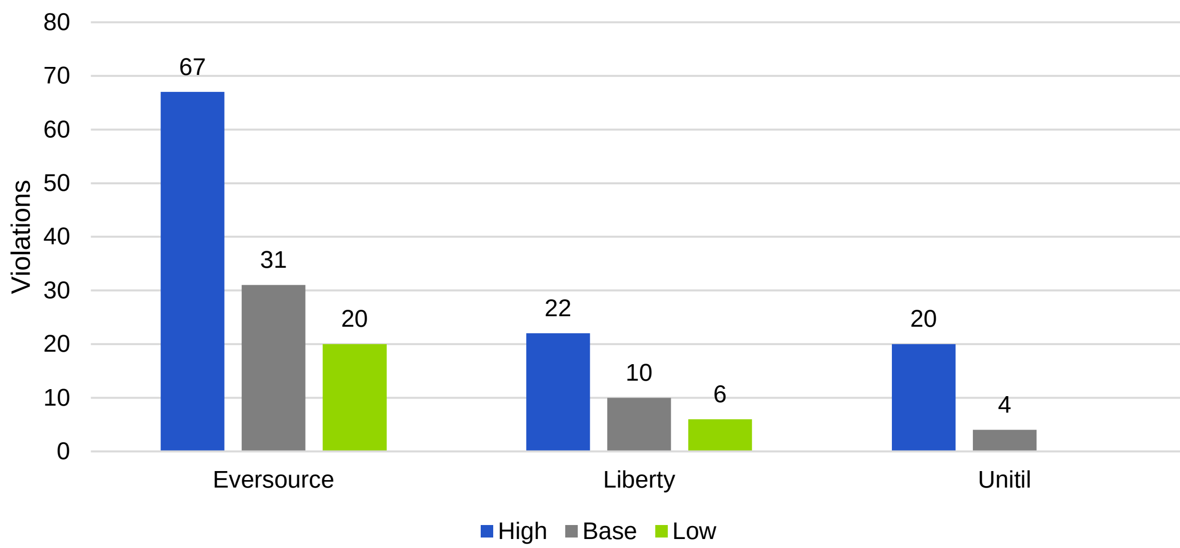
[28] Eversource recently revised its planning criteria and disagreement exists between Eversource, Commission Staff, and the Office of the Consumer Advocate (OCA) regarding the need for those revisions. *See* Order No. 26,362 at 5 (June 3, 2020); *see* also Docket No. DE 19-139, Settlement of the Parties, 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.

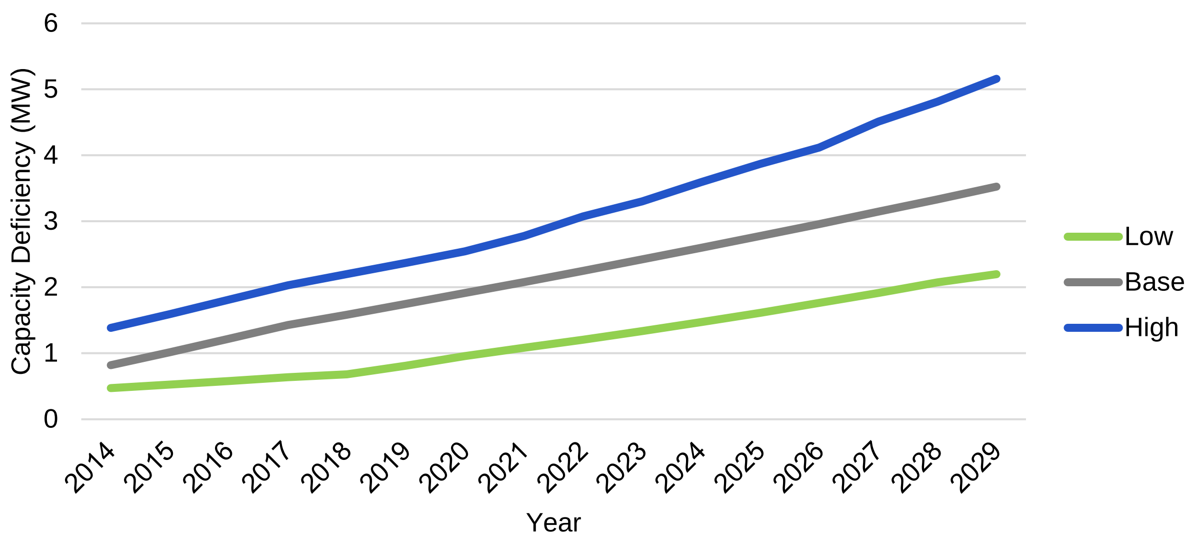
The cost of traditional distribution capacity investments to address deficiencies for each of the 16 locations and the potential value of avoidance via DG is presented in Section 3.0.

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]

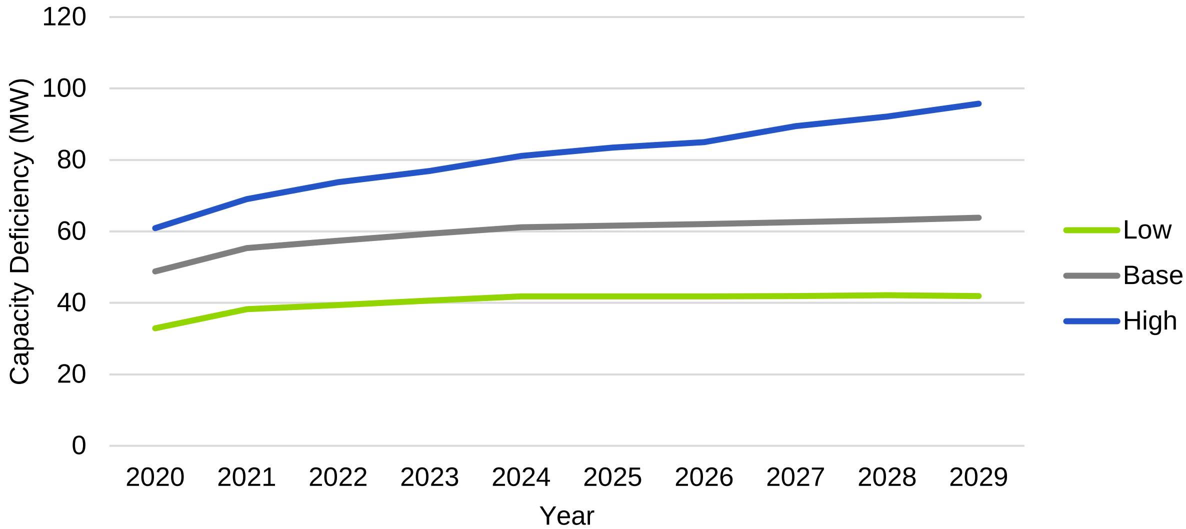


Source: Guidehouse, EDC data

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.

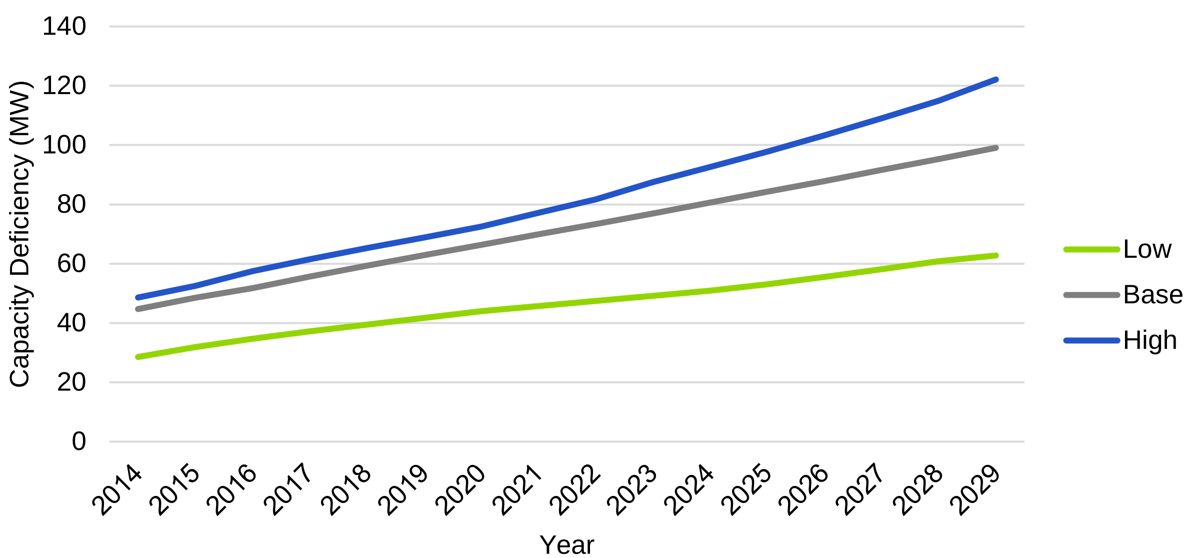
Figure 14. Forward-Looking Location Capacity Deficiencies – Eversource



Source: Guidehouse, EDC data

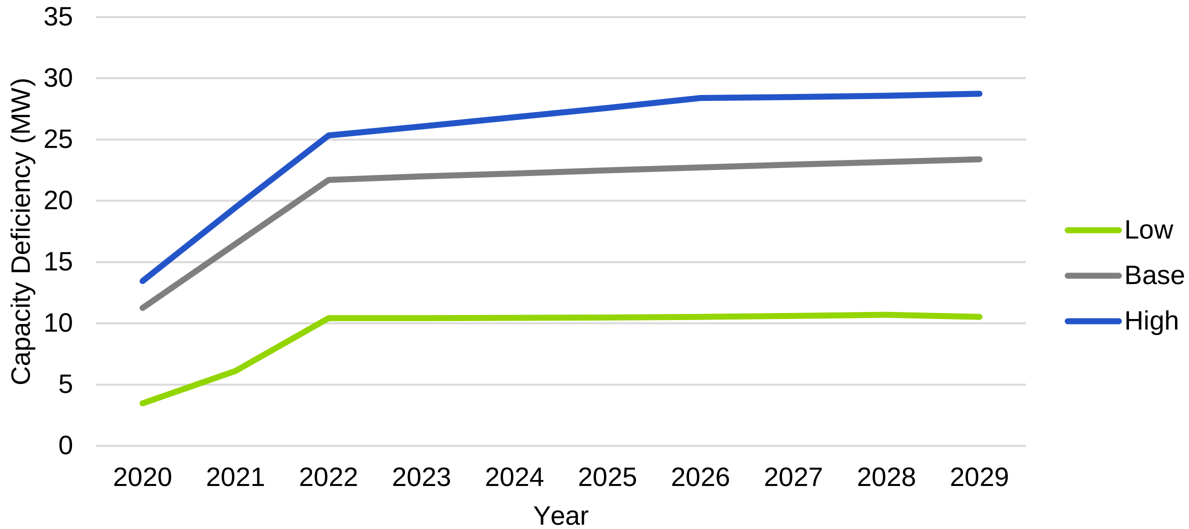
Figure 15 presents capacity deficiencies by year for Liberty. Large capacity deficiencies occur in prior years, as a major project is a previously completed project. Figure 16 presents the forward-looking capacity deficiencies by year for Liberty.

Figure 15. Historical Location Capacity Deficiencies – Liberty



Source: Guidehouse, EDC data

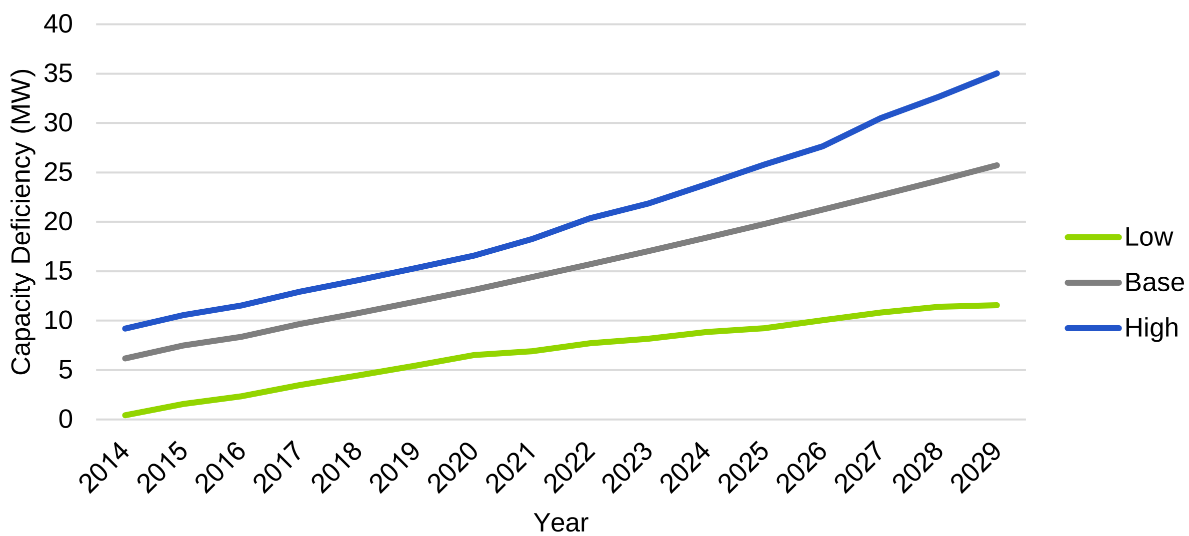
Figure 16. Forward-Looking Location Capacity Deficiencies – Liberty



Source: Guidehouse, EDC Data

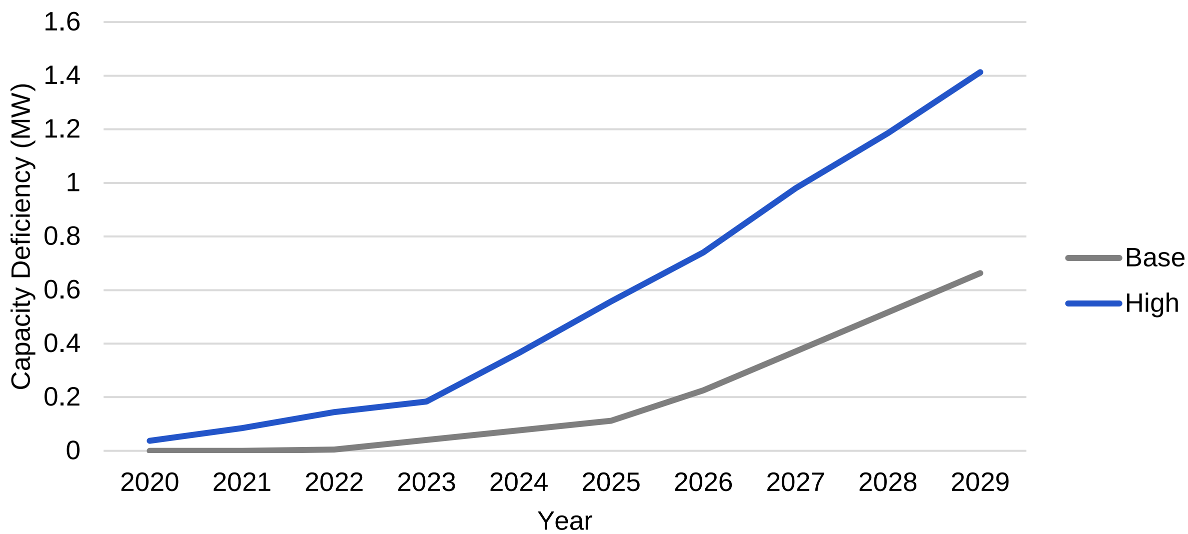
Figure 17 and Figure 18 present historical and forward-looking capacity deficiencies by year for Unitil. As shown in Figure 17, similar to Liberty, a major project completed in prior years caused large capacity deficiencies to occur in early years and increase steadily throughout the study timeframe 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

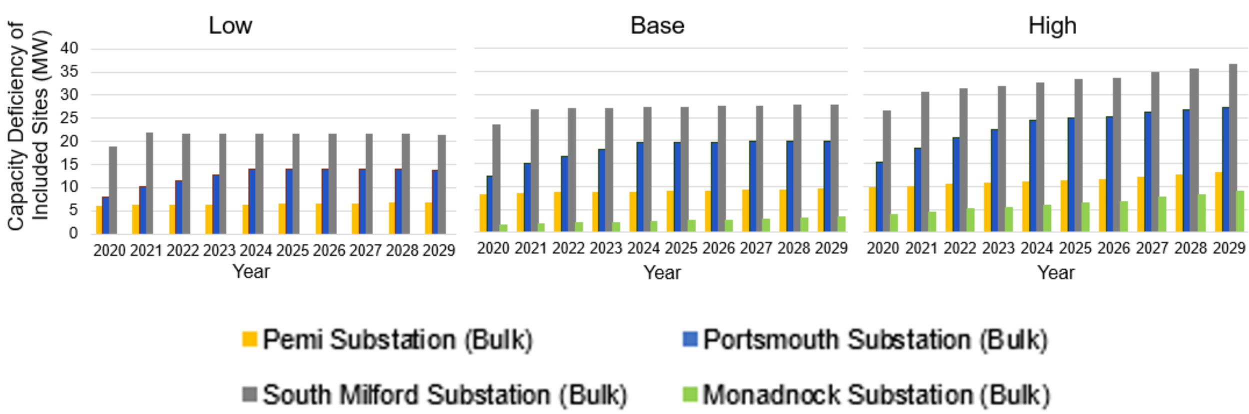
Figure 18. Forward-Looking Location Capacity Deficiencies – Unitil



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.

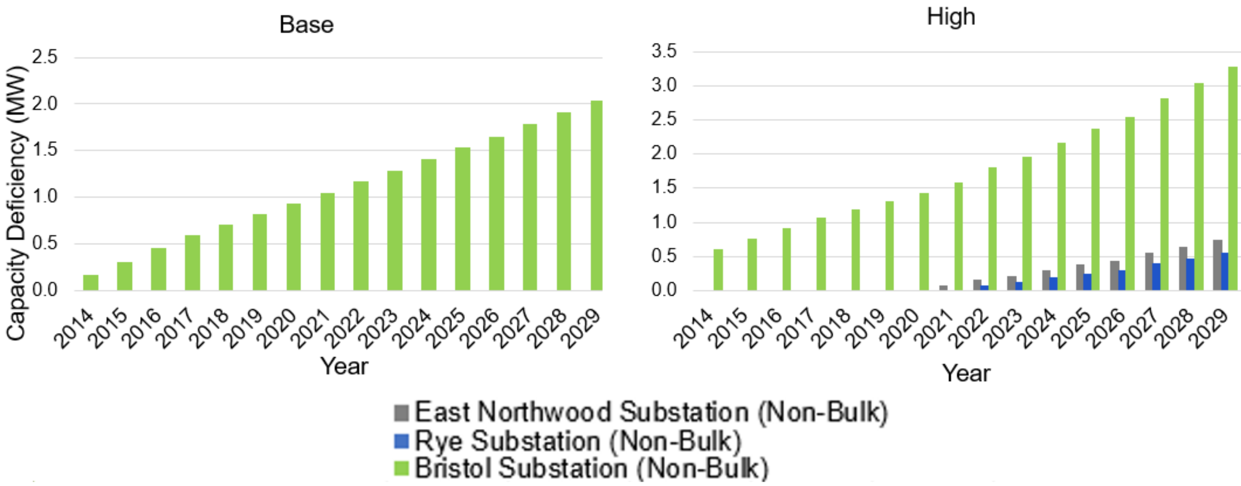
Figure 19. Bulk Substation Capacity Deficiencies – Eversource



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.

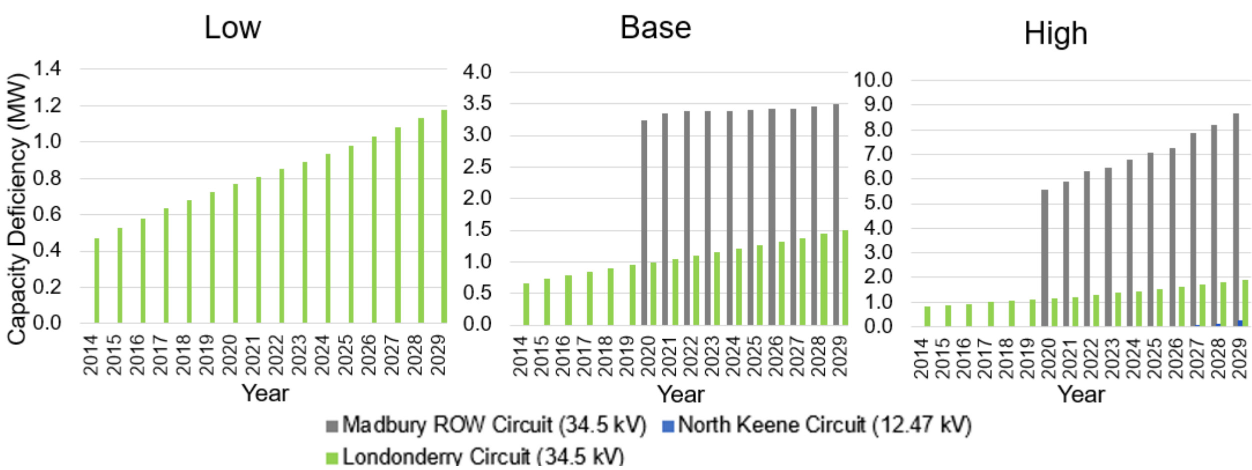
Figure 20. Non-Bulk Substation Capacity Deficiencies – Eversource



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.

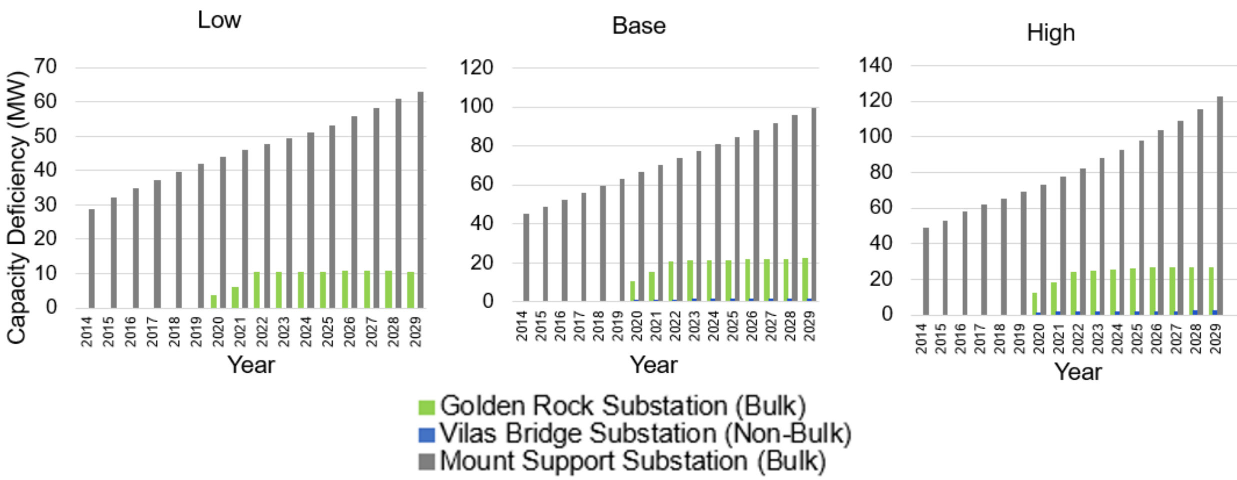
Figure 21. Circuit Capacity Deficiencies – Eversource



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.

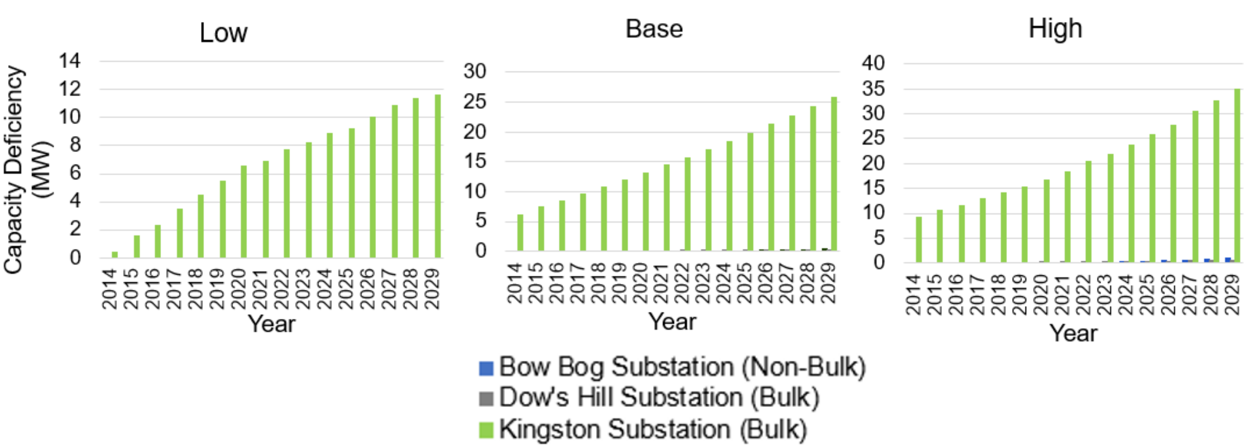
Figure 22. Selected Locations Capacity Deficiencies – Liberty



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

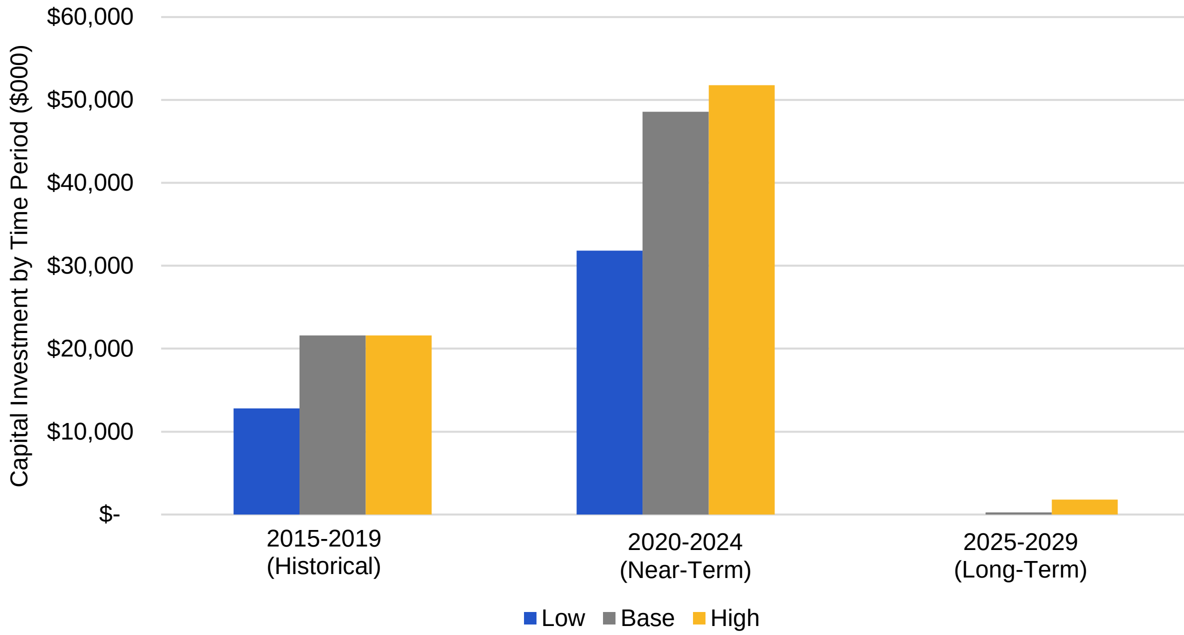
3.1.2 EDC Locational Capacity Investments

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**

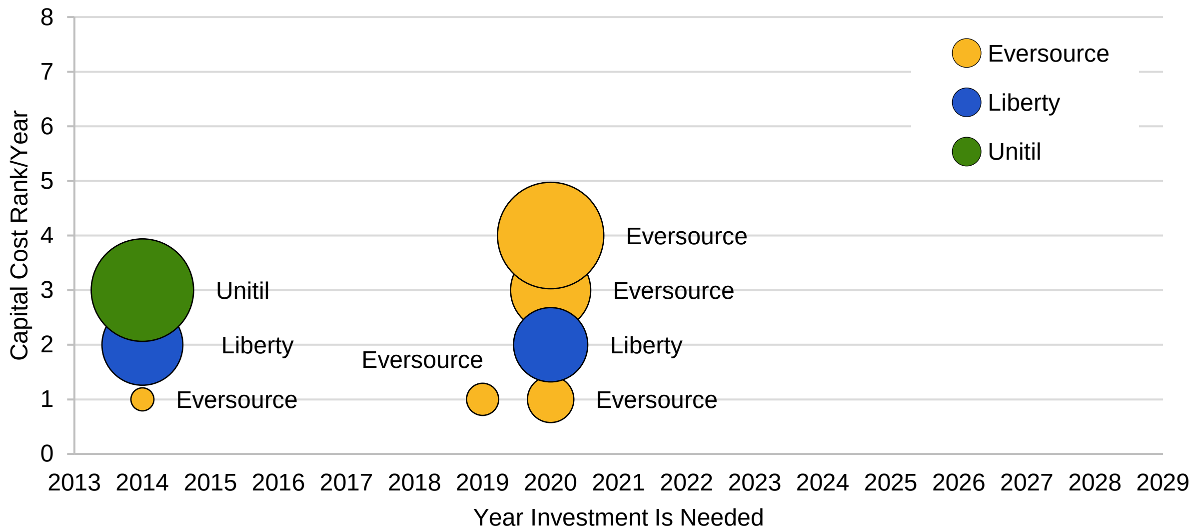
Source: Guidehouse, EDC data

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.

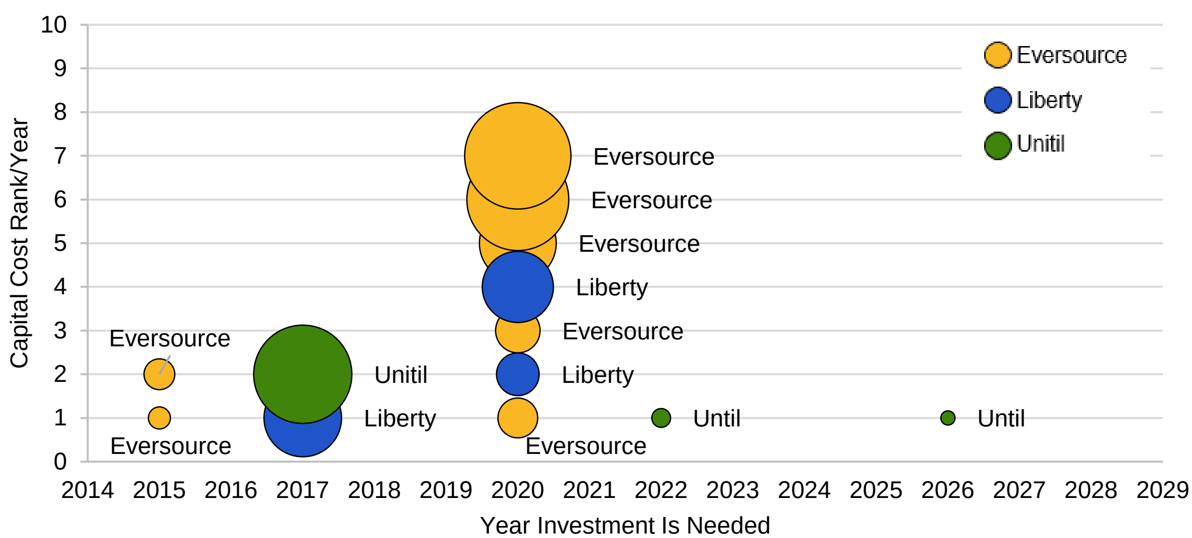
Figure 25. Low Load Forecast Capital Costs by Year of Investment Need



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.

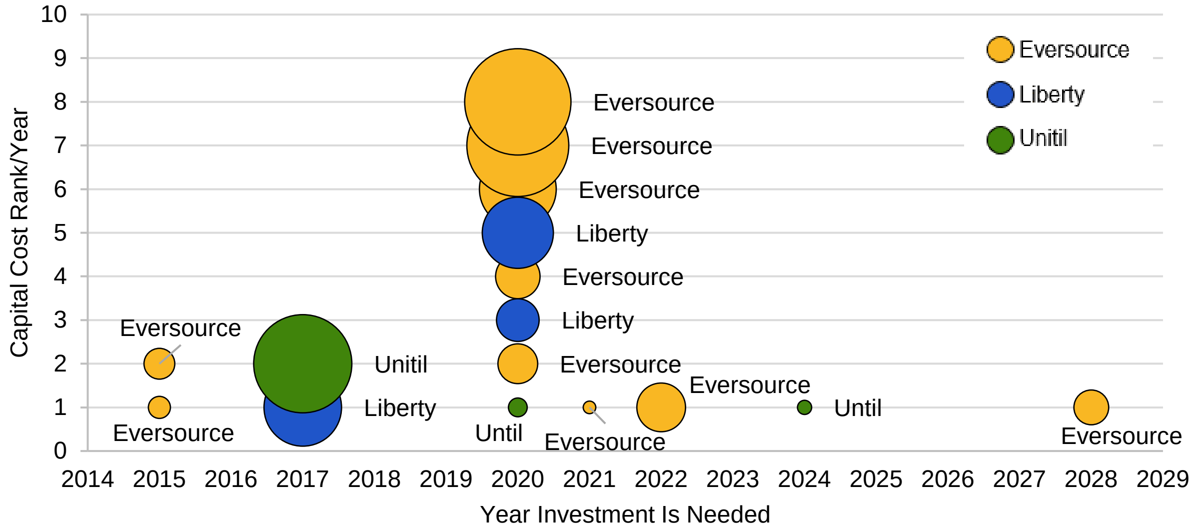
Figure 26. Base Load Forecast Capital Costs by Year of Investment Need



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.

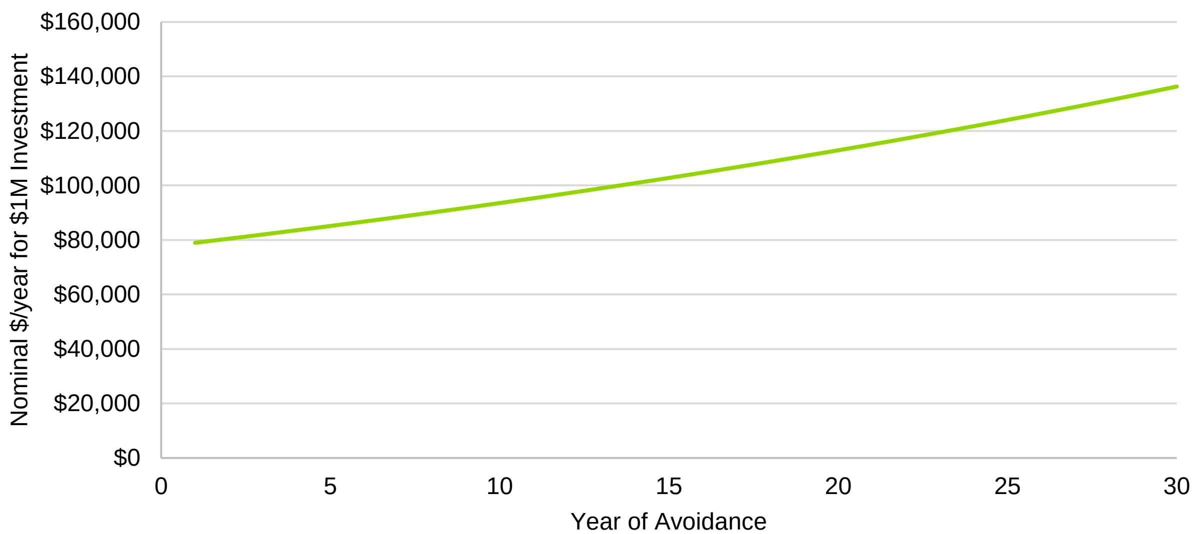
$$Single\ year\ avoidance\ benefit\ (\$) = Revenue\ Requirement * \frac{RECC}{(1 + inflation\ rate)}$$

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

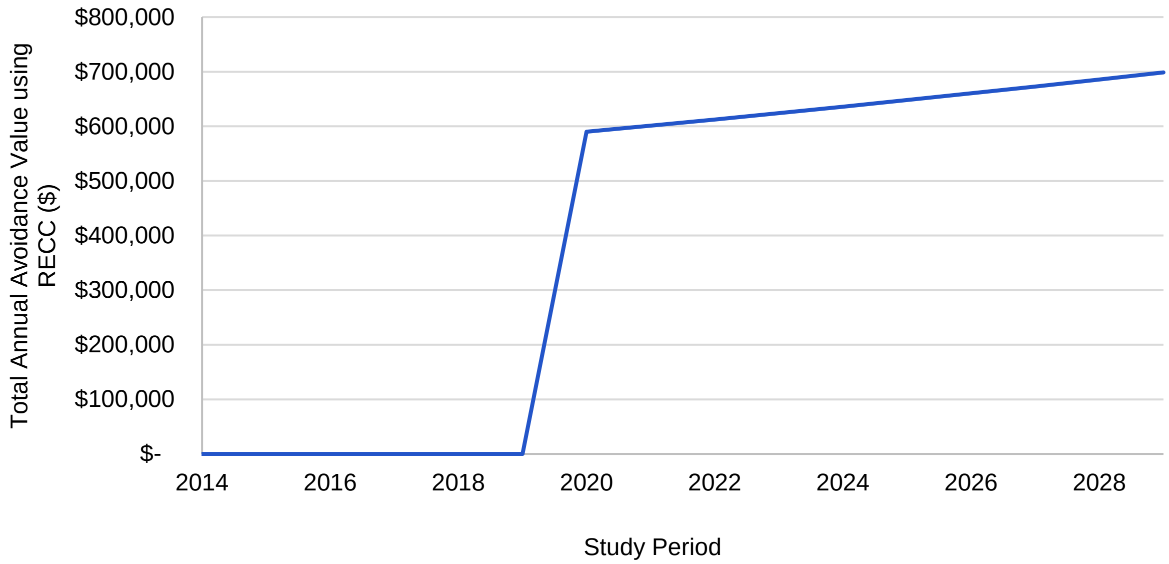
The calculation of the annual economic value from the revenue requirement is shown in detail for two example locations: Pemi Substation in the Eversource service territory and Dow's Hill Substation in the Unitil service territory. The results of the annual economic analysis for all locations are presented 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

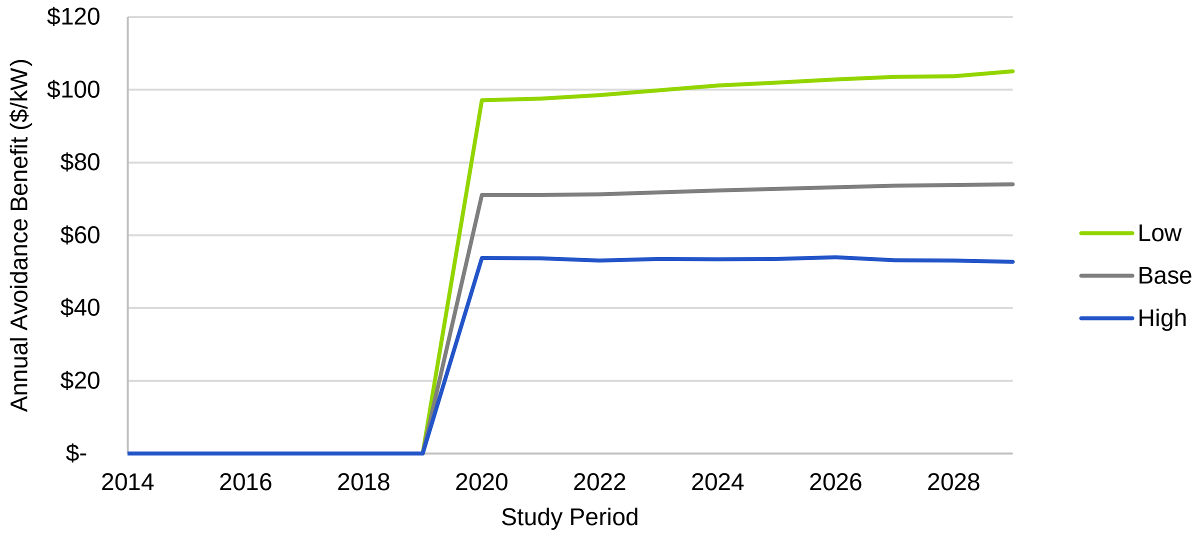
Table 16. Pemi Substation (Bulk) Yearly Economic Analysis- Example Calculations

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)

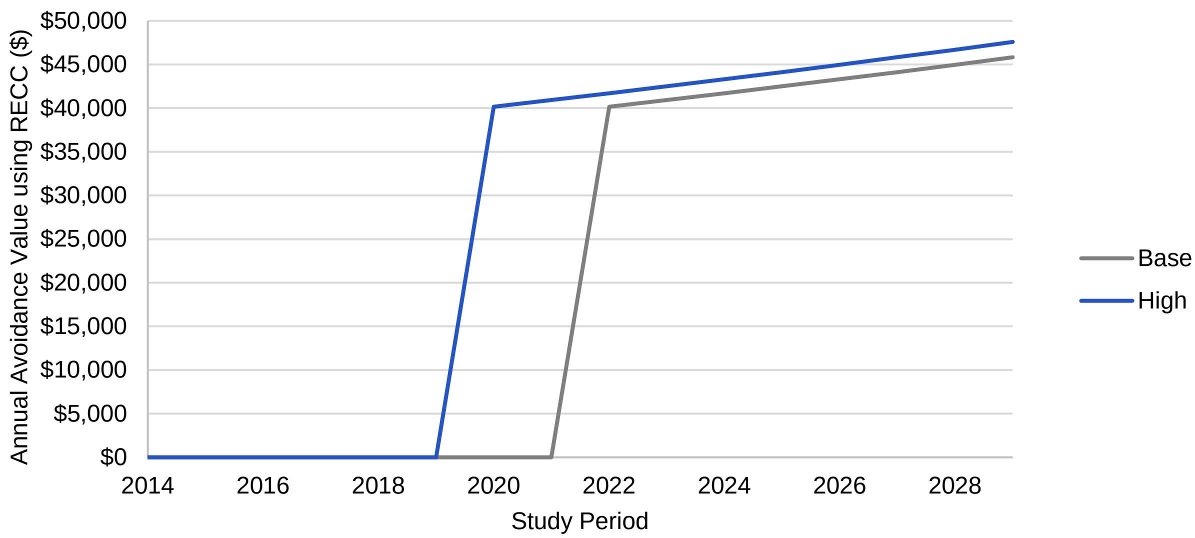


Source: Guidehouse, EDC data

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)

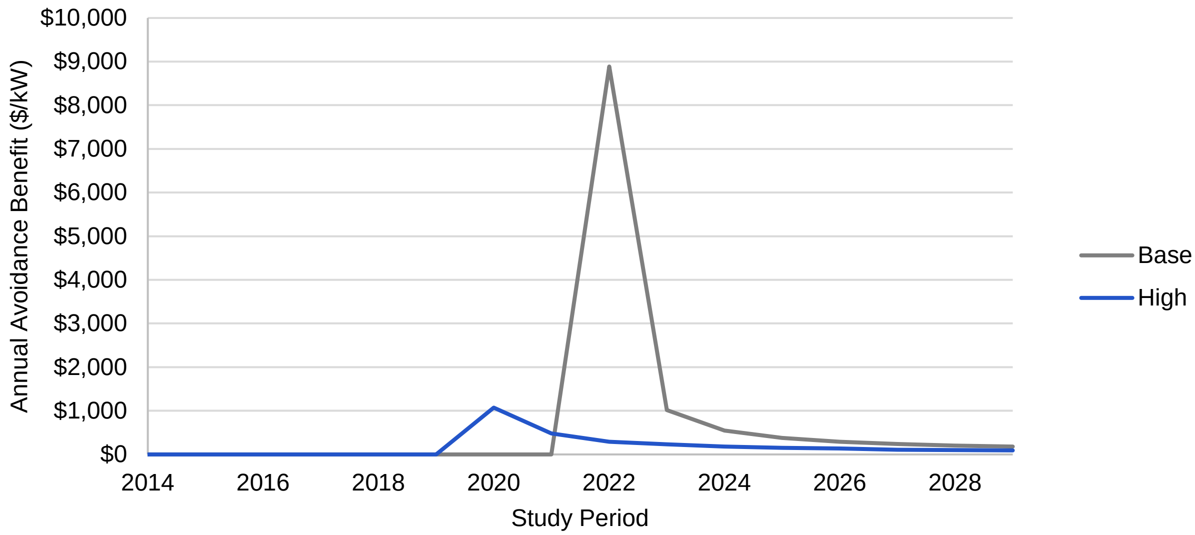


Source: Guidehouse, EDC data

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)

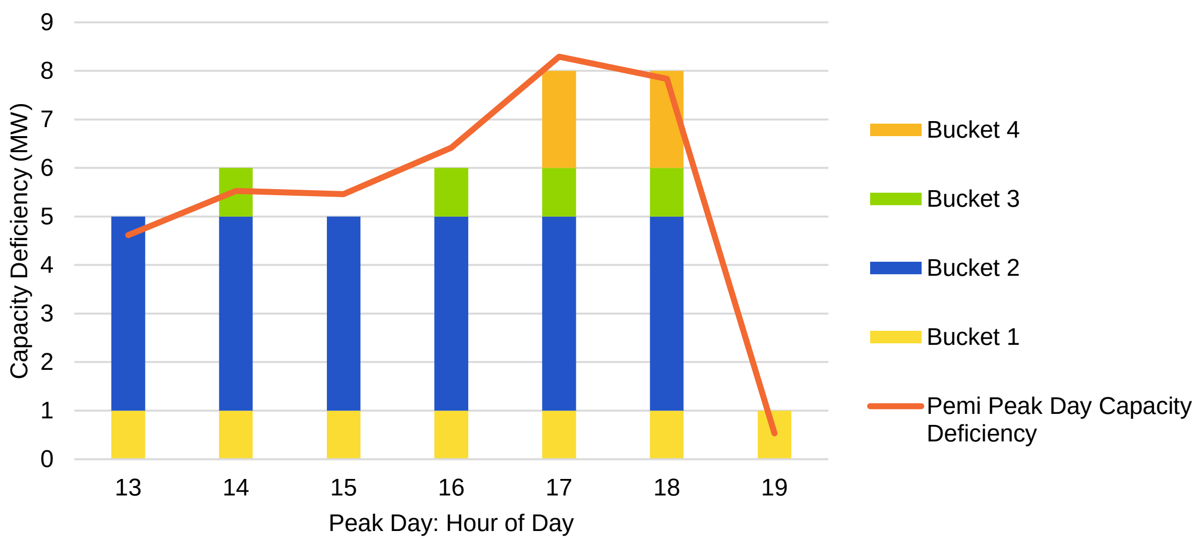
To simplify the explanation of the analytical process, the results that follow are for the peak day for the Pemi Substation. A three-step methodology was developed to assign an avoidance value to each hour. The first step is outlined as follows:

- **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)

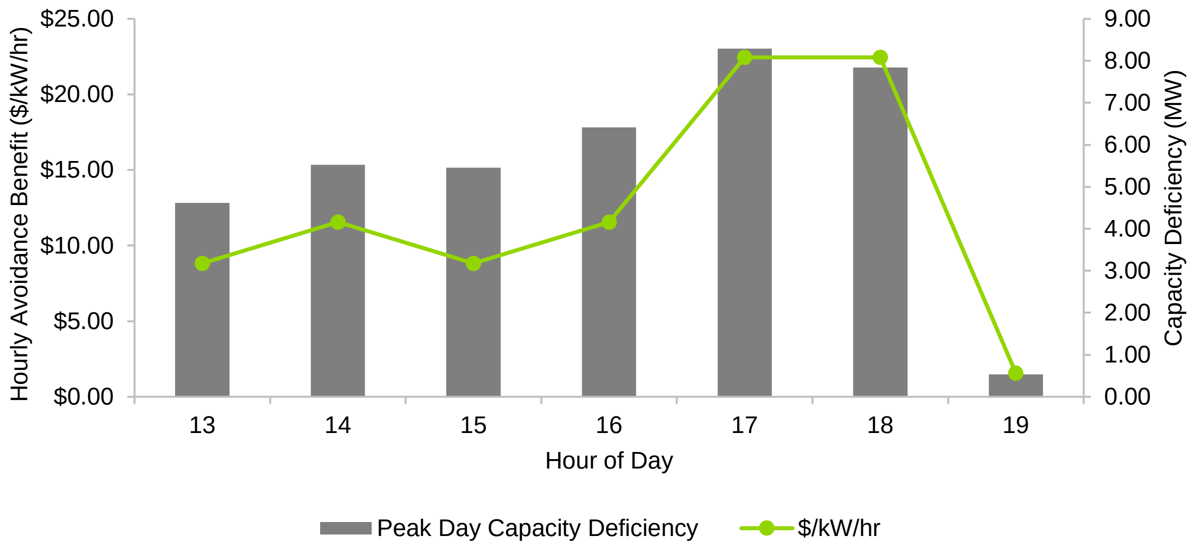
Relative Weight by Hour of Day ↓	Bucket 1	Bucket 2	Bucket 3	Bucket 4	Total Relative Weight
17	14%	17%	25%	50%	26%
18	14%	17%	25%	50%	26%
19	14%	0%	0%	0%	2%
Weight Across Buckets	13%	50%	13%	25%	100%

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.

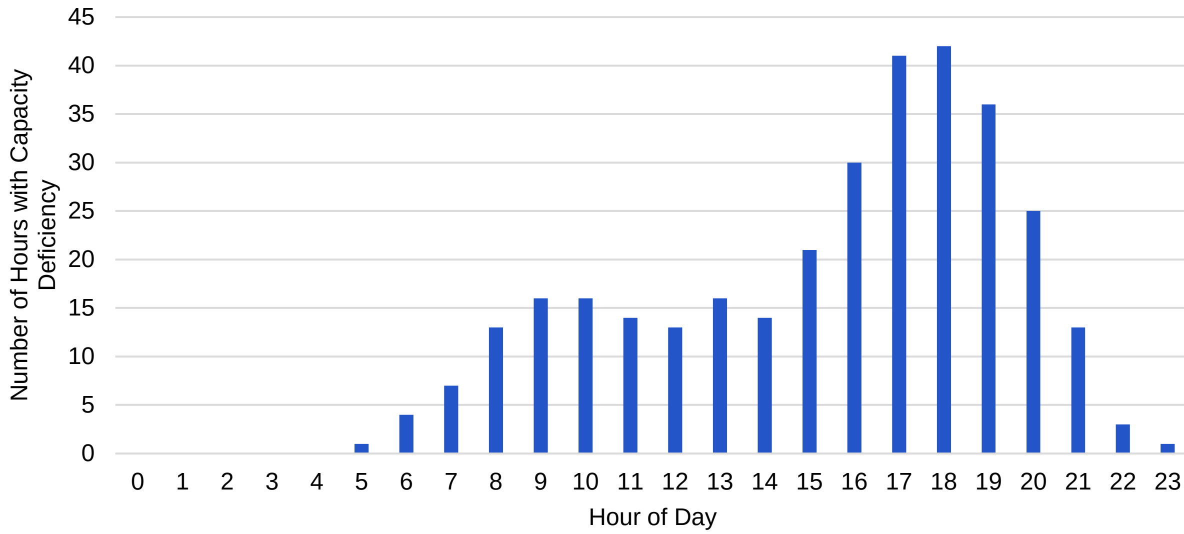
Figure 34. Hourly Avoidance Value and Capacity Deficiency – Pemi Substation (Bulk)



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.

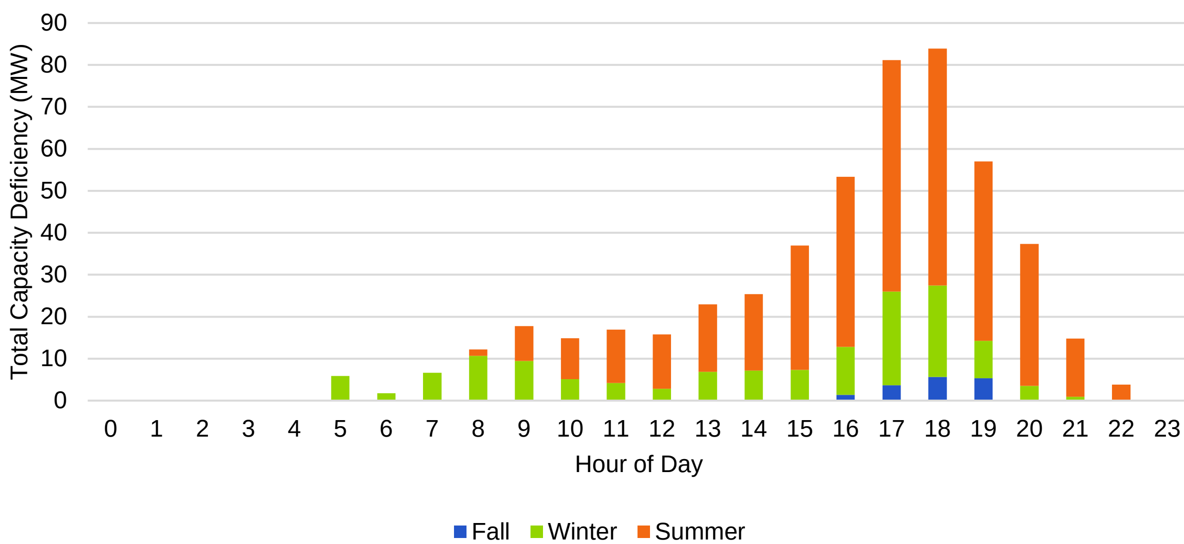
Figure 35. Number of Hours with Capacity Deficiency – Pemi Substation (Bulk)



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.

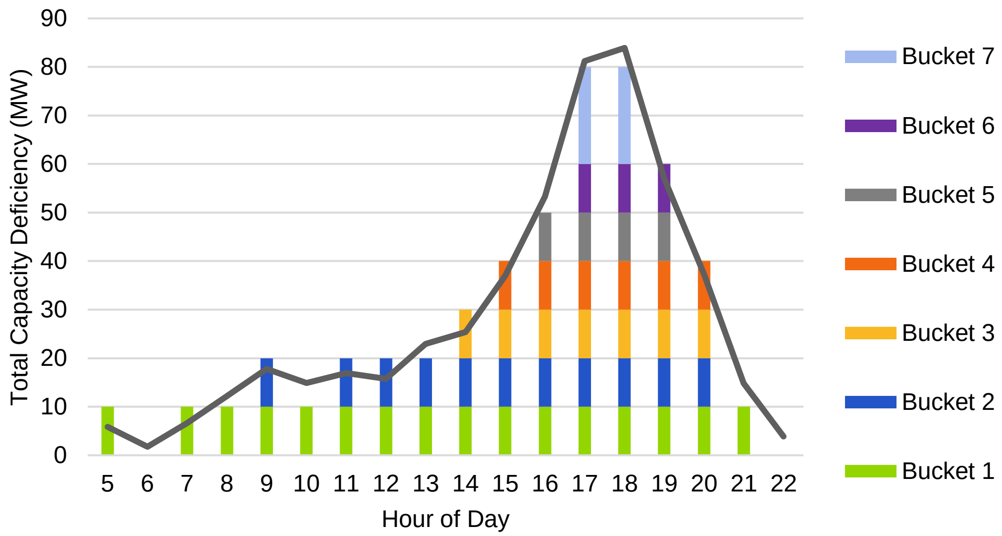
Figure 36. Seasonal Deficit Analysis – Pemi Substation (Bulk)



Source: Guidehouse, EDC data

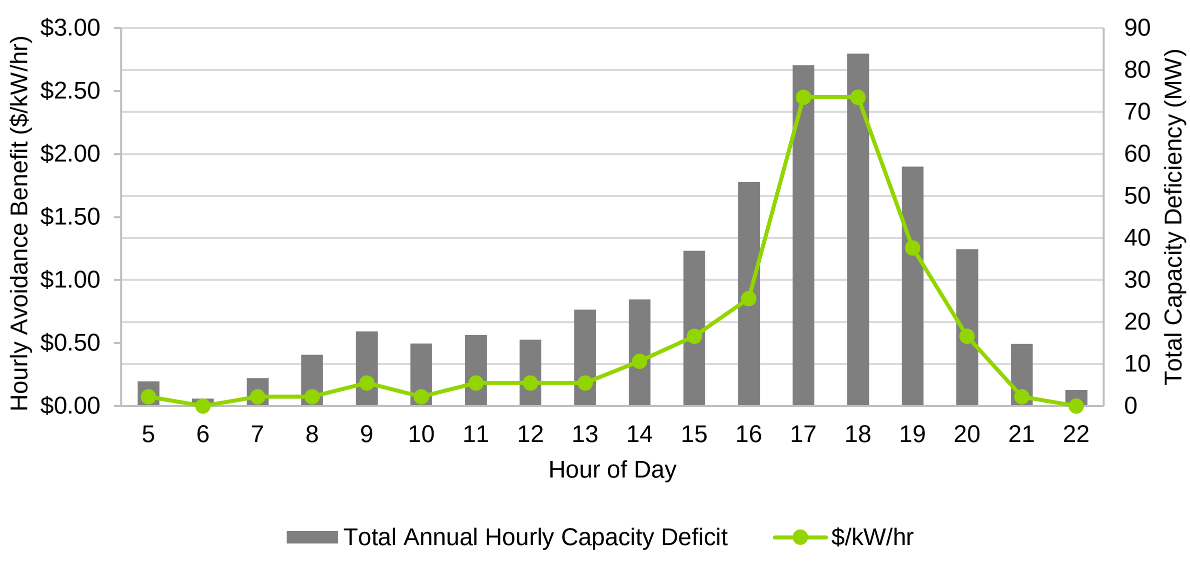
The same three step methodology used for the Pemi peak day can be used to assign a value given the total capacity deficit per hour over a whole year. Figure 37 shows the seven buckets needed to generalize the annual capacity deficit curve. Figure 38 shows the total annual capacity deficit and the $/kW/hr 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

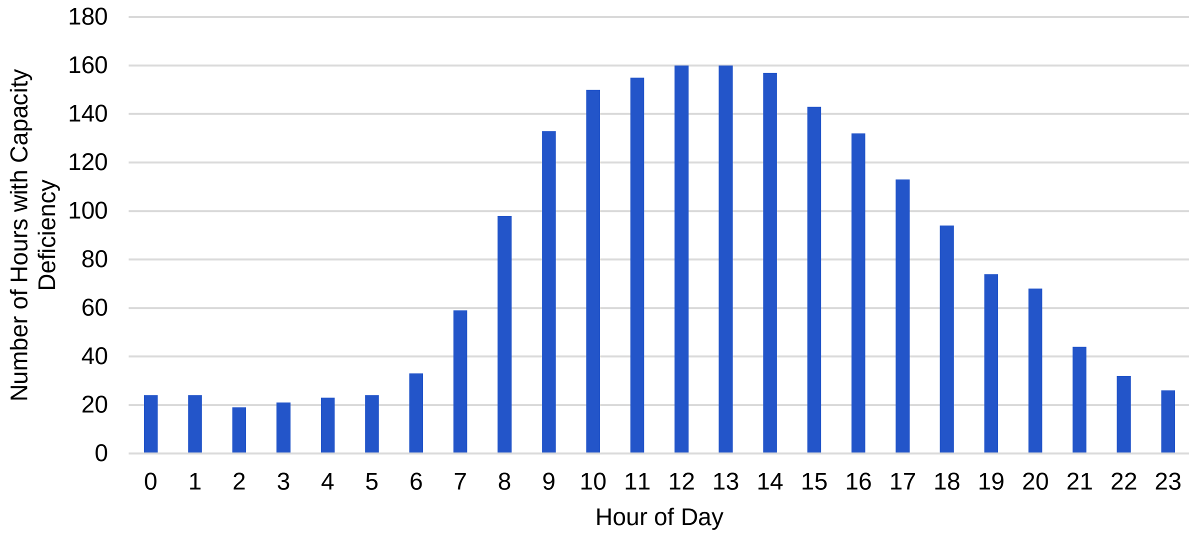


Source: Guidehouse, EDC data

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.

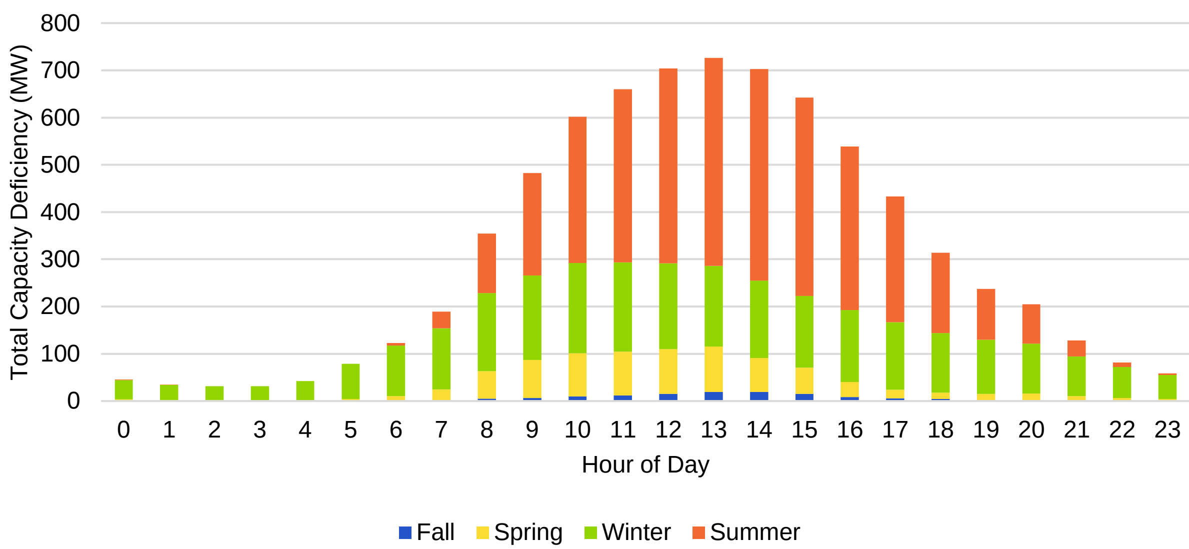
Figure 39. Number of Hours with Capacity Deficiency – Portsmouth Substation (Bulk)



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).

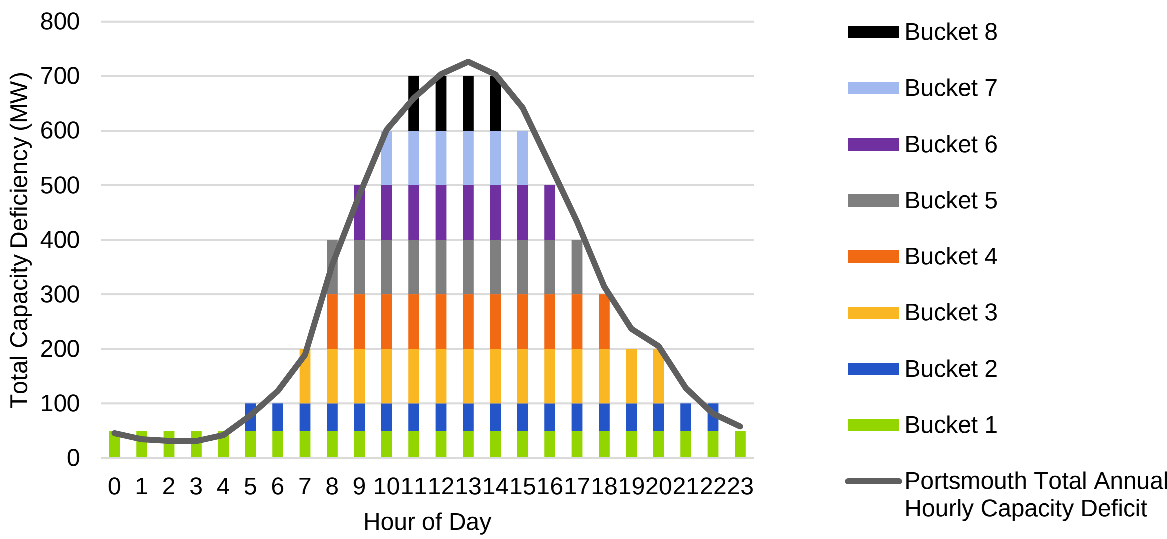
Figure 40. Seasonal Deficit Analysis – Portsmouth Substation (Bulk)



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).

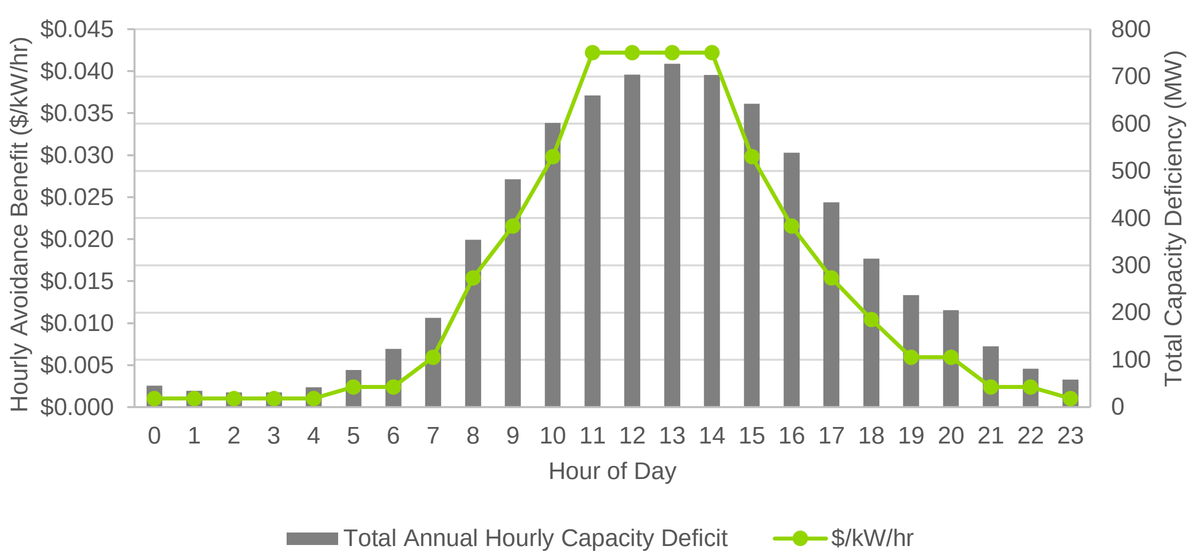
Figure 41. Marginal Load Buckets (MW) – Portsmouth Substation (Bulk)



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
	North Keene Circuit (12.47 kV)	Max Deficiency per Hour (MW)												0.11												
		Sum of Deficiency per Hour for One Year (MW)												0.11												
		Count of Hours with Deficiency for One Year												1												
		Hourly Avoidance Value ($/kW/hr)												$ 1,128												
	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
		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
		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
		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	
		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	
		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	
		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	
	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
		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
		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
		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	
	Golden Rock Substation (Bulk)	Max Deficiency per Hour (MW)											2	5	7	8	9	10	10	9	7	5	3	2	0	0
		Sum of Deficiency per Hour for One Year (MW)											3	14	31	56	75	84	65	53	29	13	6	3	0	0
		Count of Hours with Deficiency for One Year											2	6	14	21	24	24	23	19	15	7	4	3	1	1
		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		
	Bow Bog Substation (Non-Bulk)	Max Deficiency per Hour (MW)														0.02	0.07	0.08	0.06	0.04						
		Sum of Deficiency per Hour for One Year (MW)														0.02	0.07	0.08	0.06	0.04						
		Count of Hours with Deficiency for One Year														1	1	1	1	1						
		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						
		Sum of Deficiency per Hour for One Year (MW)																	0.004	0.005						
		Count of Hours with Deficiency for One Year																	1	1						
		Hourly Avoidance Value ($/kW/hr)																	$ 4,483	$ 4,483						
	Kingston Substation (Bulk)	Max Deficiency per Hour (MW)												3	5	8	10	10	11	11	10	9	8	6	3	
		Sum of Deficiency per Hour for One Year (MW)												8	33	57	84	101	107	109	106	84	57	33	10	
		Count of Hours with Deficiency for One Year												6	14	18	21	23	23	24	23	22	15	9	5	
		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.

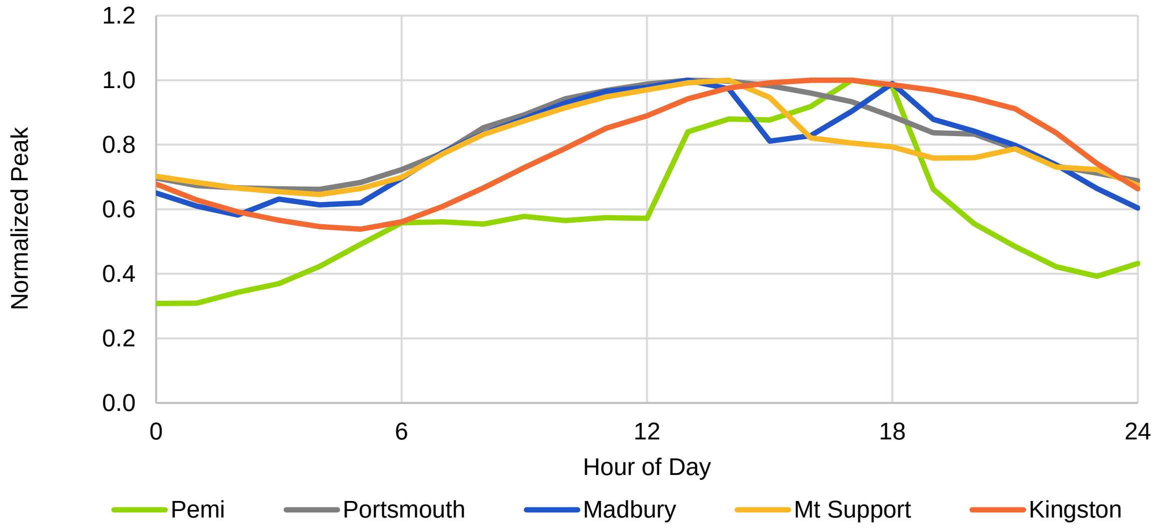
The first step in the study's mapping process includes development of hourly average monthly and peak load profiles for each of the 16 selected locations. Figure 43 presents peak day hourly load profiles for the two locations in this section, and the three additional locations that appear in Appendix 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

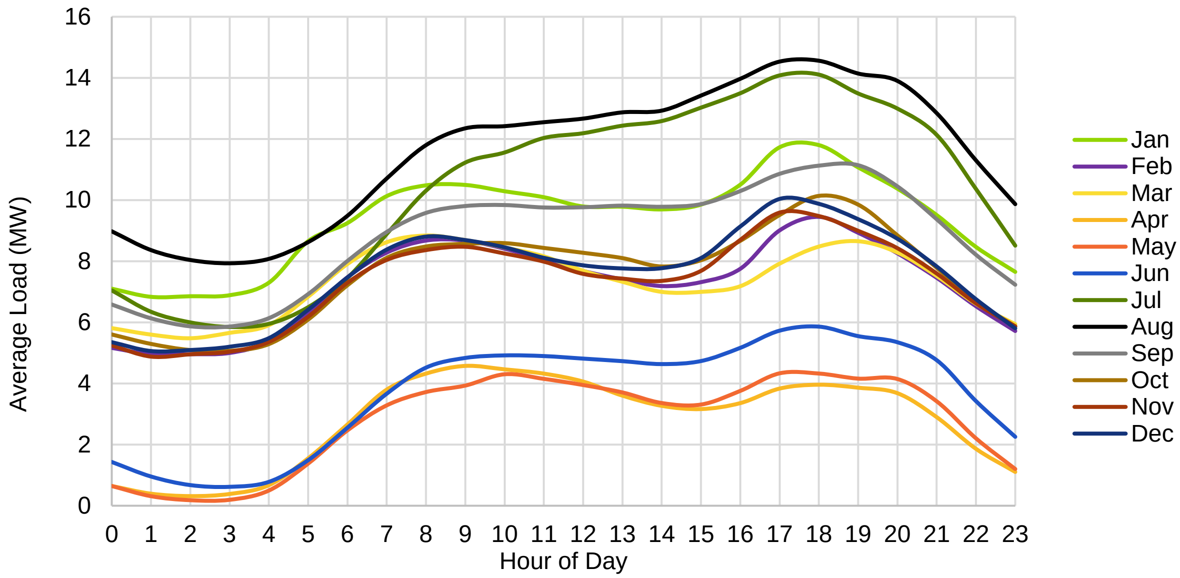
EDC	Location	Region	Winter (Peak and Date Time)	Summer (Peak and Date Time)
Eversource	Pemi Substation (Bulk)	Northern	23 MW 1/7/19 17:00	
Eversource	Portsmouth Substation (Bulk)	Eastern		40 MW 7/30/19 13:00
Eversource	South Milford Substation (Bulk)	Southern	36.9 MW 1/21/19 17:00	41.4 MW 7/30/19 17:00
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:

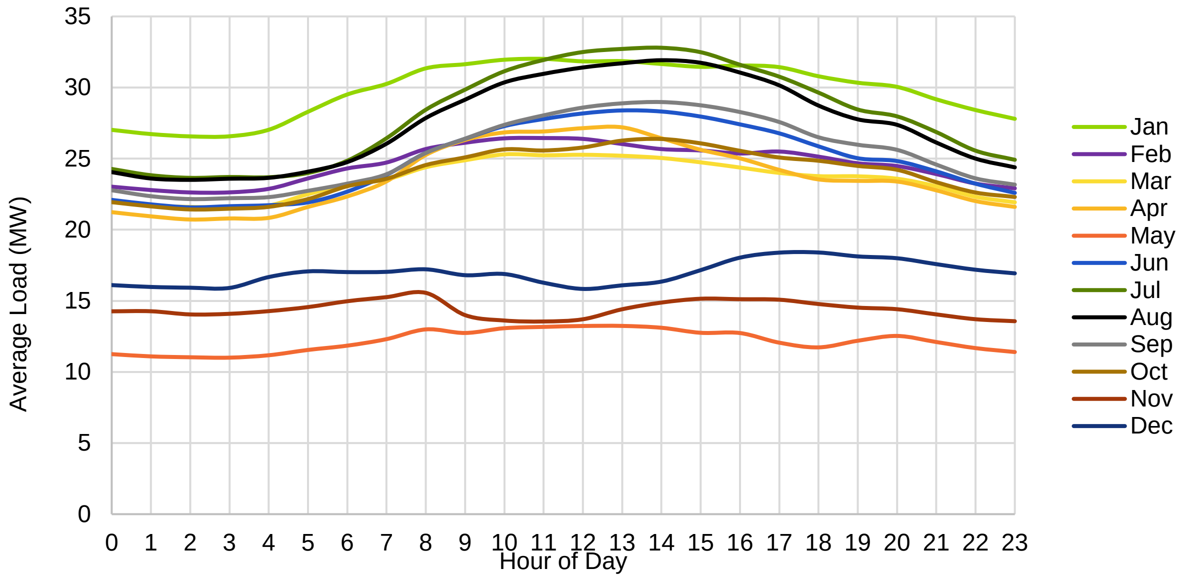
- Pemi Substation (Bulk):
  - Winter peaking with a daily average peak in the early evening
  - Annual Peak Day: 1/7/2019 17:00, 23 MW
- Portsmouth Substation (Bulk)
  - Summer midday peaking substation
  - Annual Peak Day: 7/30/2019 13:00, 40 MW

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

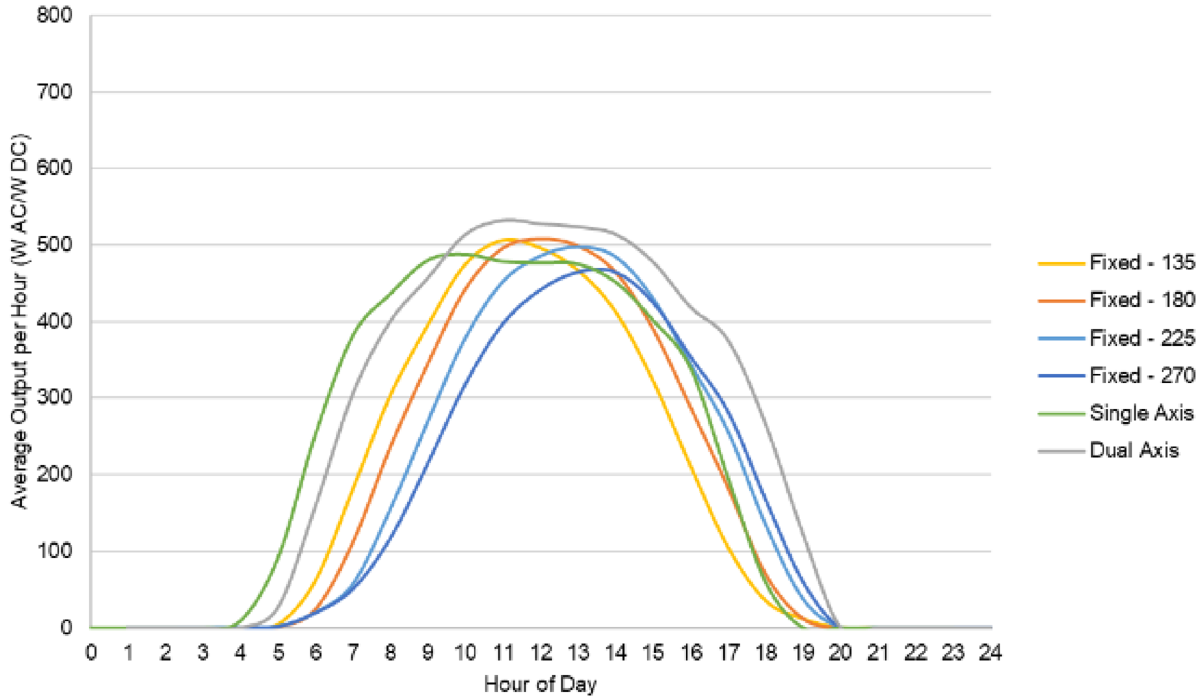
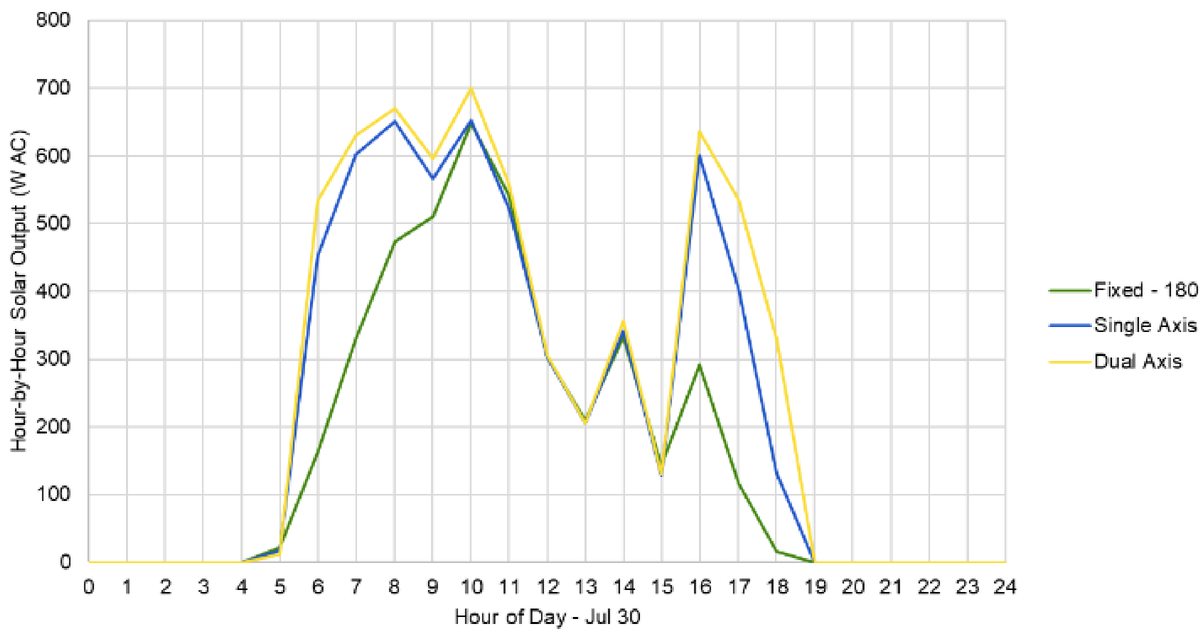


Figure 48. Peak Day Summer Production by Solar Array Configuration Type



Source: Guidehouse

Figure 49. Average Winter Production by Solar Array Configuration Type

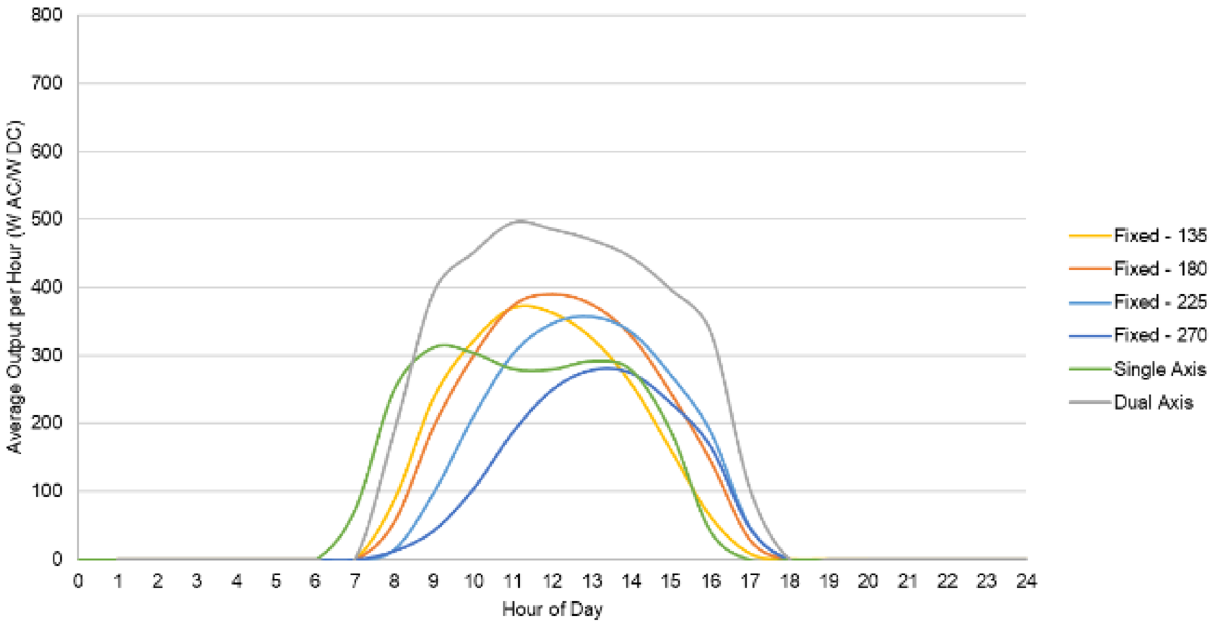
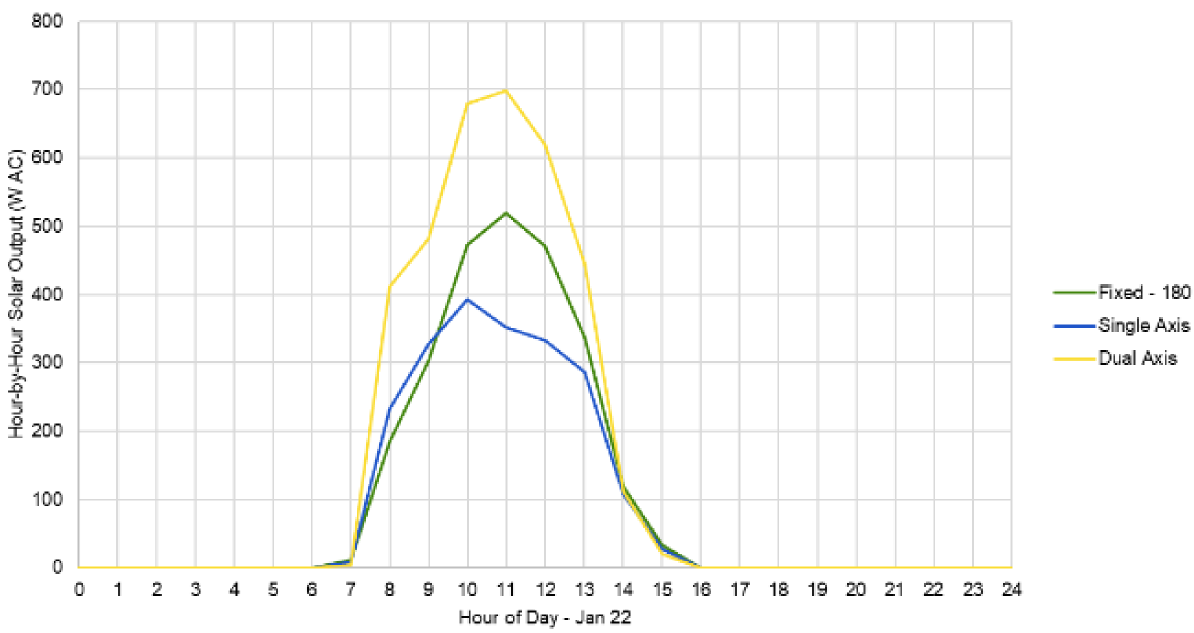


Figure 50. Peak Day Winter Production by Solar Array Configuration Type



Source: Guidehouse

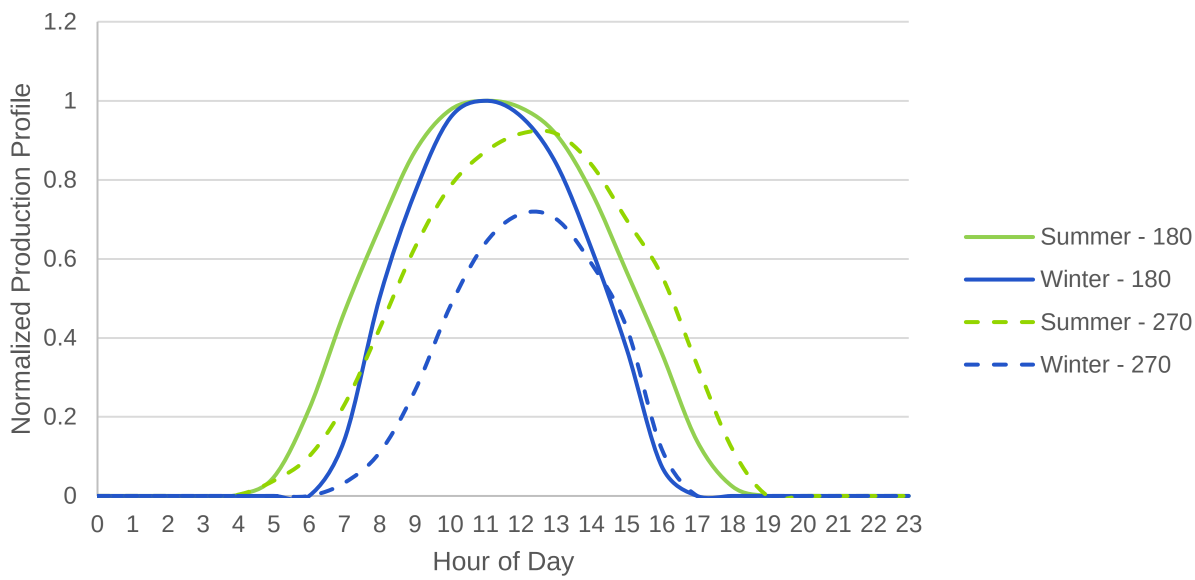
Selection of Representative Solar PV Production Profile

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

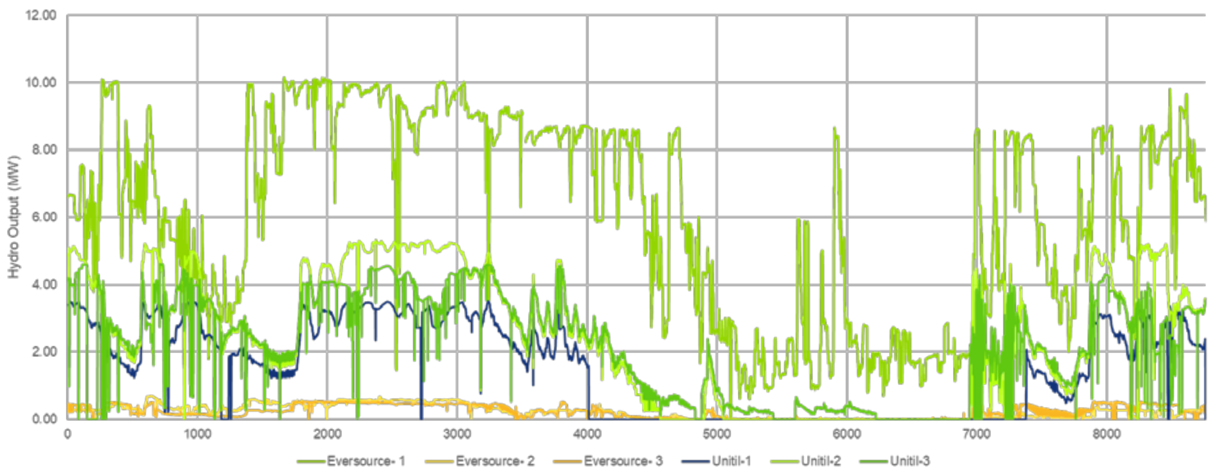


Note: Normalized to max for each season for the Fixed-180° case.
Source: Guidehouse

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



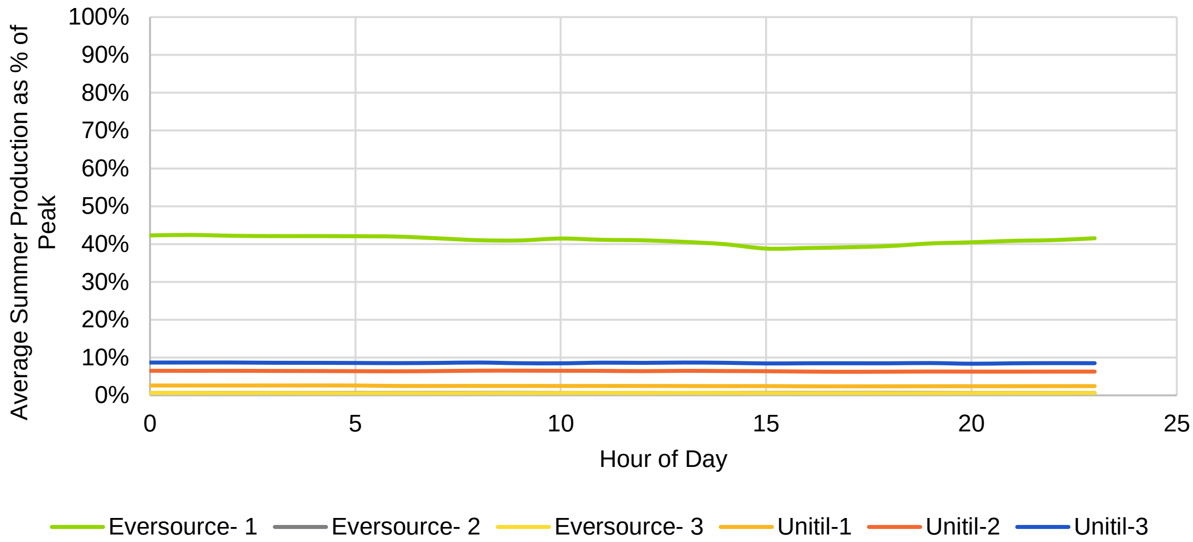
Source: Guidehouse, EDC data

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.

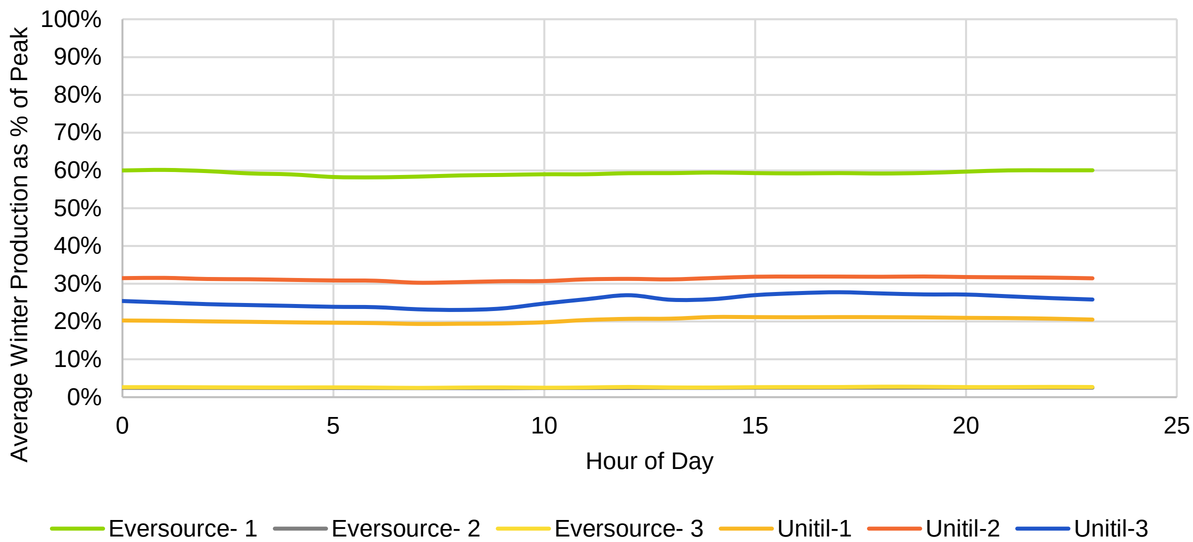
[50] The study did not include investigation of hydrological conditions at any potential sites near or adjacent to the 16 locations to develop representative production profiles.

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.

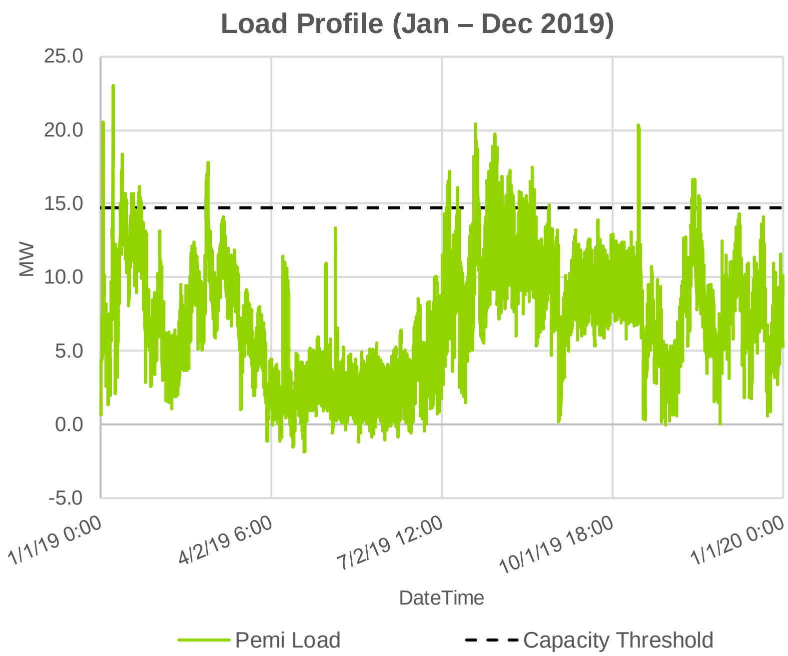
Pemi Substation (Bulk) Analysis

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

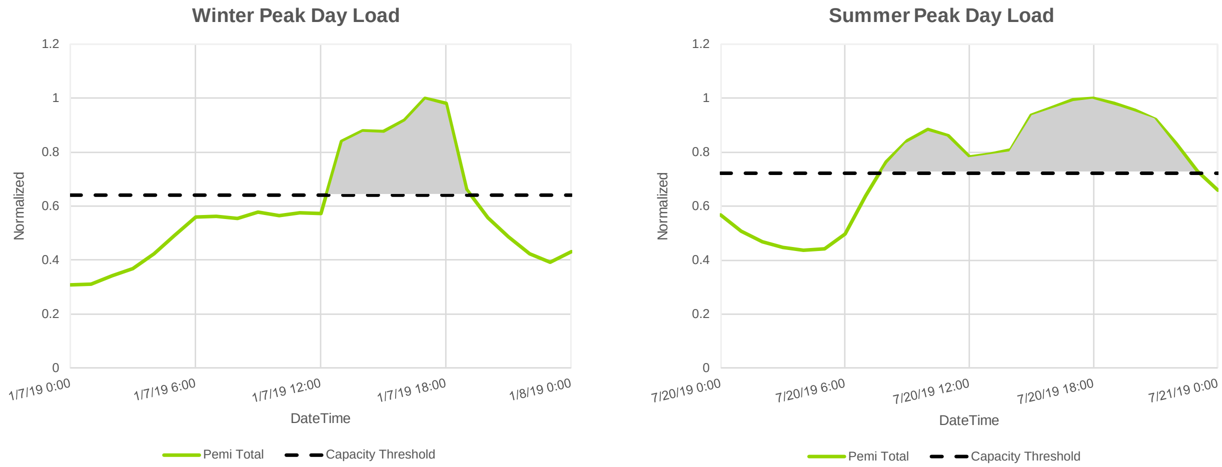
Table 24. Annual Load Profile and Capacity Threshold – Pemi Substation (Bulk)

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)

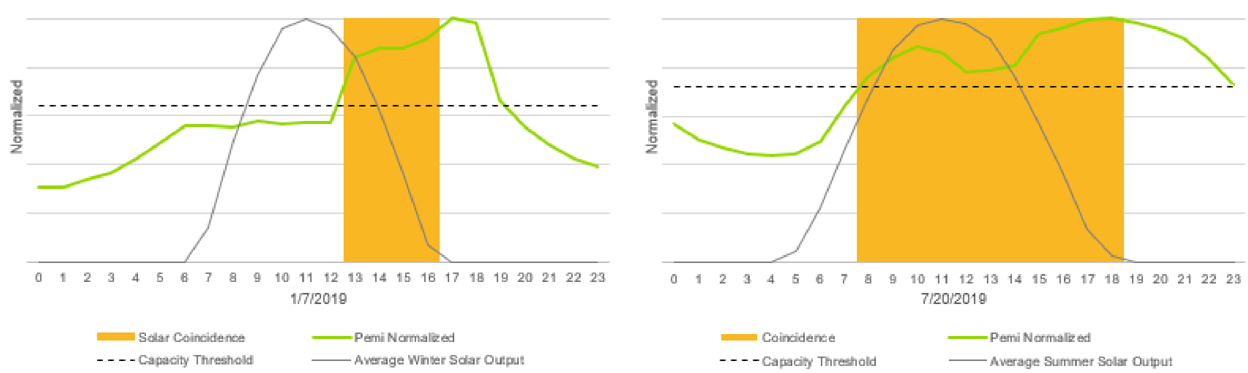


Source: Guidehouse, EDC data

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

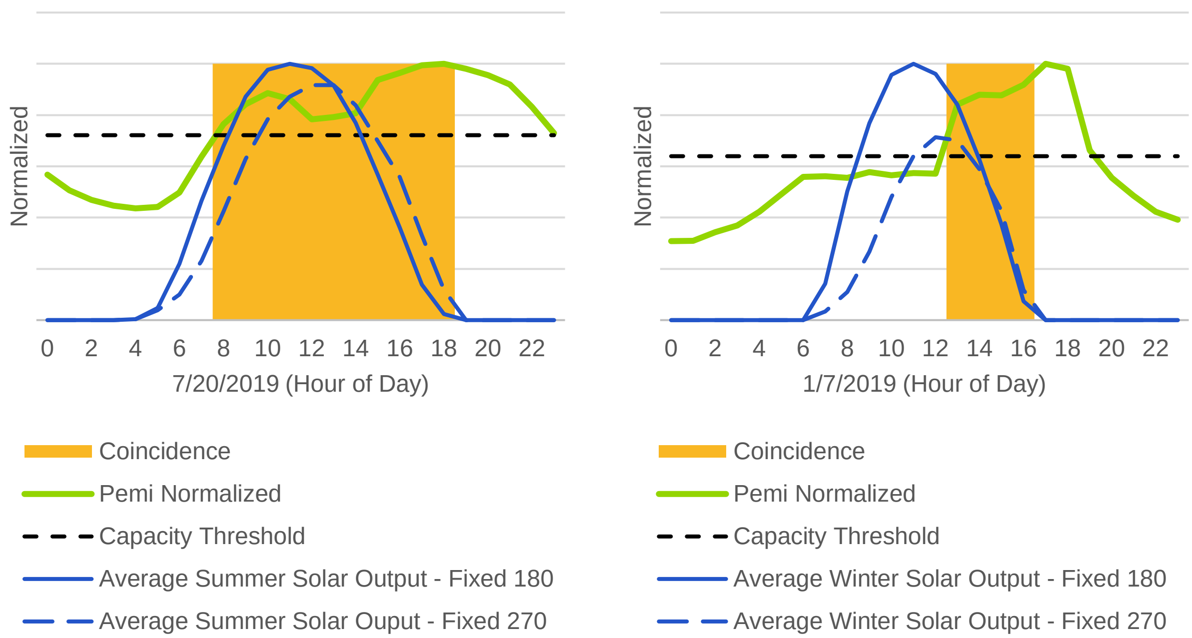


Source: Guidehouse, EDC data

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



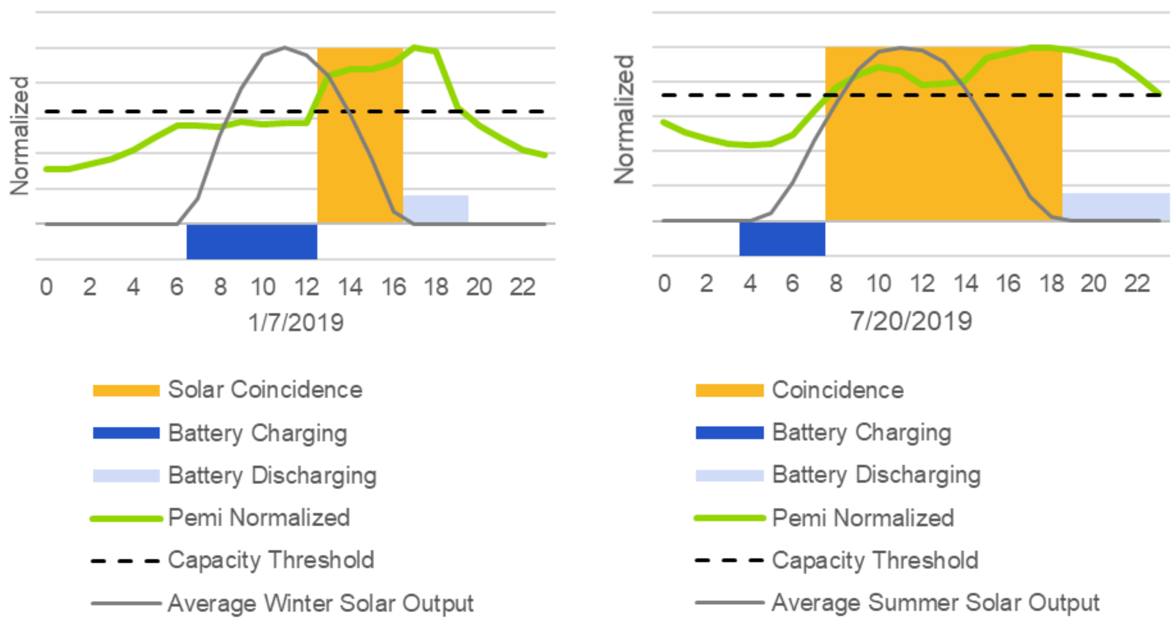
Source: Guidehouse, EDC data

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)

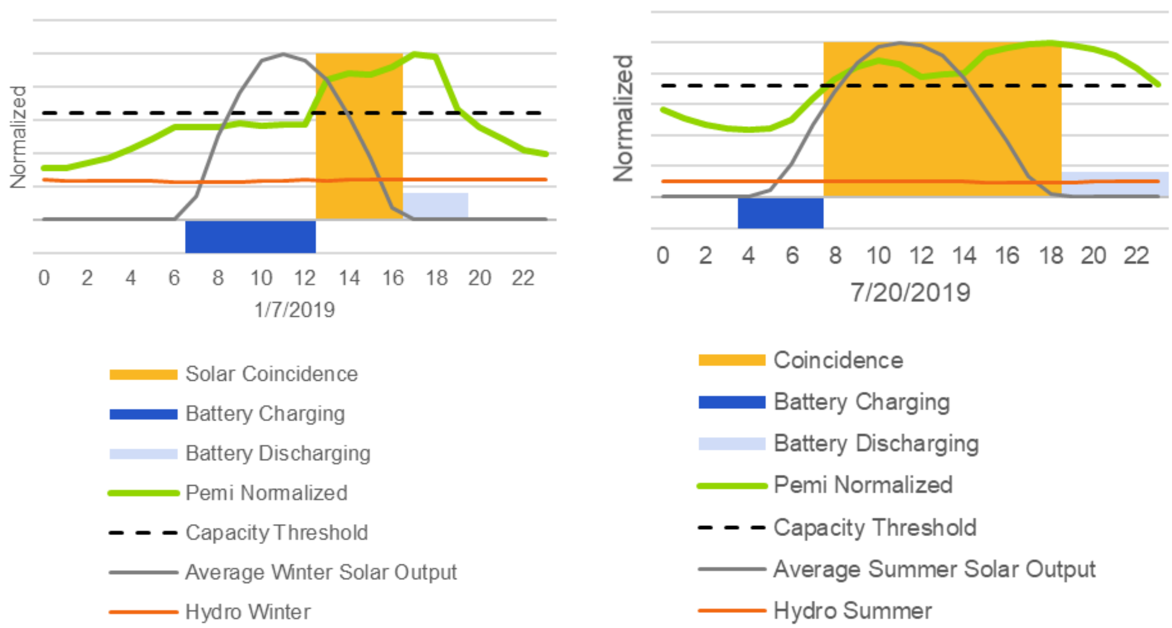


Source: Guidehouse, EDC data

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

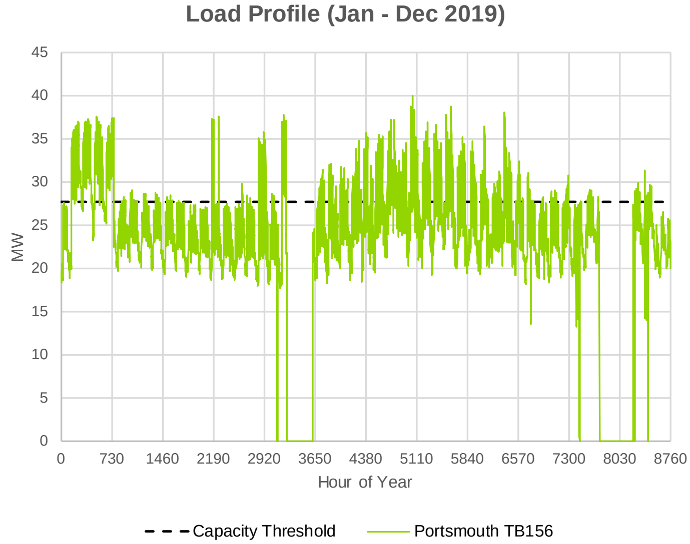
Figure 61 presents hourly profiles for the Portsmouth substation, a midday peaking bulk substation, where capacity deficiencies occur many hours during the year. These deficiencies occur during winter and summer months and are caused by insufficient transformation capacity to back up the contingency 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

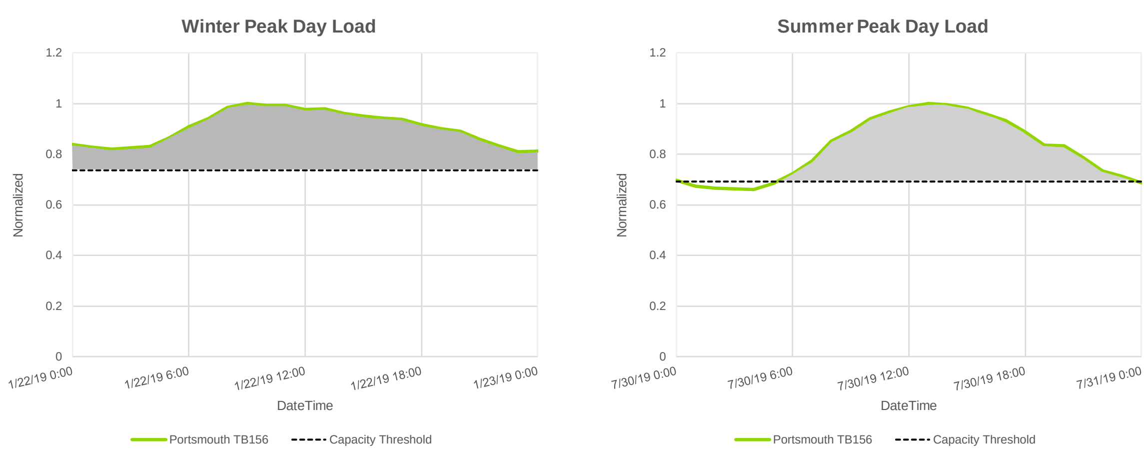
Table 25. Annual Load Profile and Capacity Threshold – Portsmouth Substation

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



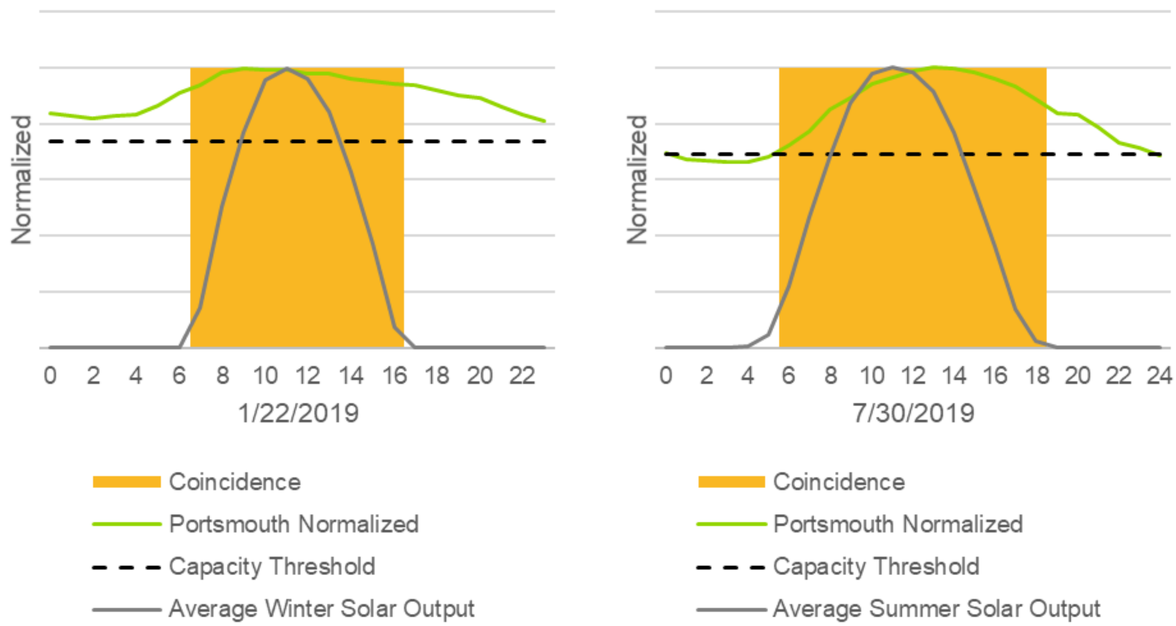
Source: Guidehouse, EDC data

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)



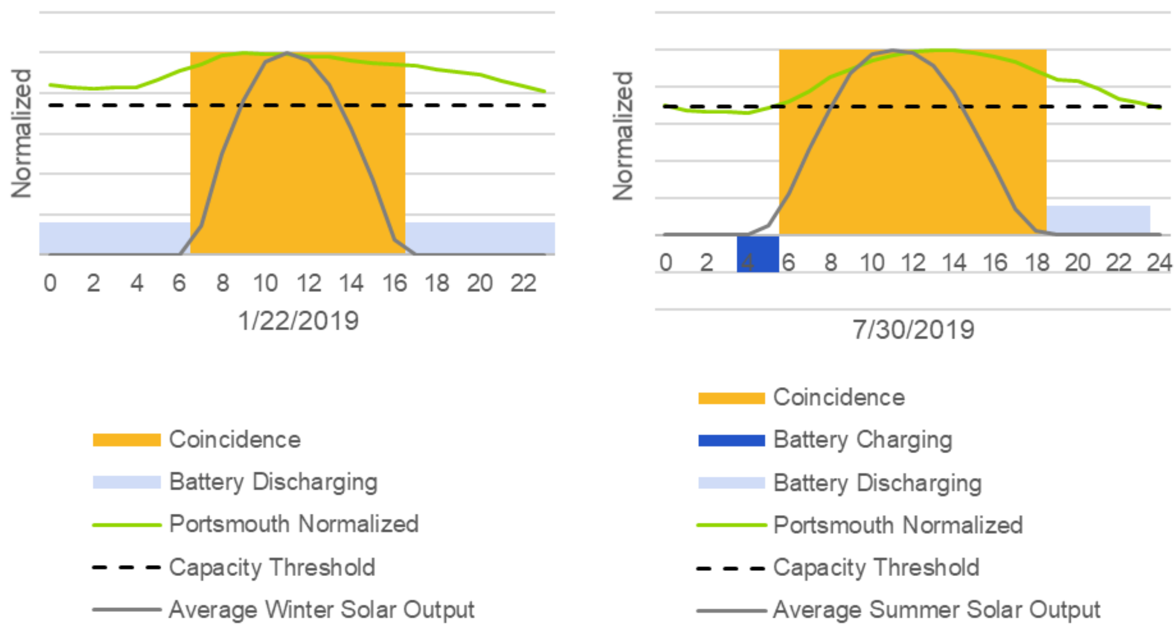
Source: Guidehouse, EDC data

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)

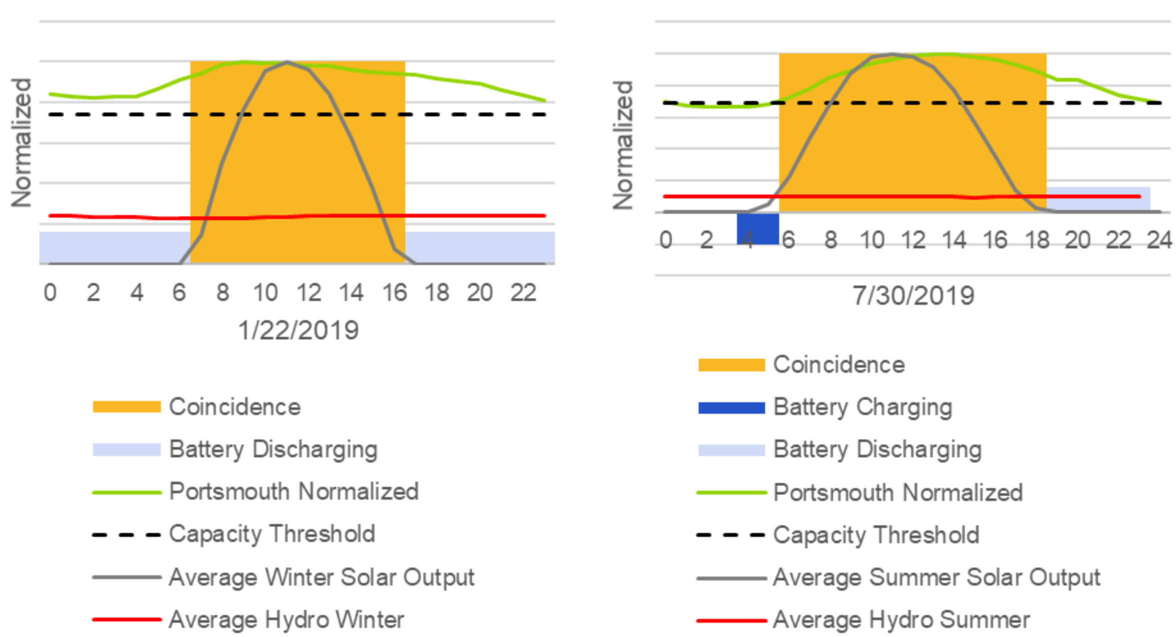


Source: Guidehouse, EDC data

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



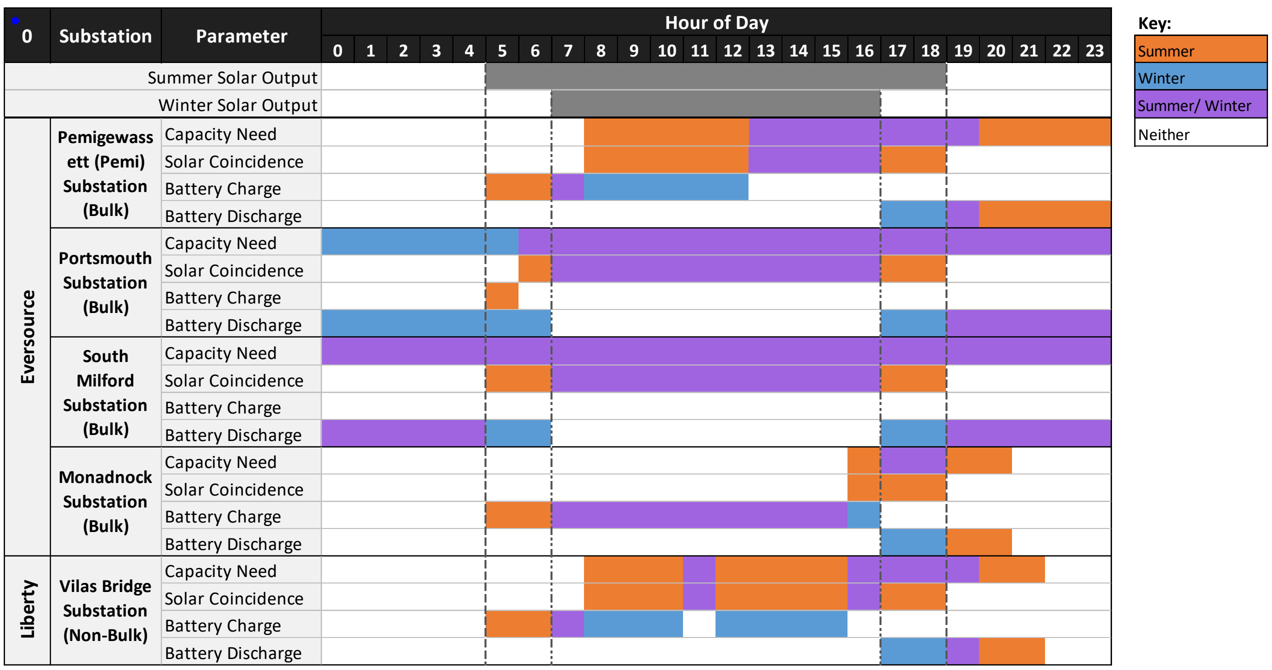
Source: Guidehouse, EDC data

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

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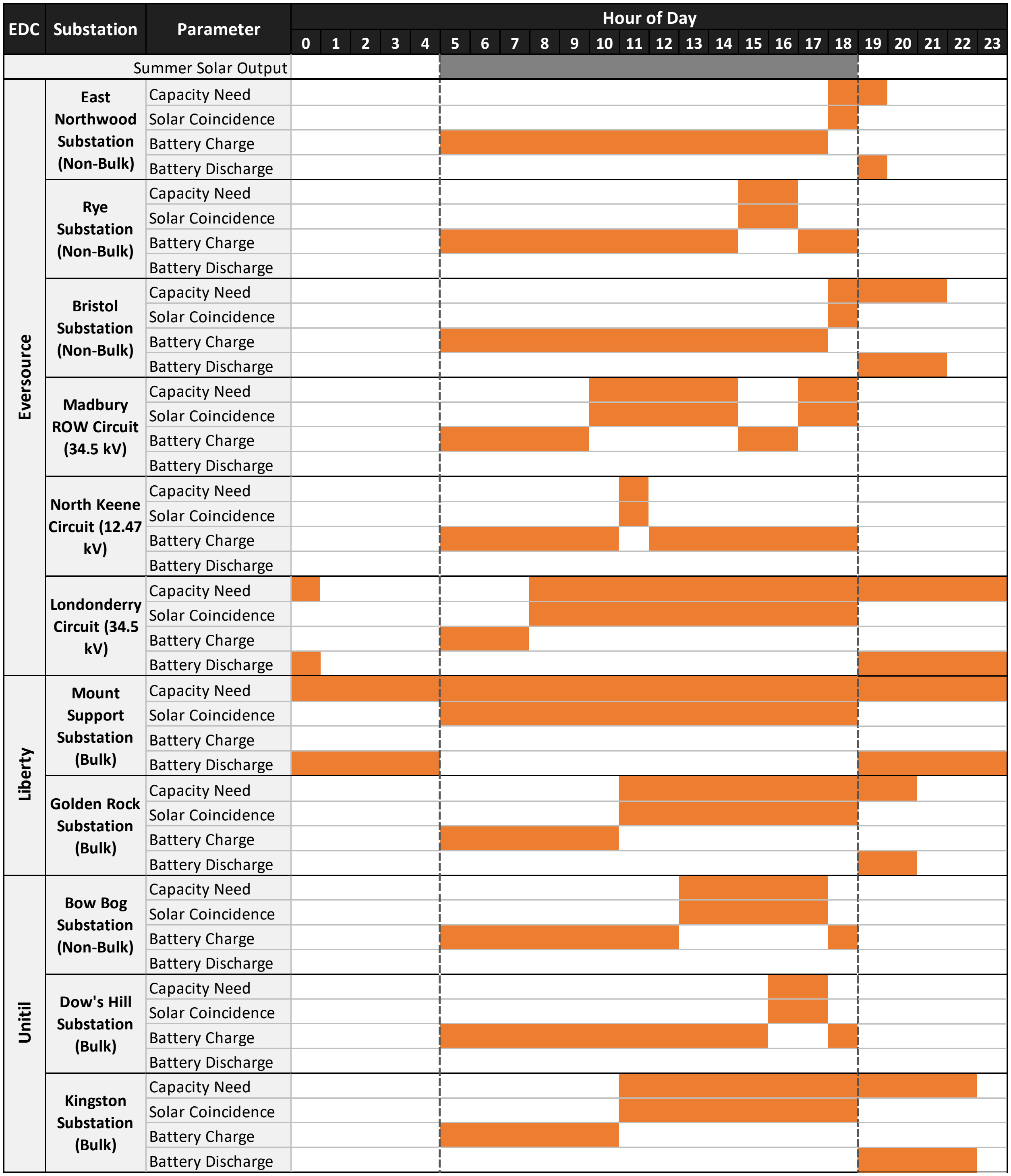
[52] Figure 64 excludes hydro production profiles as energy is produced for 24 hours, continuously throughout the days, for each season. Inclusion of hydro profiles would render the illustration unnecessarily complex.

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.

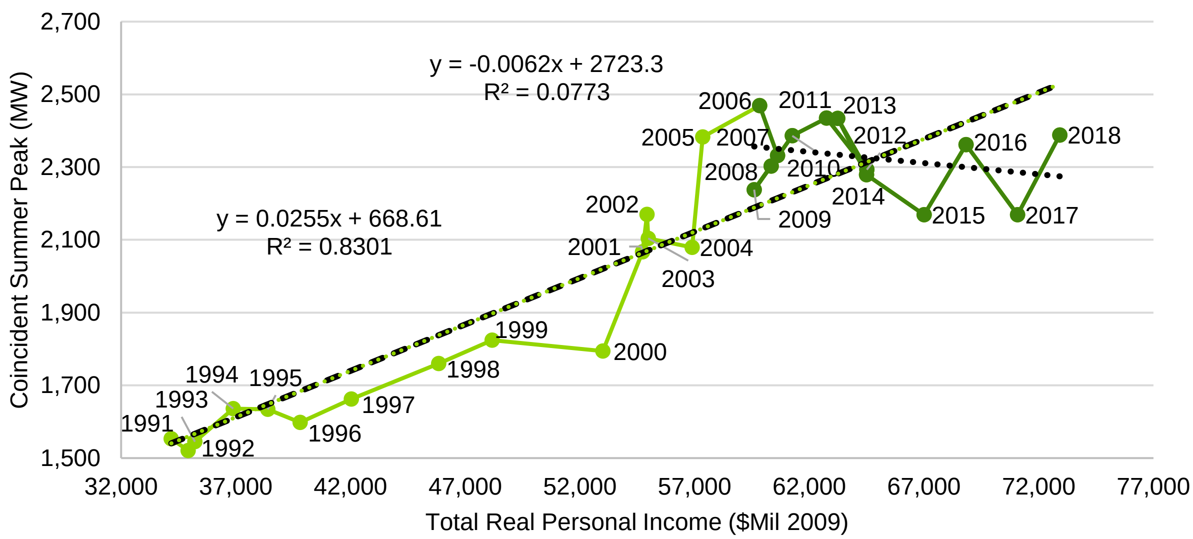
Appendix A.Detailed Methodology and Assumptions

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)

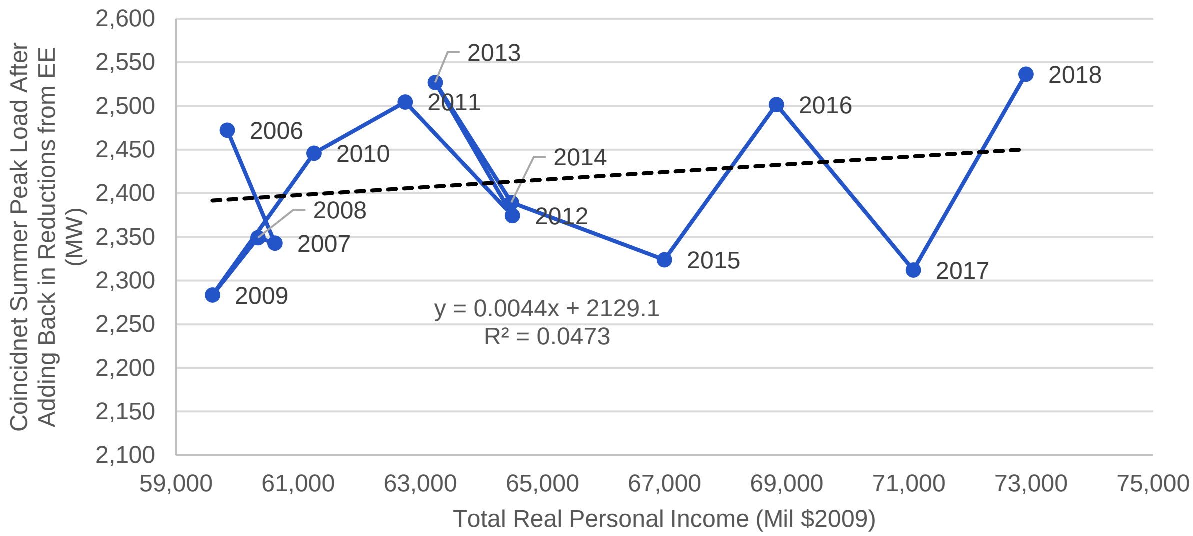


Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

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.

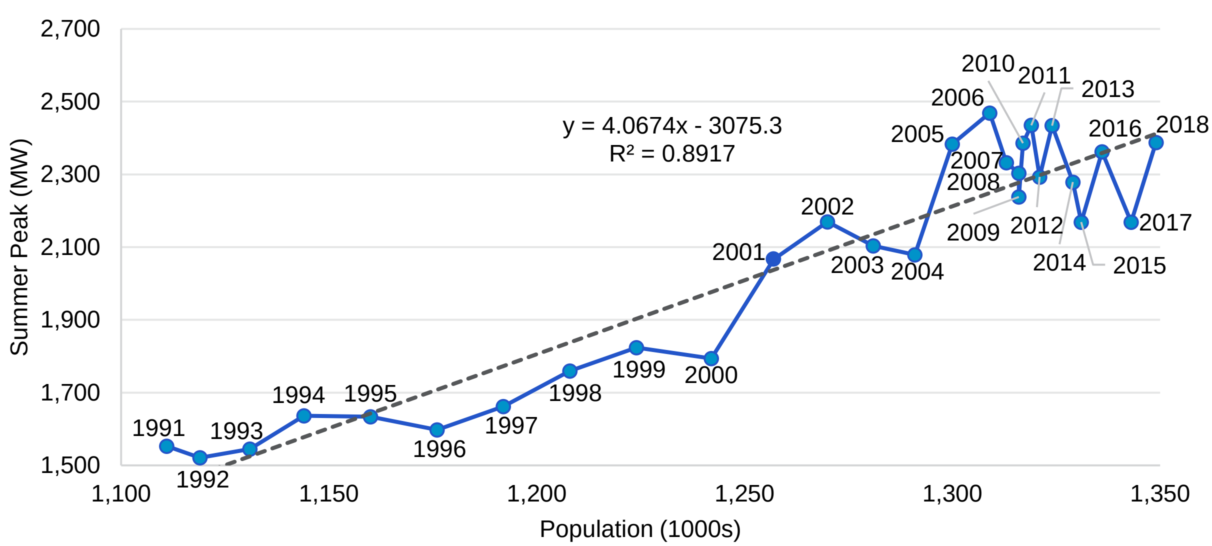
Figure A-2. Coincident Summer Peak After Adding Back in Peak Load Reductions from EE vs. Total Real Personal Income (2006-2018)



Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

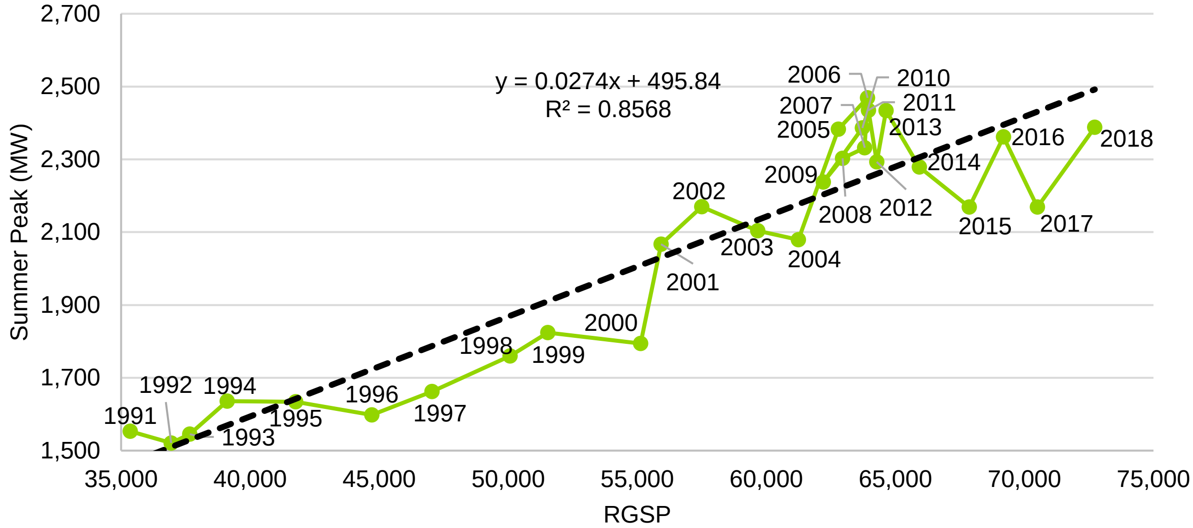
In addition to looking at the past 30 years and the past 12 years of summer peak as compared to total real personal income, the study also compared loading with total statewide population and real gross state product. The analysis revealed similar trends when considering total population and real gross 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)



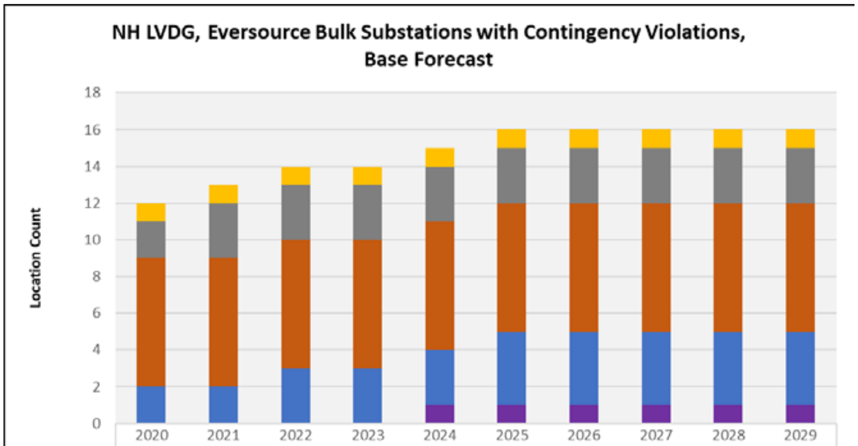
Source: ISO-NE, https://www.iso-ne.com/system-planning/system-forecasting/load-forecast/

A.2 Forward-Looking Violation Screening

Capacity Deficiency Analysis: Eversource- Base Forecast

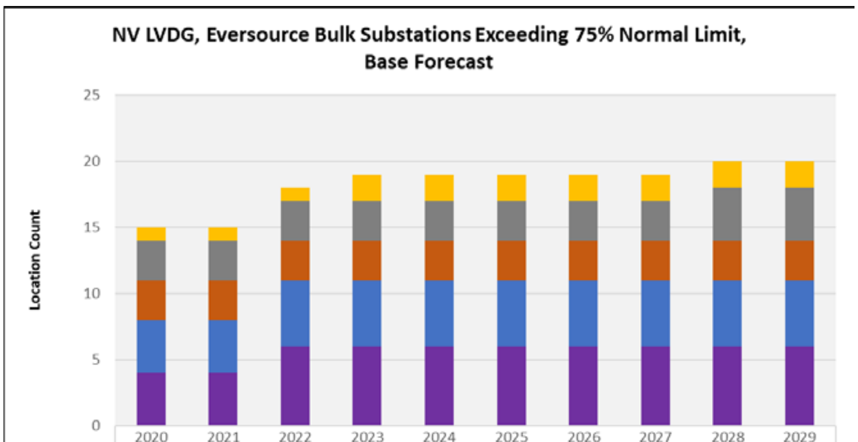
- In the base forecast Year 1, 12 substations do not meet Eversource's capacity planning criteria for contingencies (i.e., N-1 violations) and 15 bulk substations exceed 75% transformer normal limit rating[55]
- Six bulk substations have both normal and contingency violations during the 10-year forecast
- 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.



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	1	1	1	1	1	1	1	1	1	1
Southern	2	3	3	3	3	3	3	3	3	3
Northern	7	7	7	7	7	7	7	7	7	7
Eastern	2	2	3	3	3	4	4	4	4	4
Central	0	0	0	0	1	1	1	1	1	1

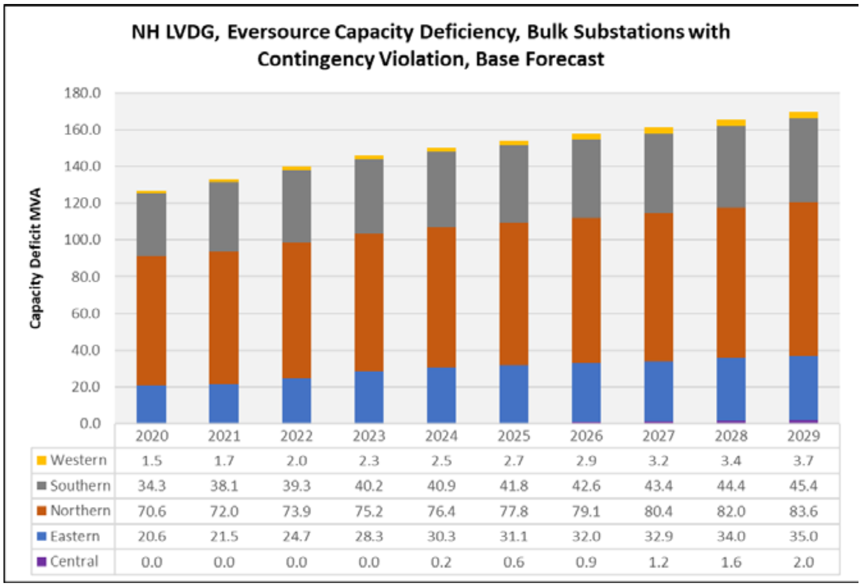
Source: Guidehouse, EDC data



	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	1	1	1	2	2	2	2	2	2	2
Southern	3	3	3	3	3	3	3	3	4	4
Northern	3	3	3	3	3	3	3	3	3	3
Eastern	4	4	5	5	5	5	5	5	5	5
Central	4	4	6	6	6	6	6	6	6	6

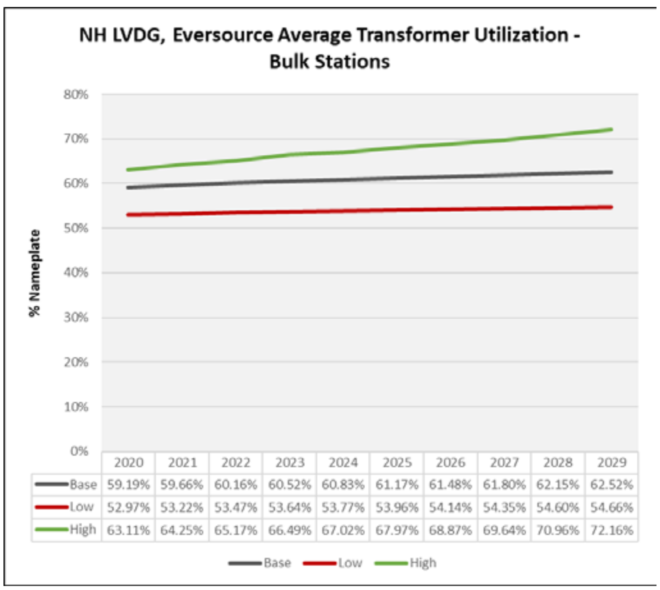
Source: Guidehouse, EDC data

- 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

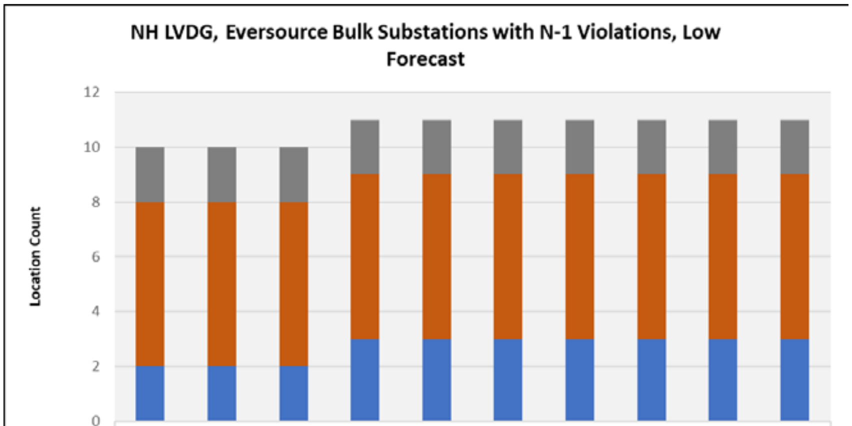


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Base	59.19%	59.66%	60.16%	60.52%	60.83%	61.17%	61.48%	61.80%	62.15%	62.52%
Low	52.97%	53.22%	53.47%	53.64%	53.77%	53.96%	54.14%	54.35%	54.60%	54.66%
High	63.11%	64.25%	65.17%	66.49%	67.02%	67.97%	68.87%	69.64%	70.96%	72.16%

Source: Guidehouse, EDC data

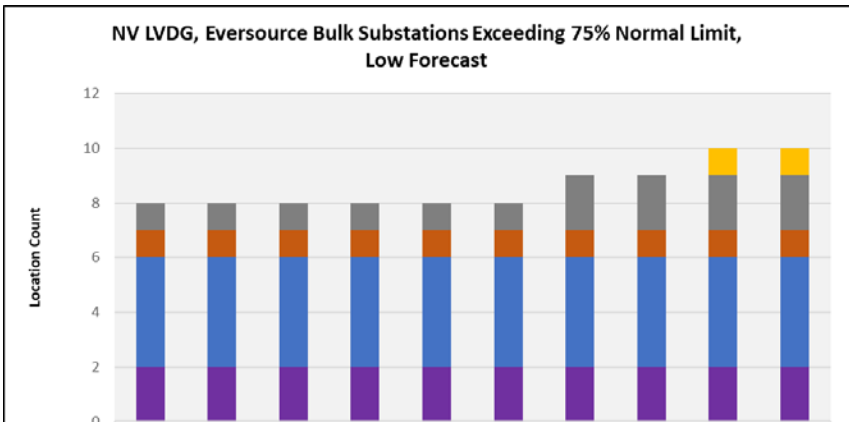
Capacity Deficiency Analysis: Eversource- Low Forecast

- 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

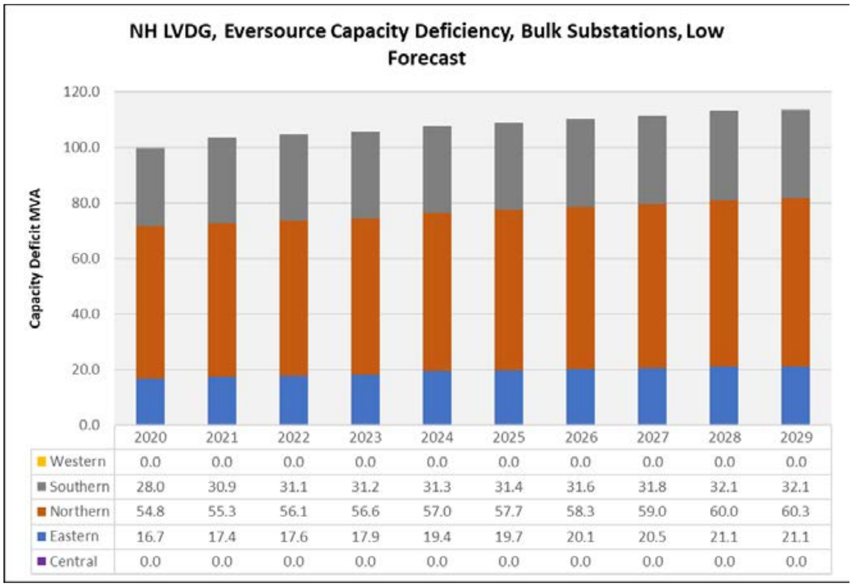
Source: Guidehouse, EDC data



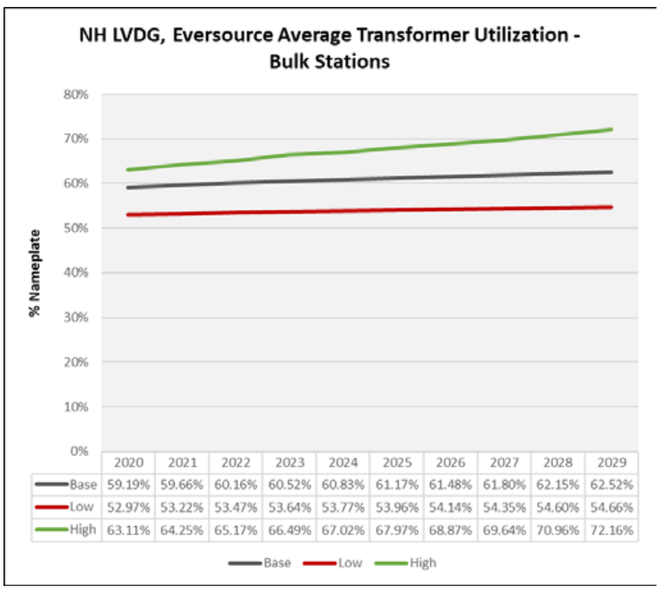
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0	0	0	0	0	0	0	0	1	1
Southern	1	1	1	1	1	1	2	2	2	2
Northern	1	1	1	1	1	1	1	1	1	1
Eastern	4	4	4	4	4	4	4	4	4	4
Central	2	2	2	2	2	2	2	2	2	2

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



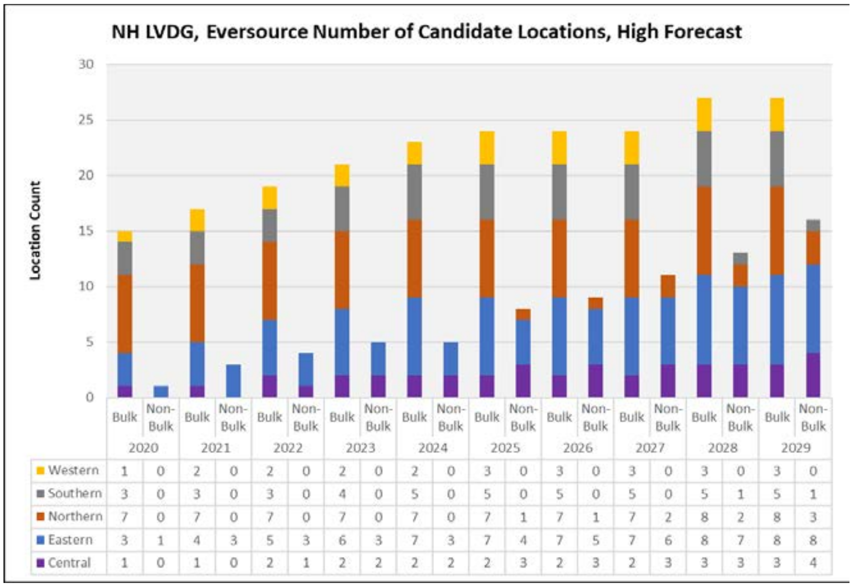
Source: Guidehouse, EDC data



Source: Guidehouse, EDC data

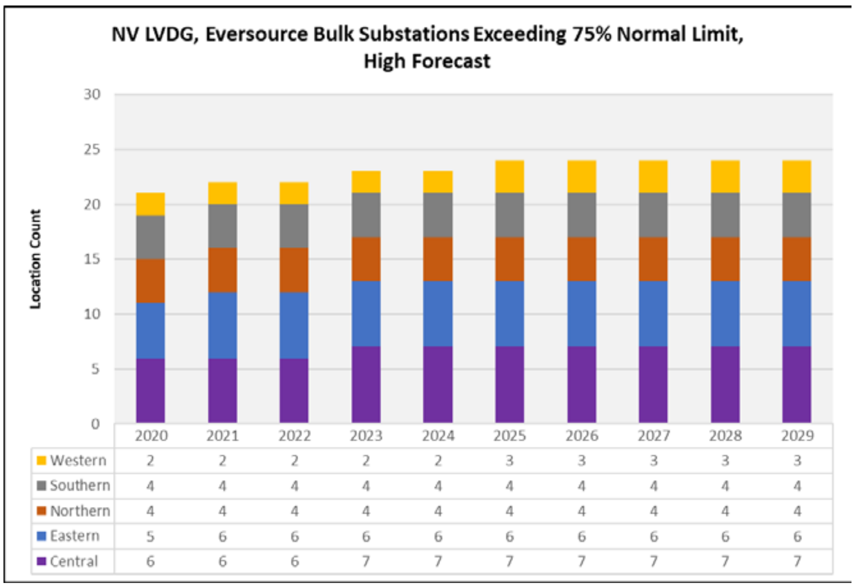
Capacity Deficiency Analysis: Eversource- High Forecast

- 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

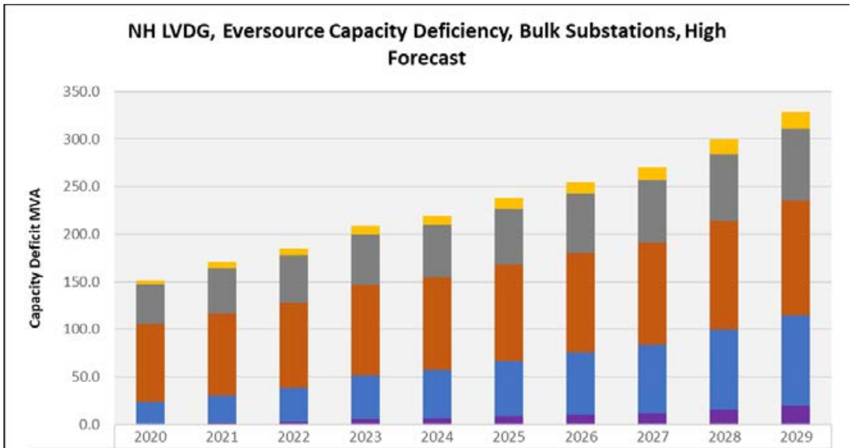
Source: Guidehouse, EDC data



	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

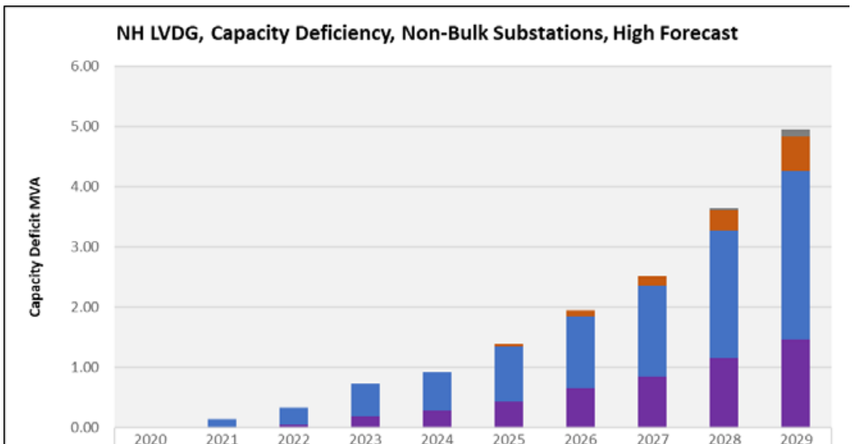
Source: Guidehouse, EDC data

- 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

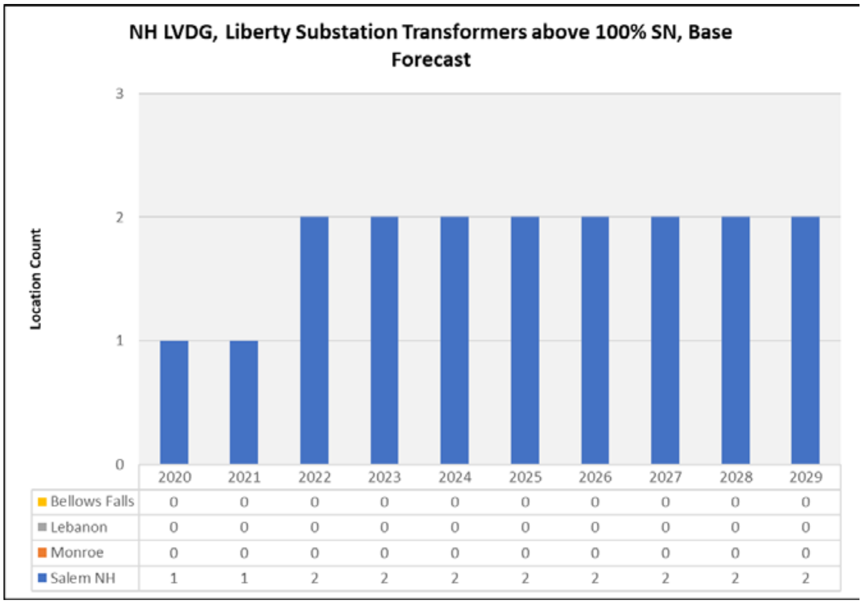


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Western	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Southern	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.12
Northern	0.00	0.00	0.00	0.00	0.00	0.05	0.10	0.15	0.35	0.58
Eastern	0.02	0.14	0.28	0.53	0.65	0.91	1.20	1.51	2.12	2.79
Central	0.00	0.00	0.05	0.19	0.27	0.43	0.65	0.84	1.15	1.46

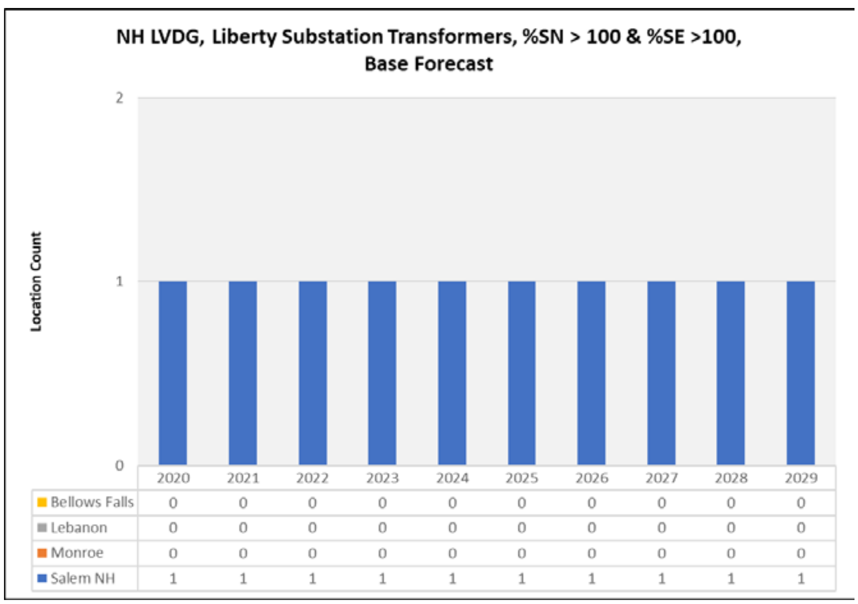
Source: Guidehouse, EDC data

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

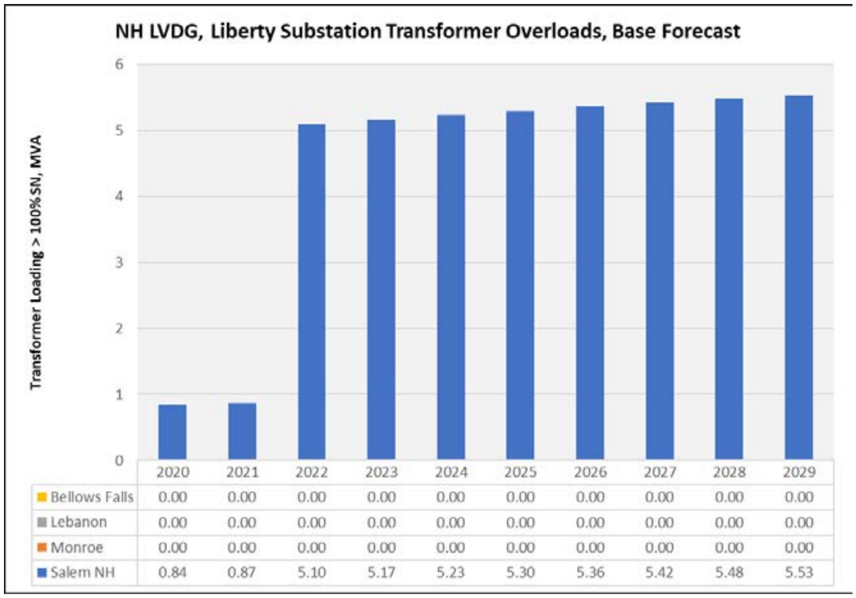


Source: Guidehouse, EDC data

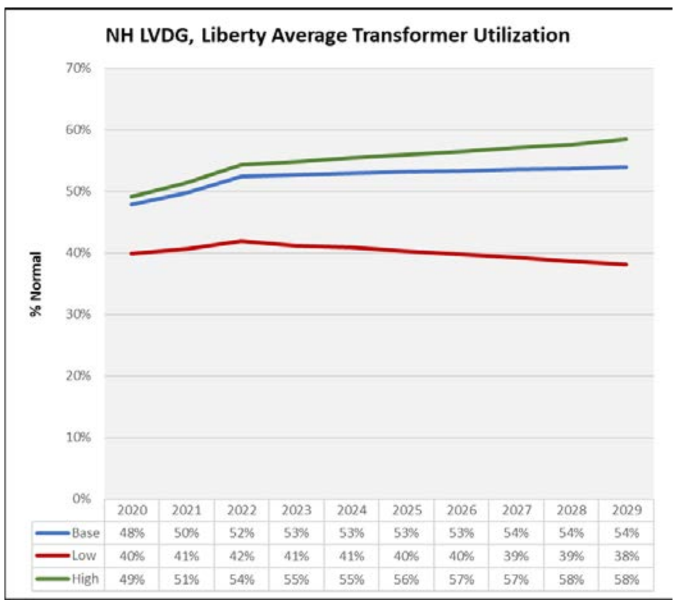


Source: Guidehouse, EDC data

- 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



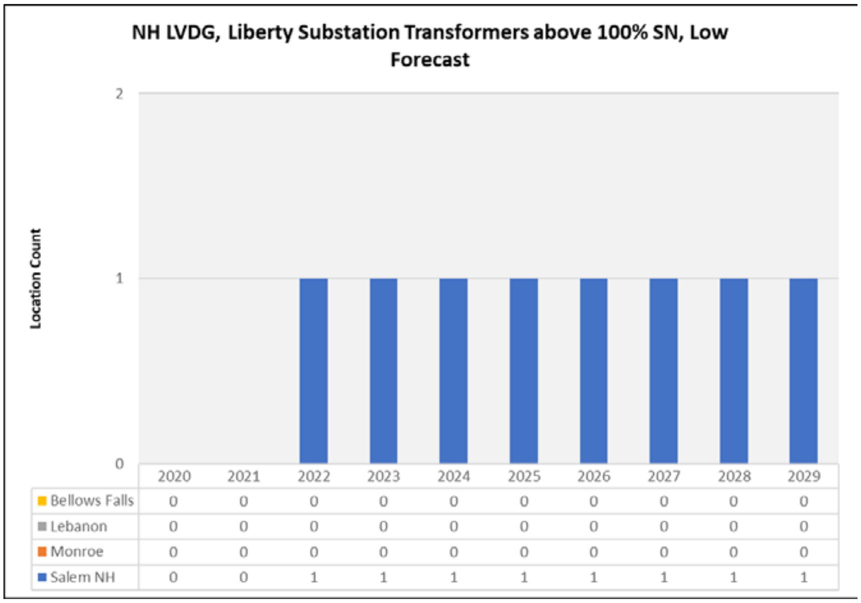
Source: Guidehouse, EDC data



Source: Guidehouse, EDC data

Capacity Deficiency Analysis: Liberty - Low Forecast

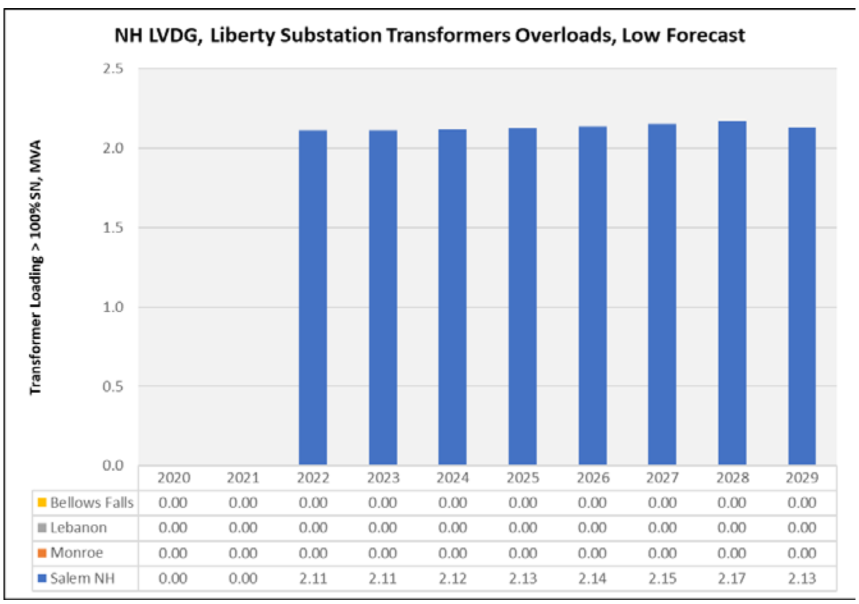
- For the low load forecast, one substation transformer exceeds 100% normal ratings starting in 2022
- None of the substation transformers exceed both 100% normal and 100% emergency ratings



	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

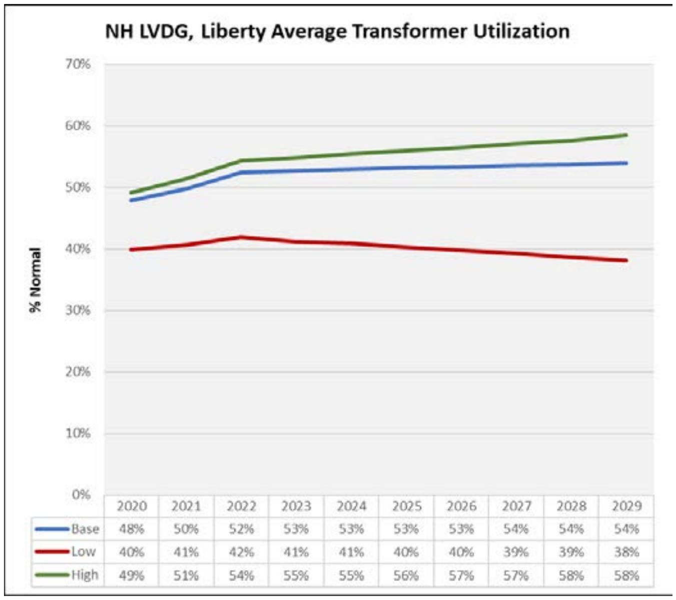
Source: Guidehouse, EDC data

- 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

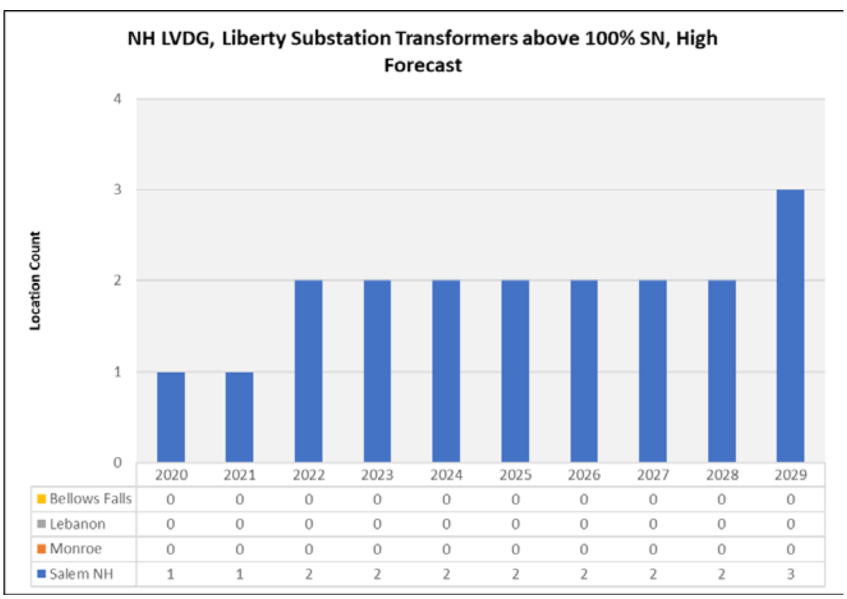
Source: Guidehouse, EDC data



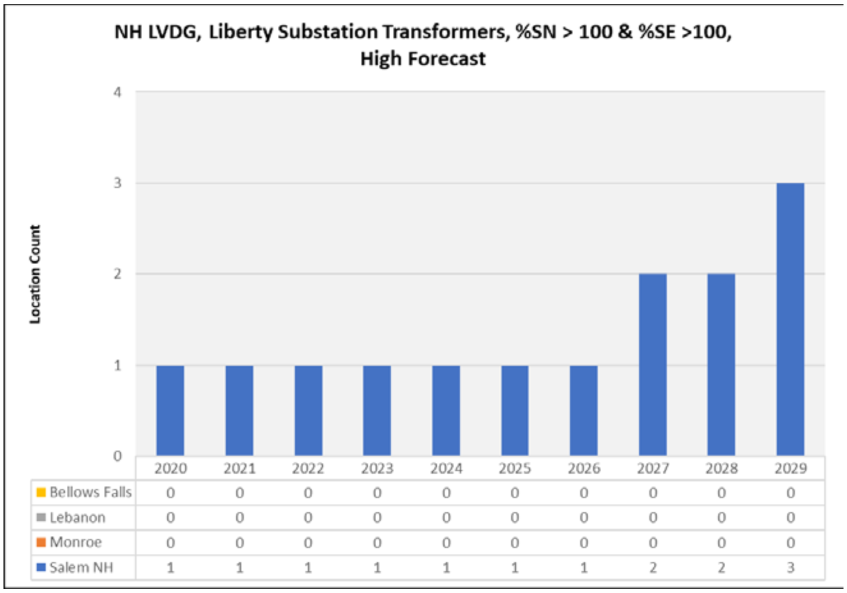
Source: Guidehouse, EDC data

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

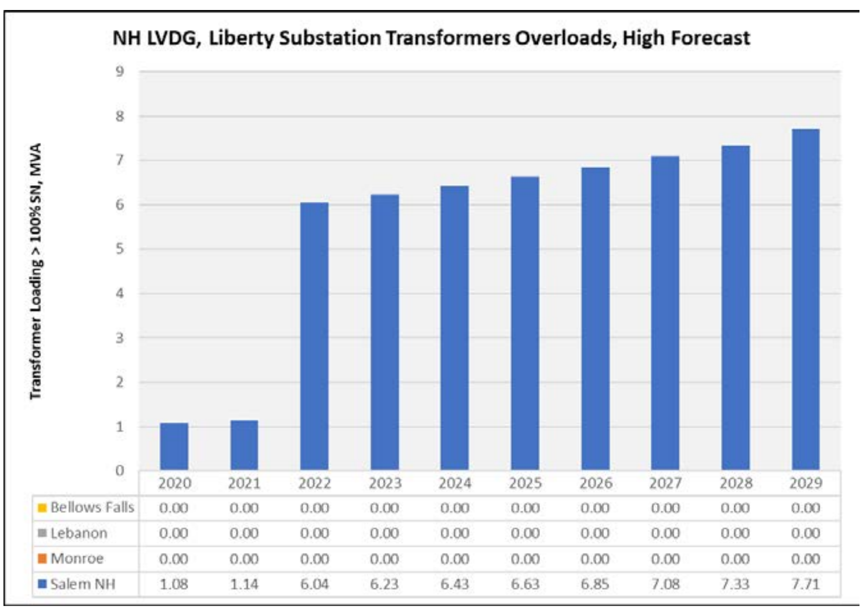


Source: Guidehouse, EDC data

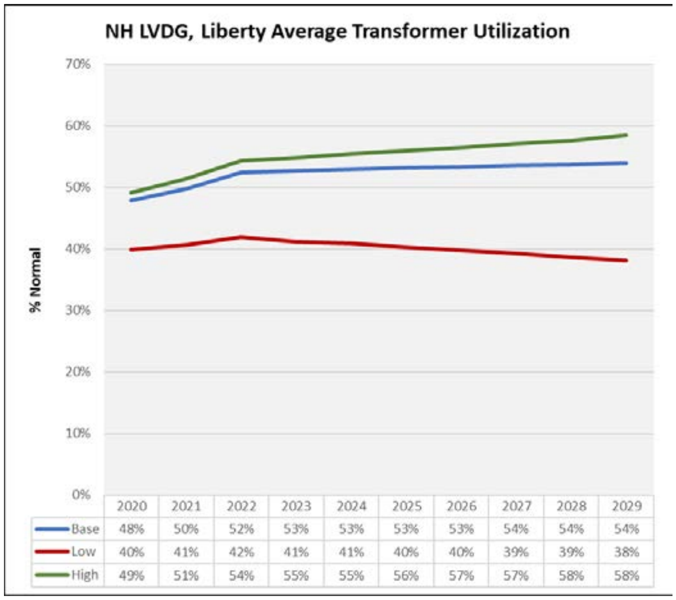


Source: Guidehouse, EDC data

- 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



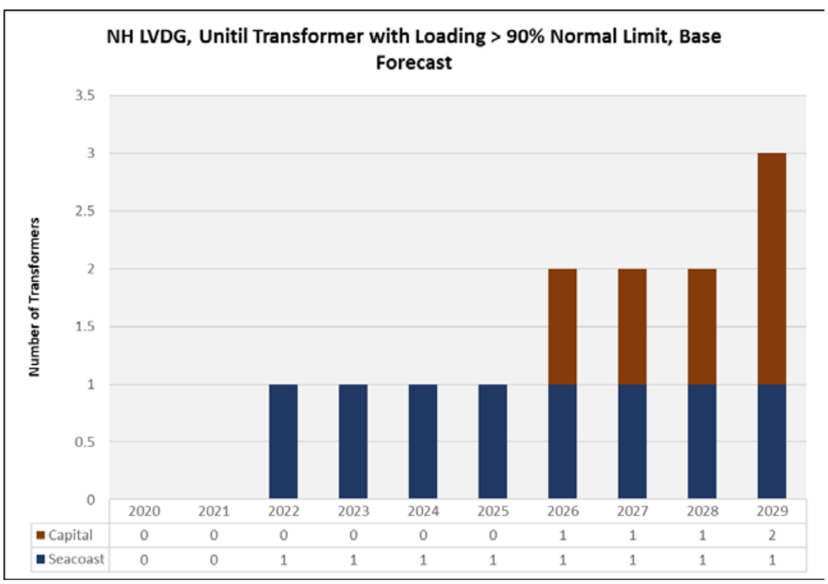
Source: Guidehouse, EDC data



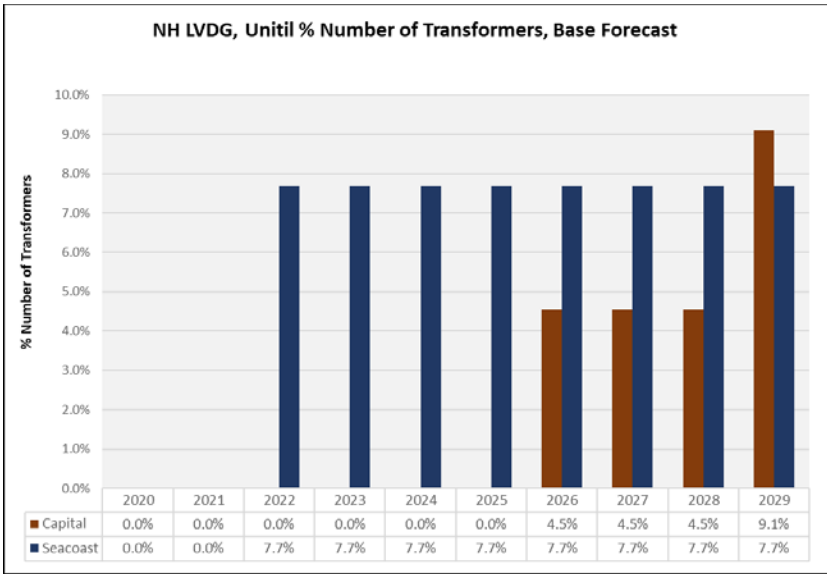
Source: Guidehouse, EDC data

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

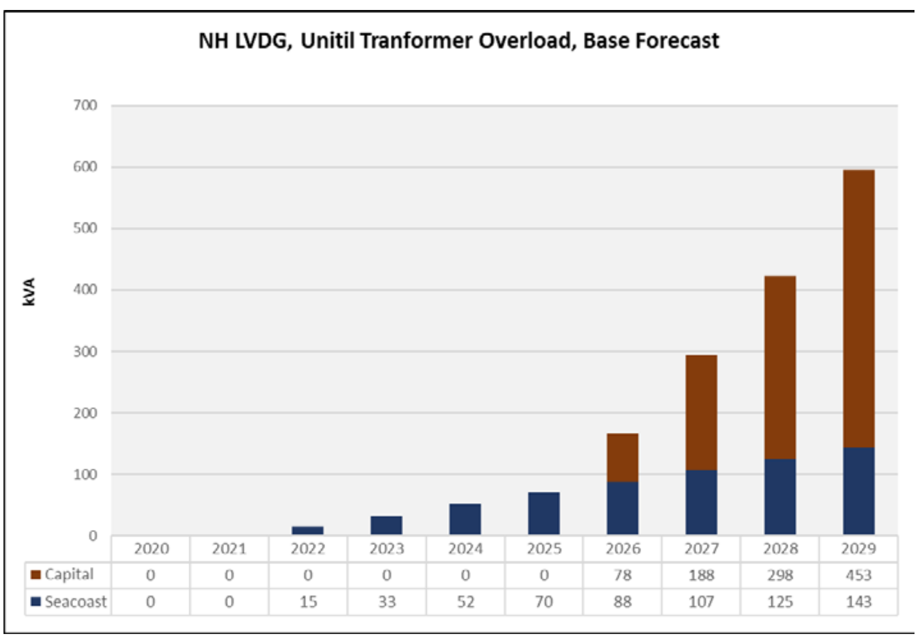


Source: Guidehouse, EDC data

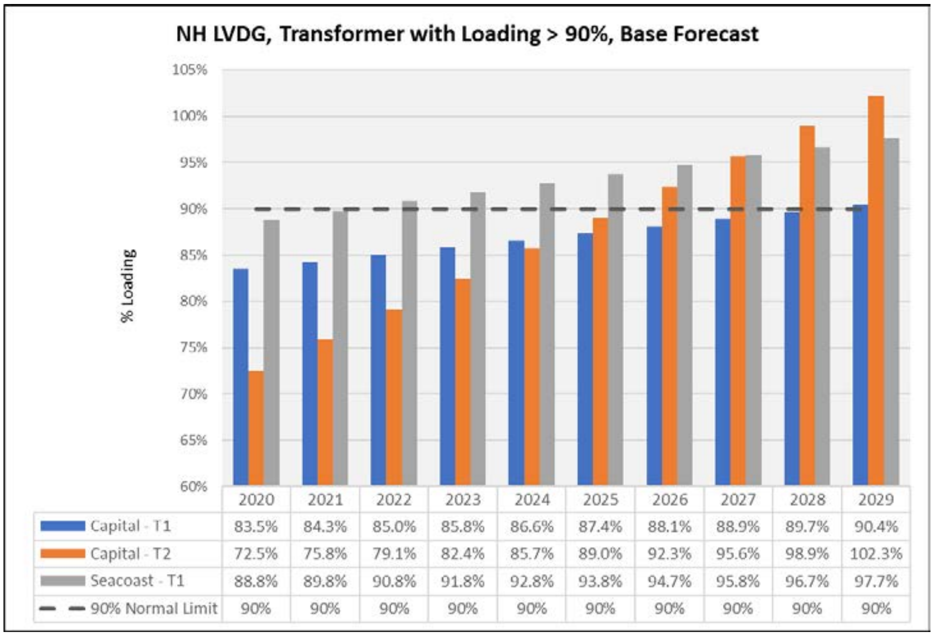


Source: Guidehouse, EDC data

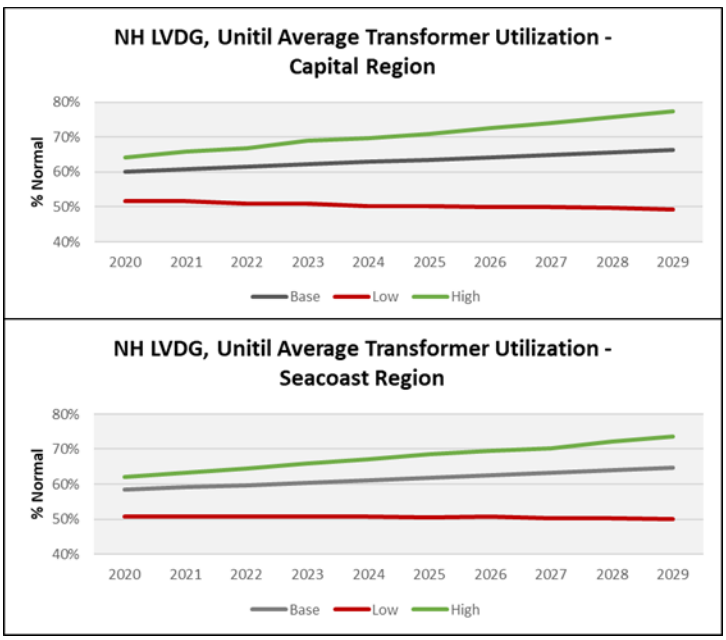
- Three substation transformers exceed Unitil's 90% criteria for normal loading limit for the 10-year base load forecast
- Two transformers in the capital region
- One transformer in the seacoast region



Source: Guidehouse, EDC data



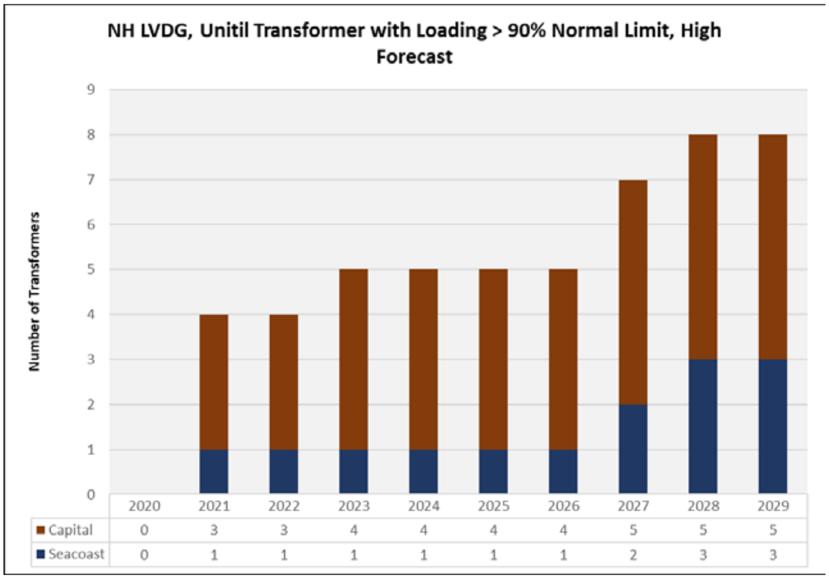
Source: Guidehouse, EDC data



Source: Guidehouse, EDC data

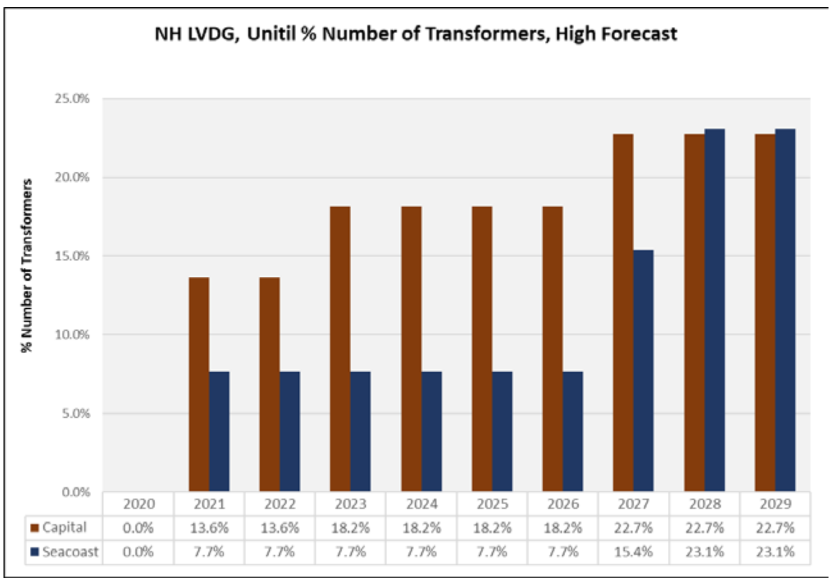
Capacity Deficiency Analysis: Unitil- High Forecast

- 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

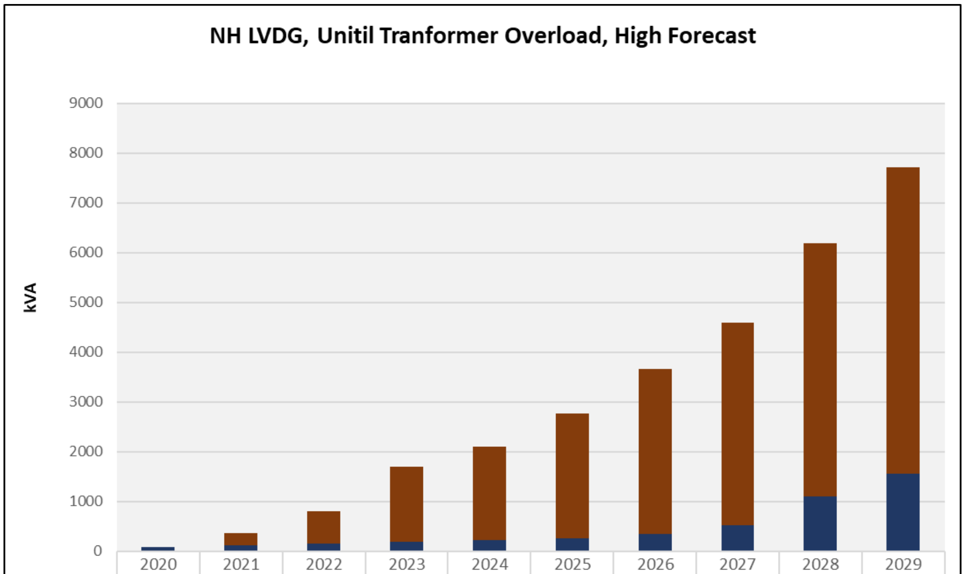
Source: Guidehouse, EDC data



	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%

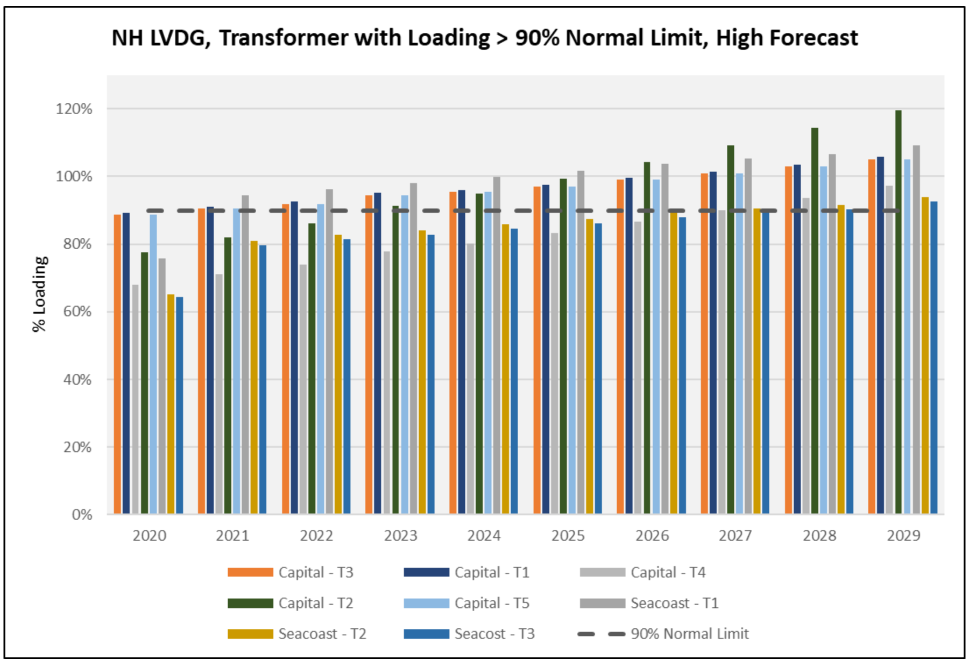
Source: Guidehouse, EDC data

- Eight substation transformers exceed Unitil's 90% normal loading limit for the 10-year high forecast case
- Transformer loadings increase significantly for High Case

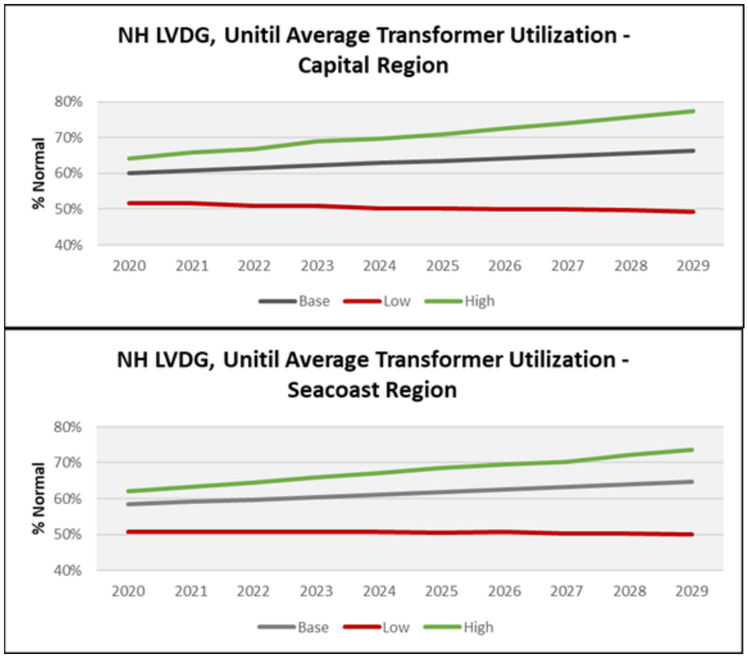


	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0	238	659	1505	1889	2505	3312	4080	5098	6171
Seacoast	82	117	149	185	217	256	340	517	1090	1546

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.

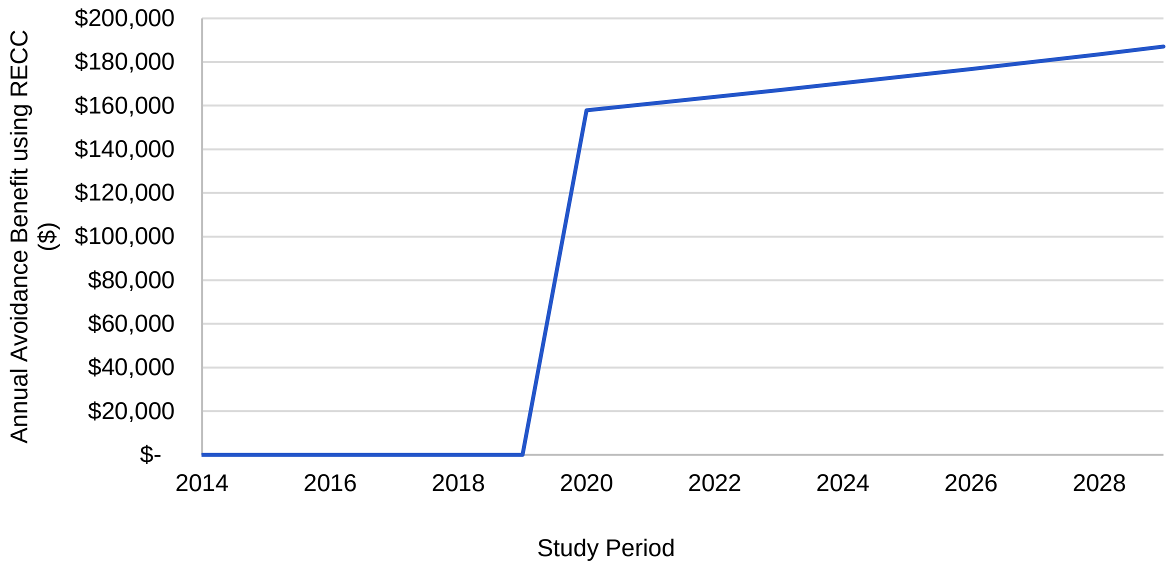
Appendix D. Economic Analysis

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]

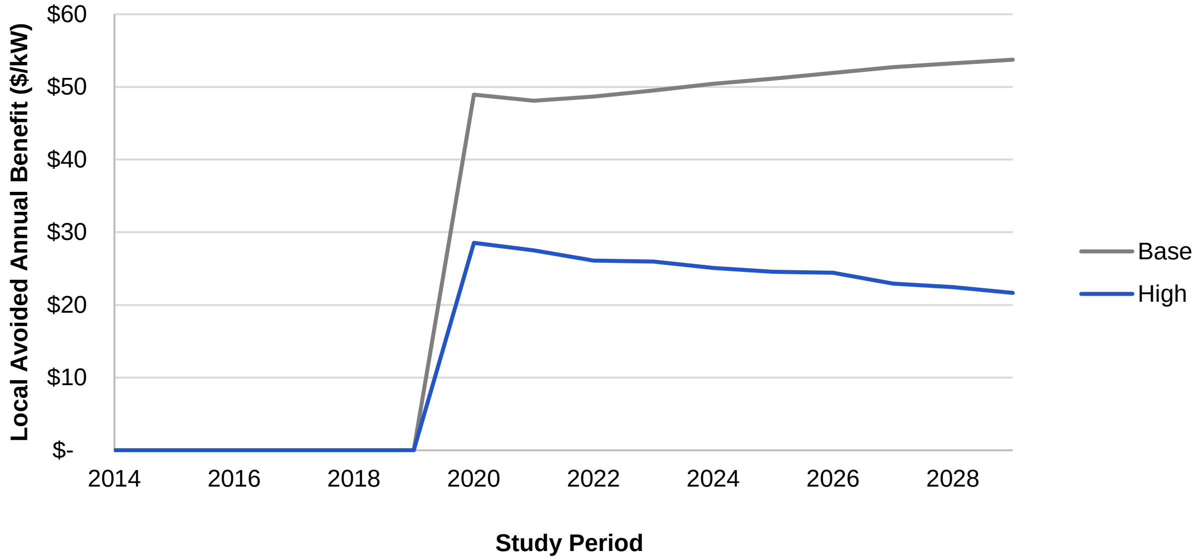
Figure D-1. Annual Avoidance Value – Madbury ROW Circuit (34.5 kV)



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)

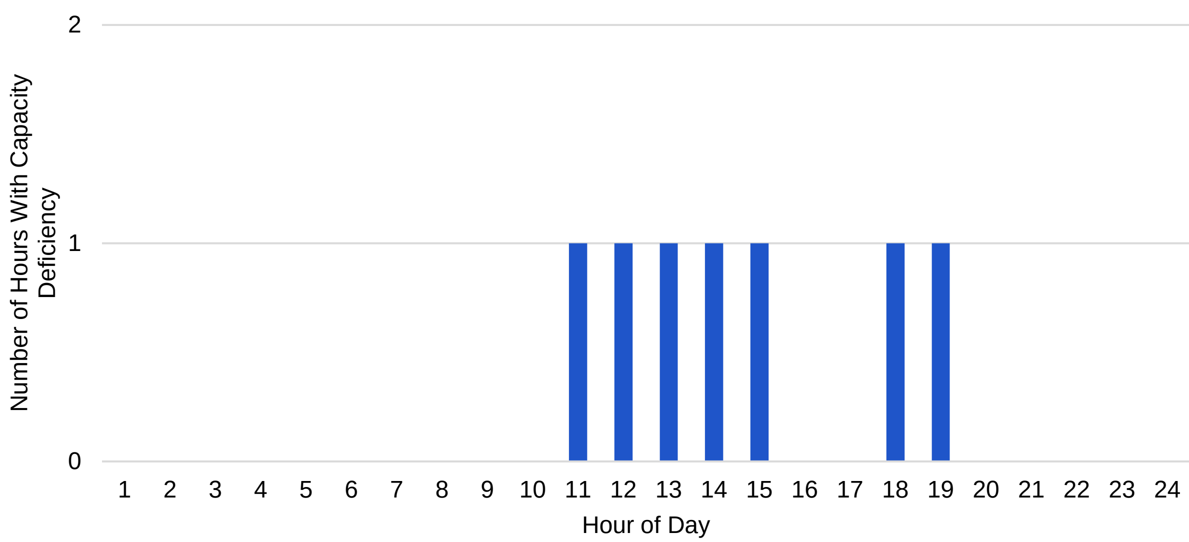


Source: Guidehouse, EDC data

Example Hourly Local Value Calculation for Madbury ROW Circuit (34.5 kV):

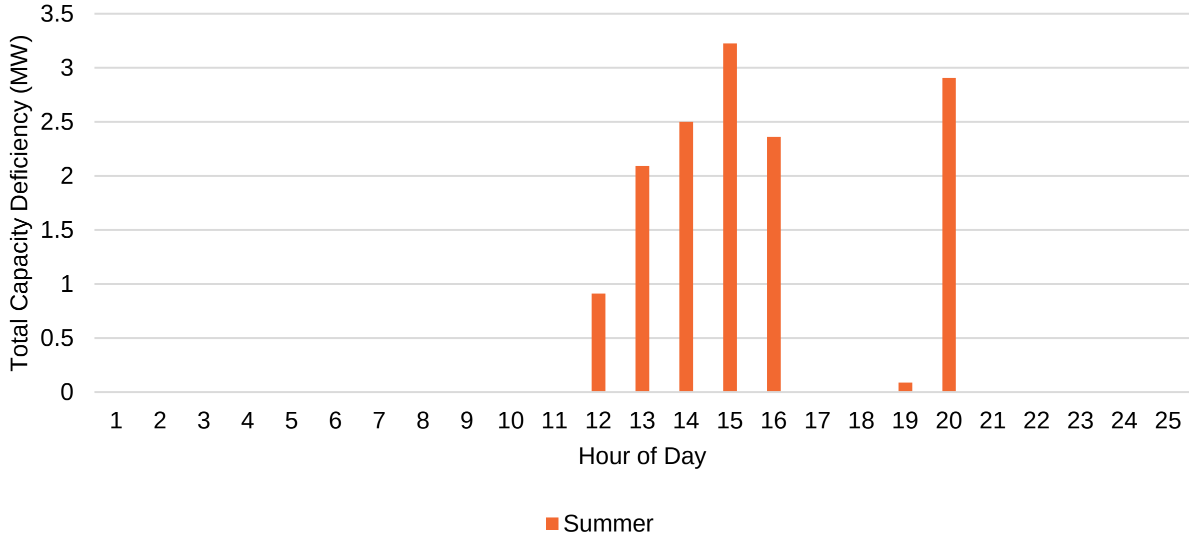
- Since Madbury ROW only has 1 day of capacity deficiency, the hourly and yearly analysis provide the same results.

Figure D-3. Number of Hours with Capacity Deficiency – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

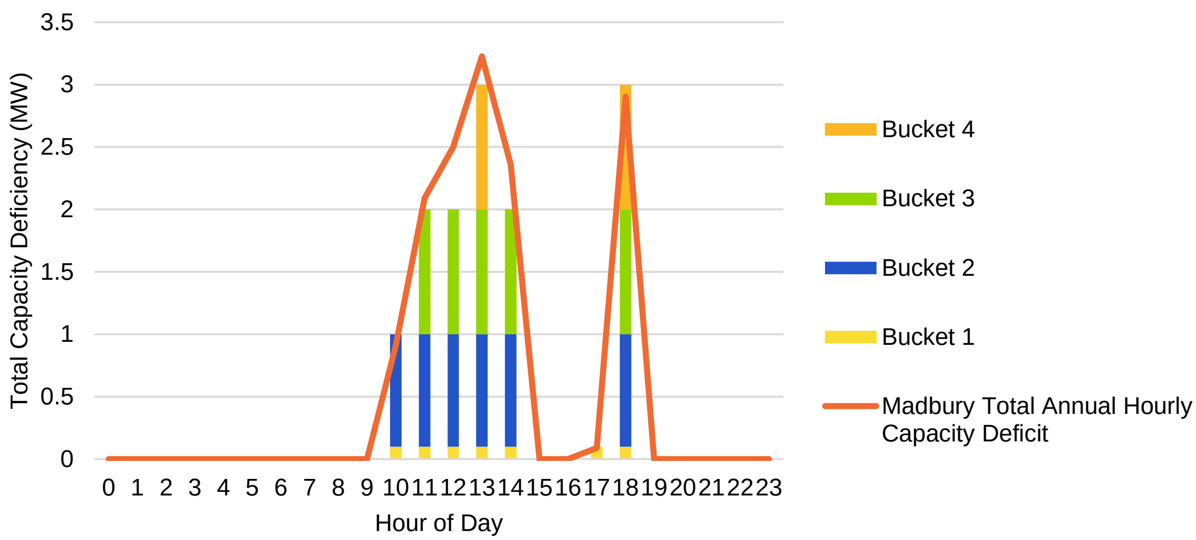
Figure D-4. Seasonal Capacity Deficiency Analysis – Madbury ROW Circuit (34.5 kV)



Source: Guidehouse, EDC data

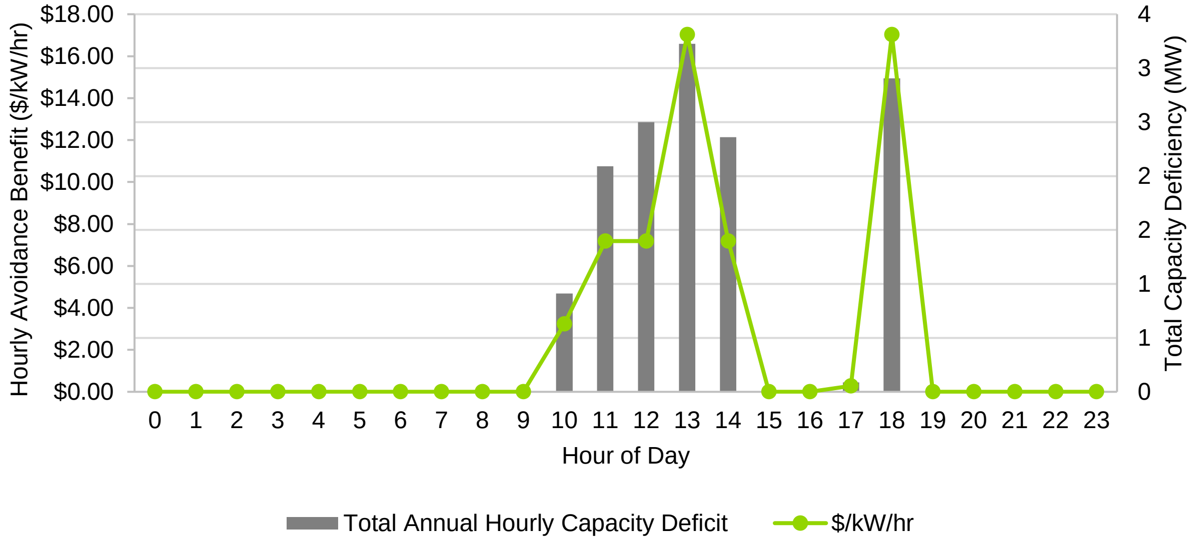
Madbury has two spikes on the peak day, but only four capacity deficiency buckets.

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)

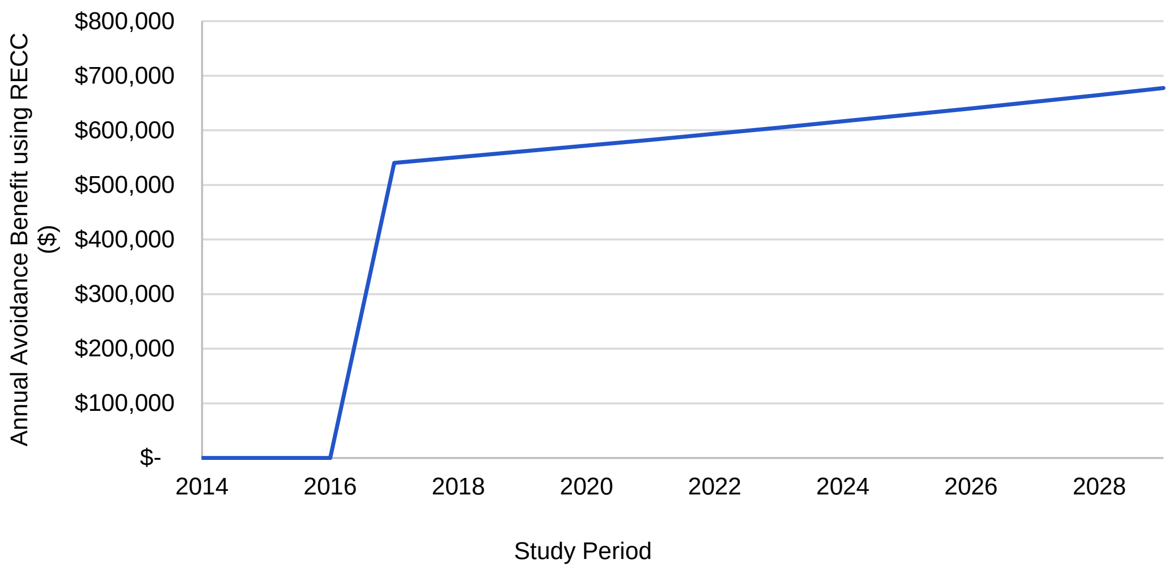


Source: Guidehouse, EDC data

Additional Example #2 - Mount Support Substation Yearly and Hourly Economic Analysis (EDC: Liberty):

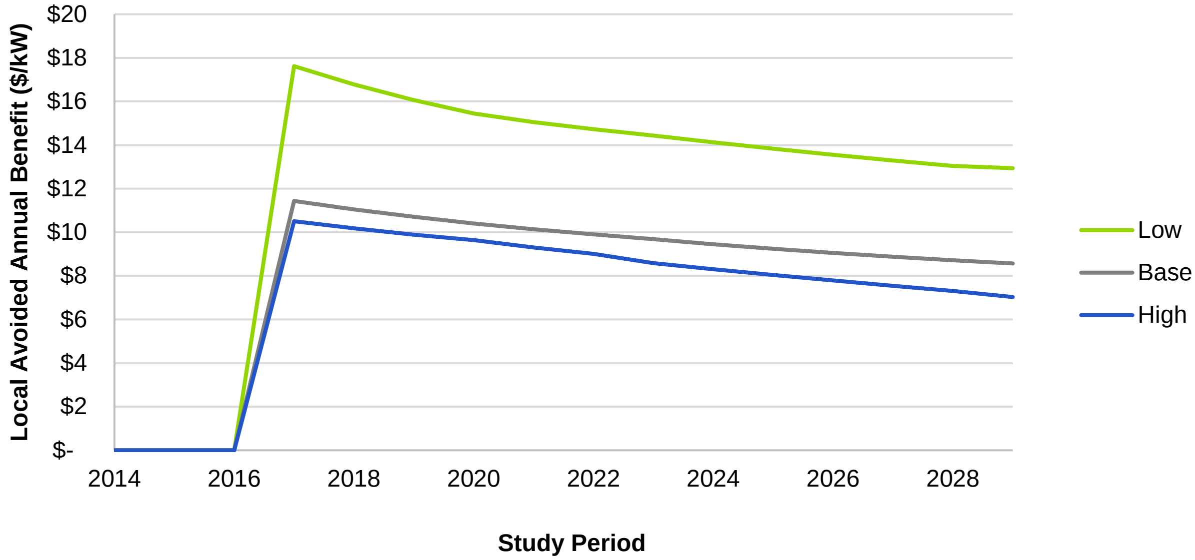
The annual avoidance value begins in 2017 and continues throughout the study period.

Figure D-7. Annual Avoidance Value – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

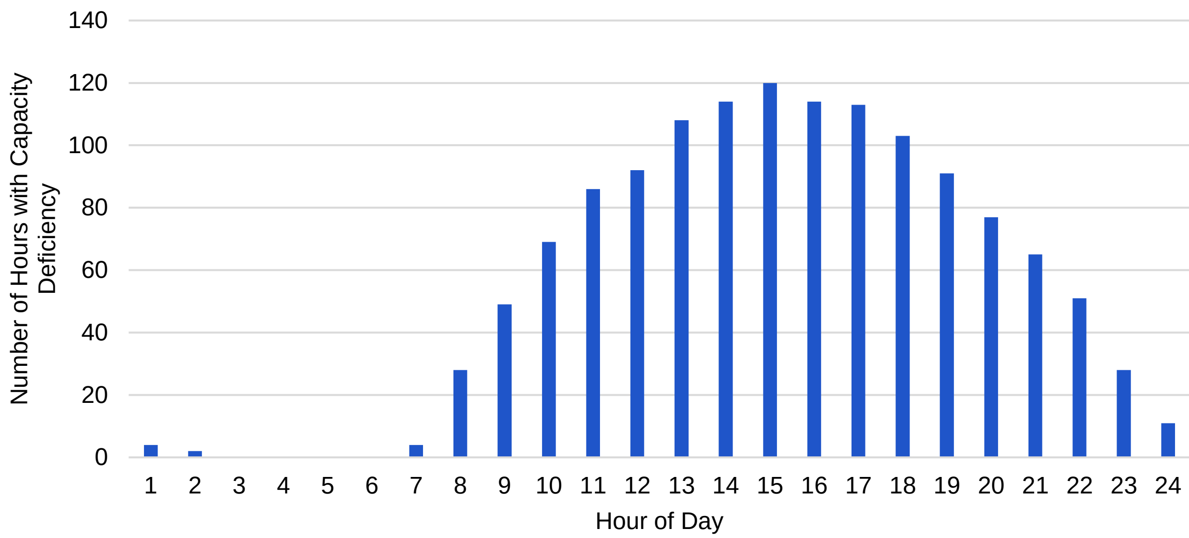
Figure D-8. Local Avoided Annual Value – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

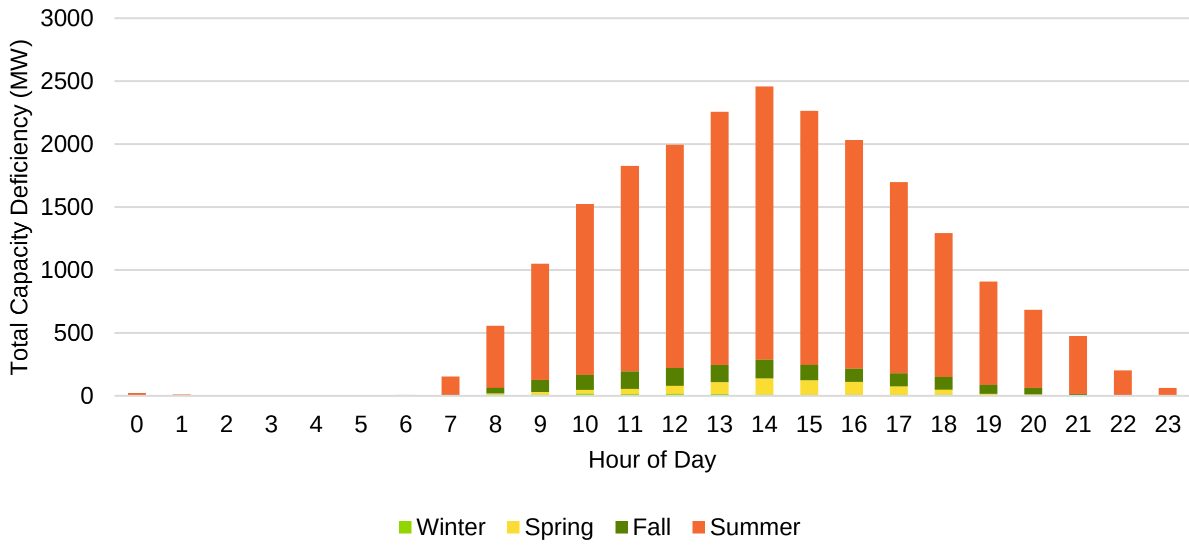
Mount Support is a historical project that had significant capacity deficiency in the region before the upgrade was performed.

Figure D-9. Number of Hours with Capacity Deficiency – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

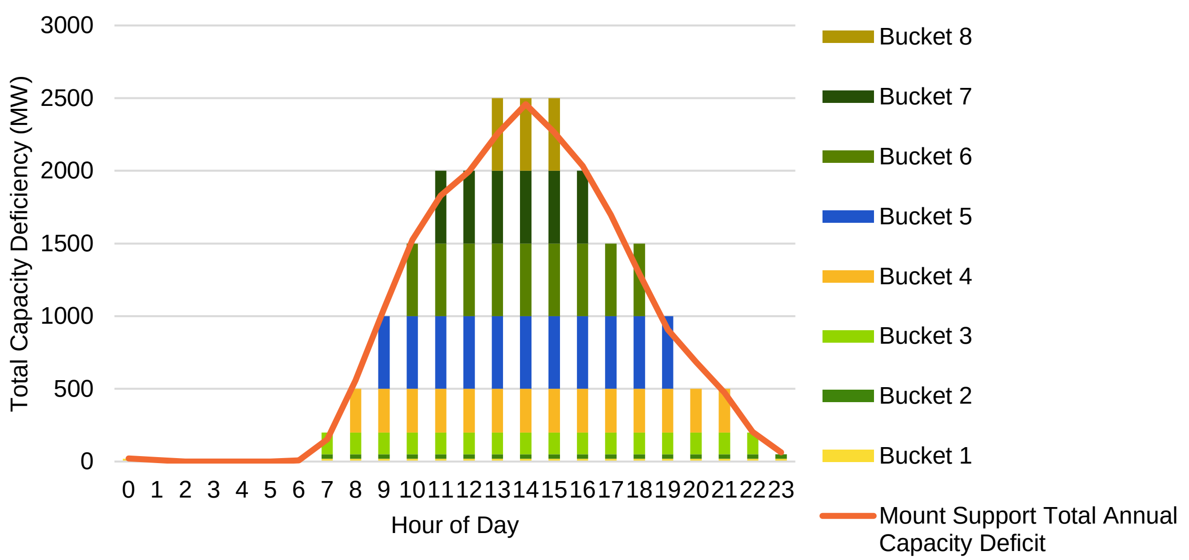
Figure D-10. Seasonal Capacity Analysis – Mount Support Substation (Bulk)



Source: Guidehouse, EDC data

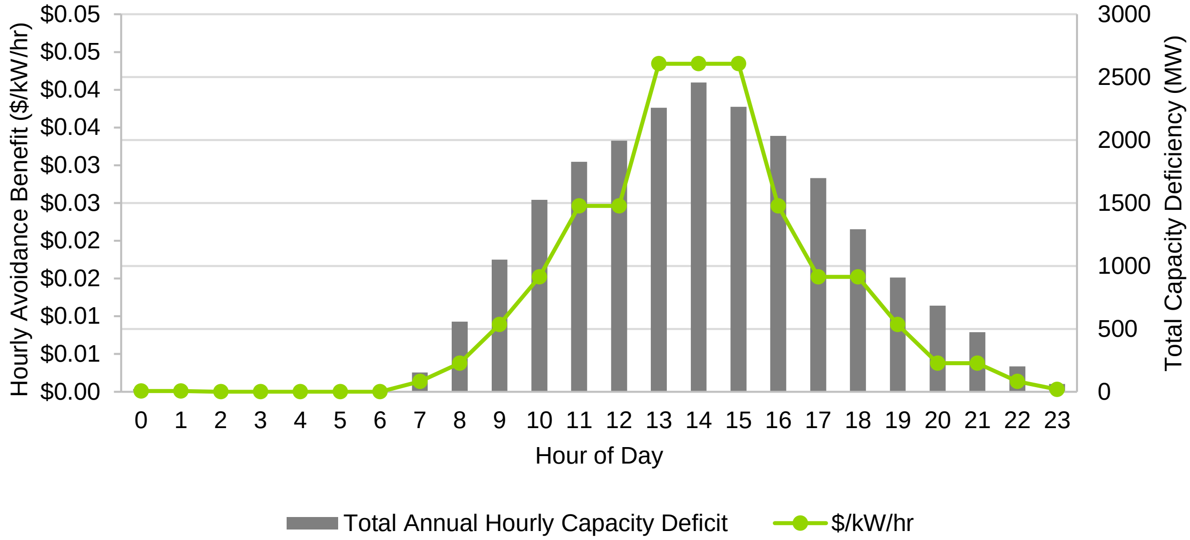
Given the number of hours of need and the large capacity deficiency for some hours, the hourly value of avoidance is small.

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)

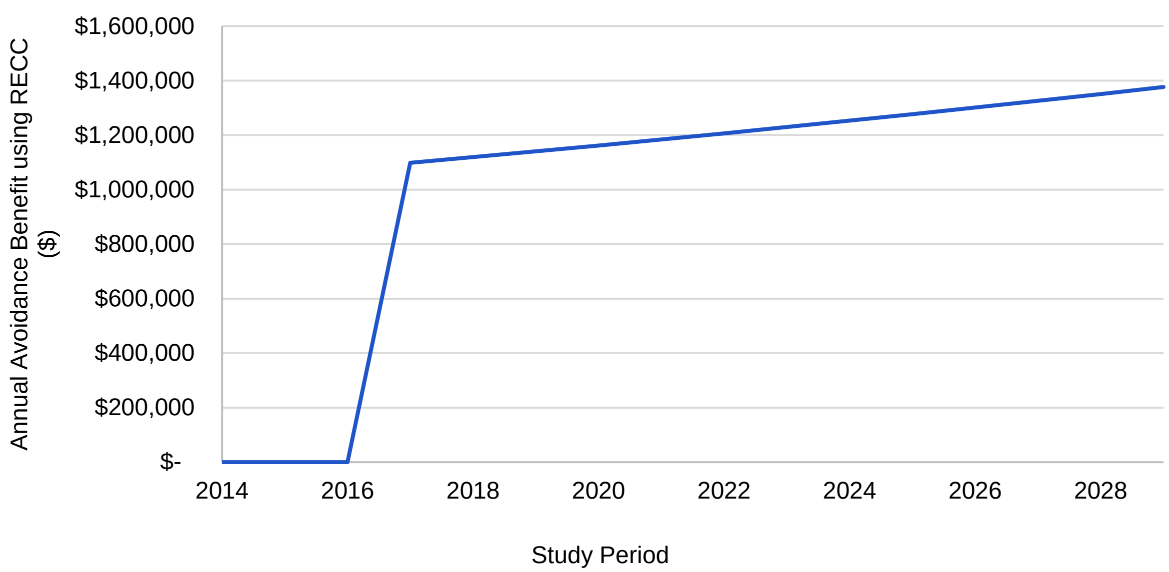


Source: Guidehouse, EDC data

Additional Example #3 - Kingston Substation Yearly and Hourly Economic Analysis (EDC: Unitil):

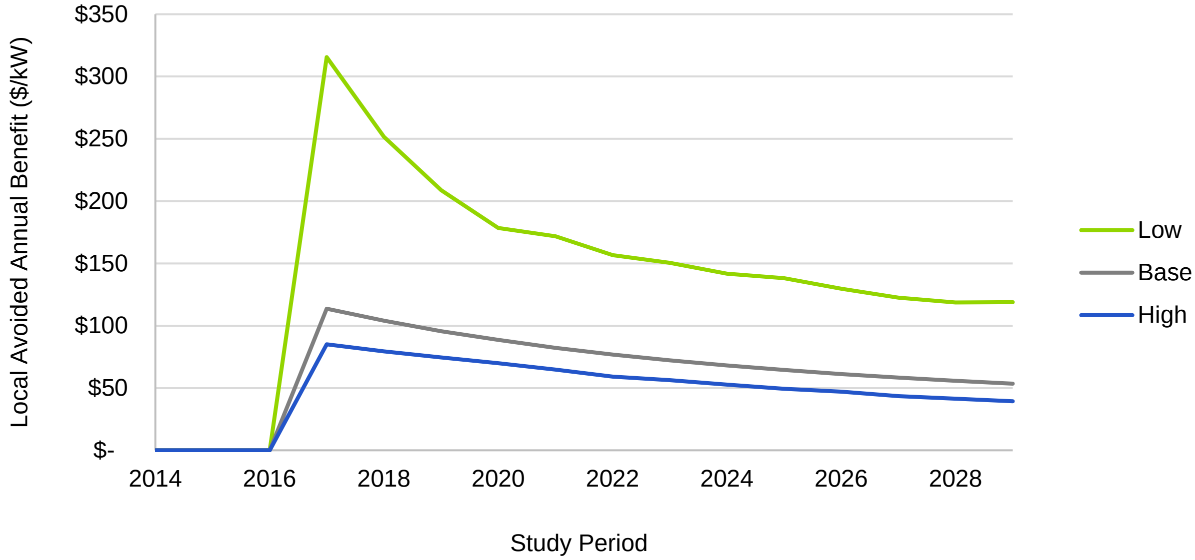
The annual avoidance value begins in 2017 and continues throughout the study period.

Figure D-13. Annual Avoidance Value – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

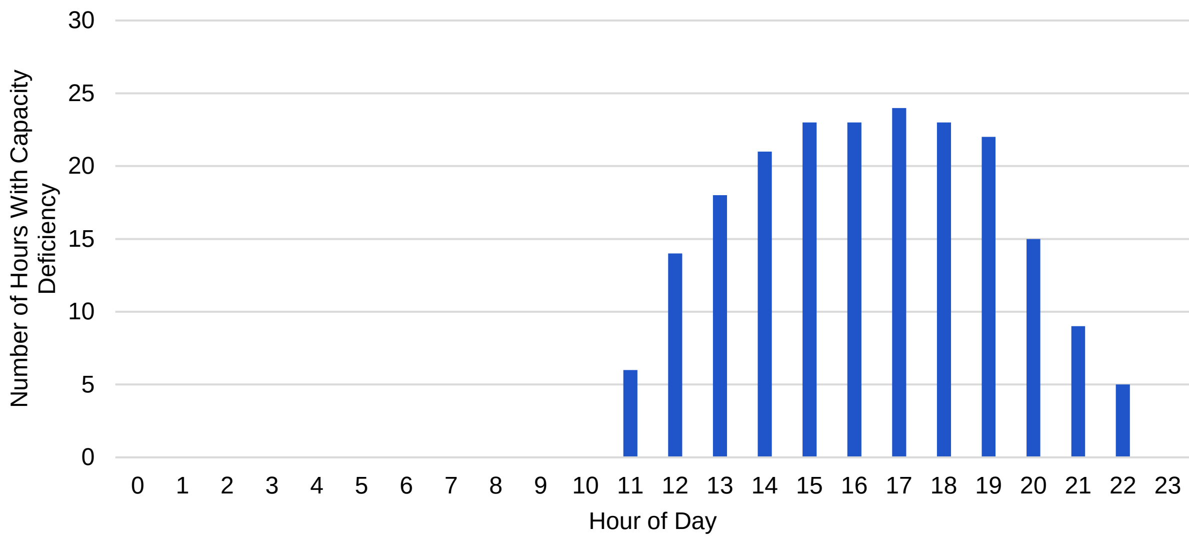
Figure D-14. Local Avoided Annual Value – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

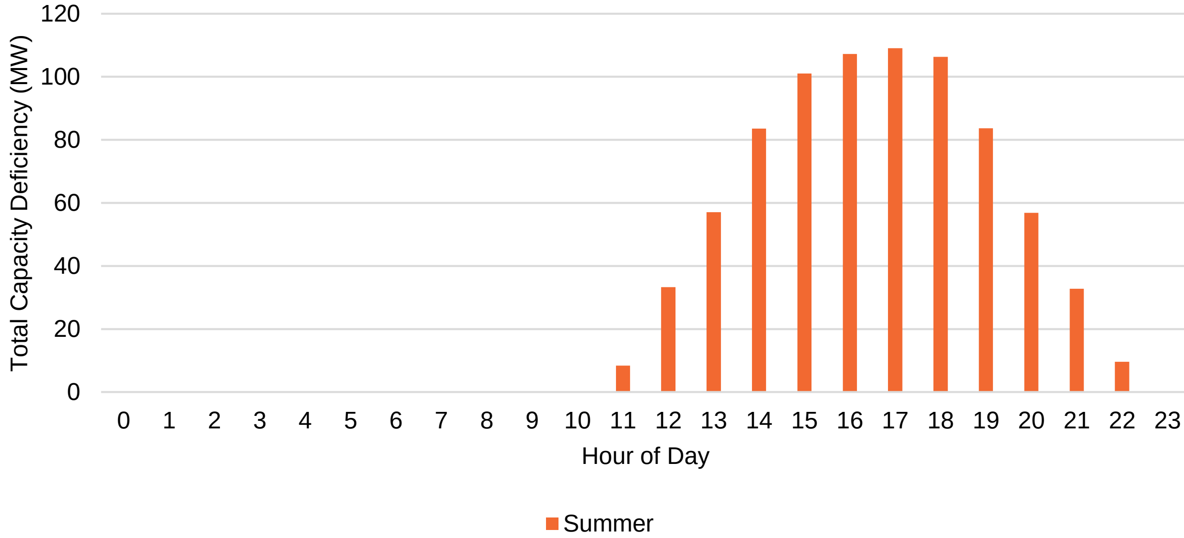
Kingston is a historical project. Based on the seacoast regional hourly load profile, this location only has periods of need during the summer season.

Figure D-15. Number of Hours with Capacity Deficiency – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

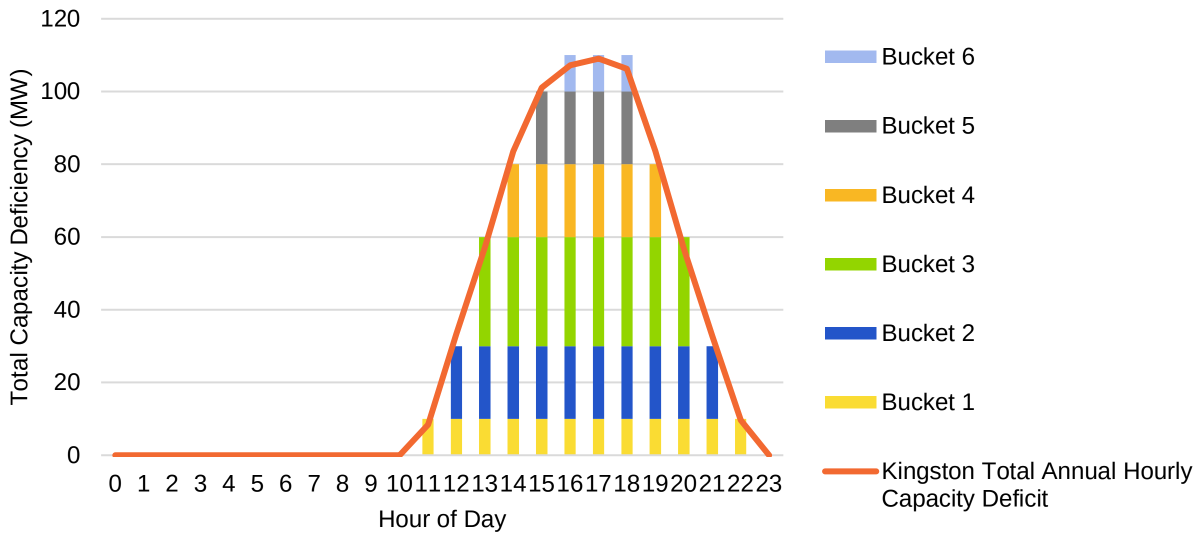
Figure D-16. Seasonal Capacity Deficiency Analysis – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

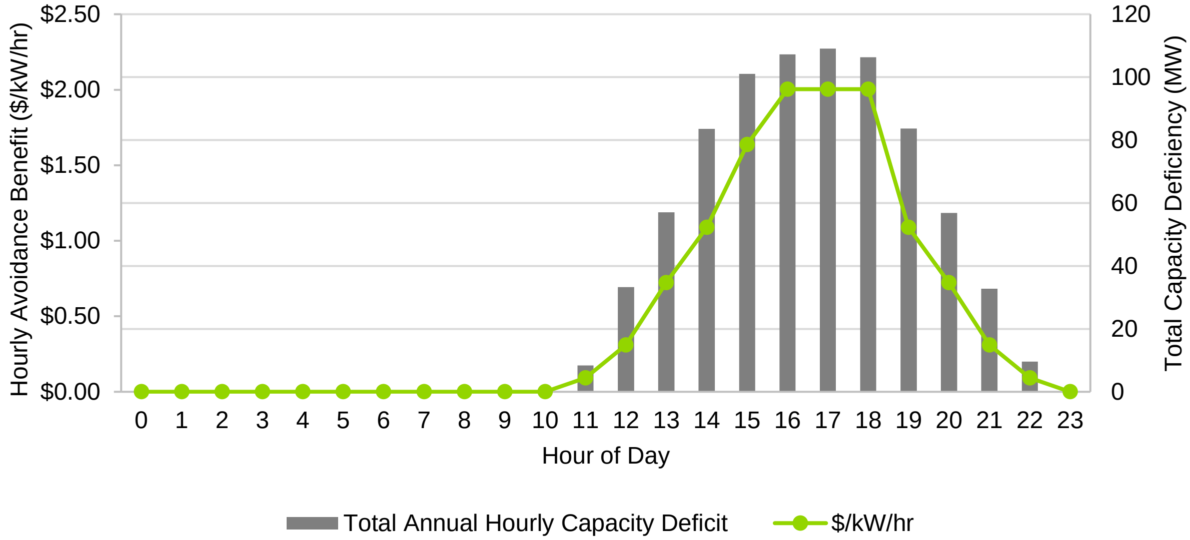
While the revenue requirement for Kingston was the highest of all the examples, the hourly value is lower than Pemi and Madbury because the capacity deficiency in terms of total MWh is higher than for Pemi and Madbury.

Figure D-17. Marginal Load Buckets (MW) – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

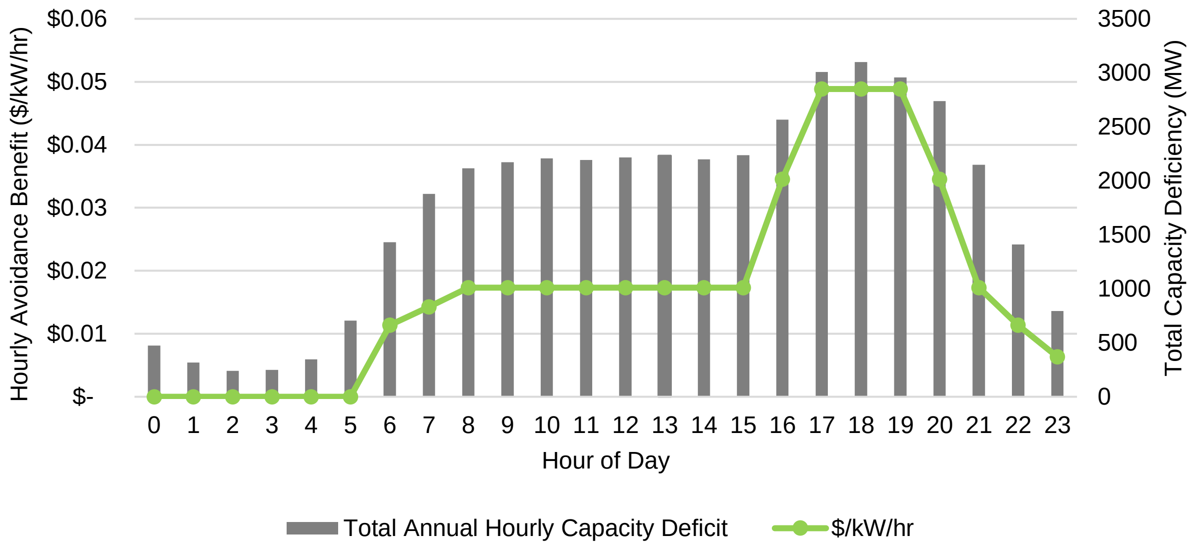
Figure D-18. Hourly Analysis for All Hours of Year – Kingston Substation (Bulk)



Source: Guidehouse, EDC data

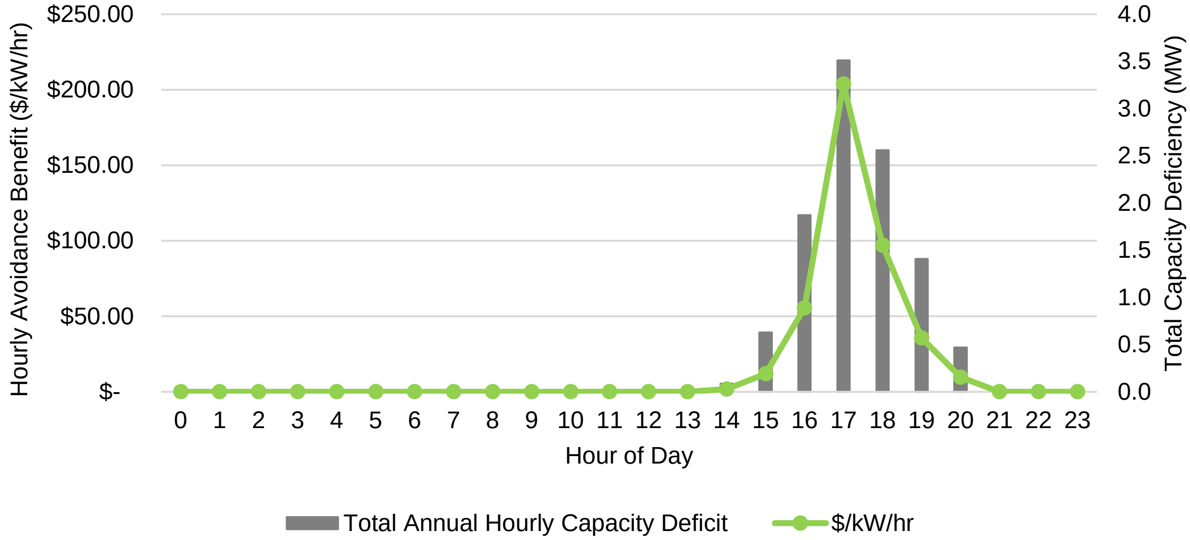
D.2 Hourly Analysis Results for Remaining 11 Sites

Figure C-19. Hourly Analysis for All Hours of Year – South Milford Substation (Bulk)



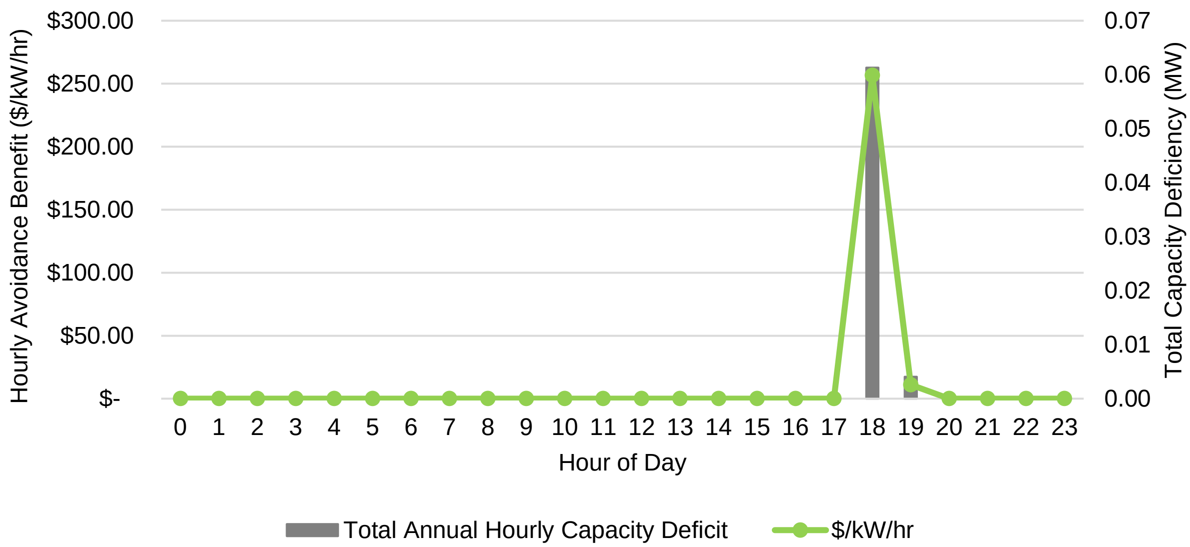
Source: Guidehouse, EDC Data

Figure C-20. Hourly Analysis for All Hours of Year – Monadnock Substation (Bulk)



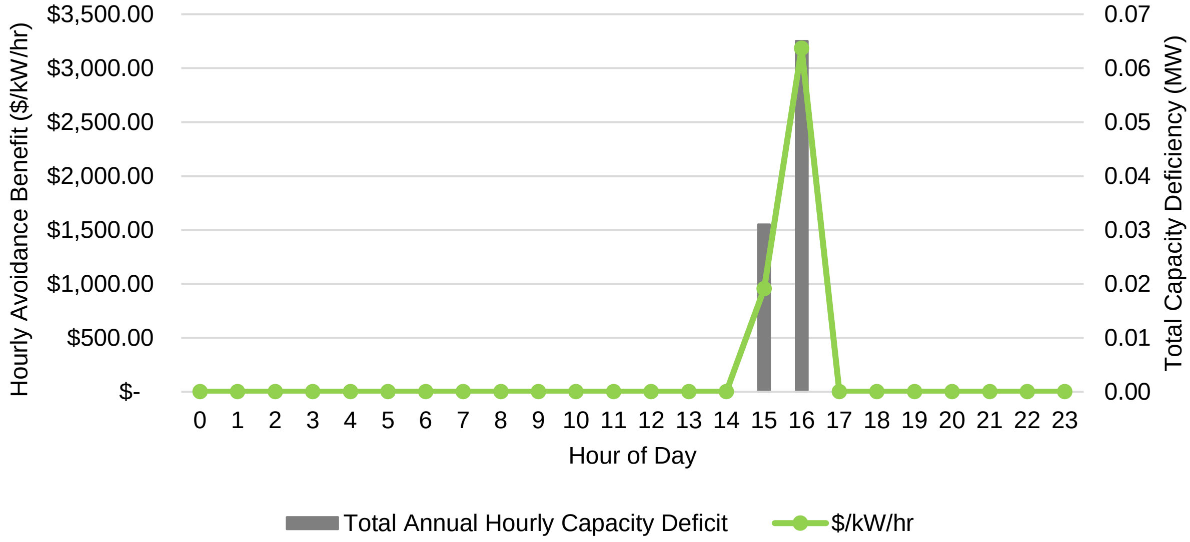
Source: Guidehouse, EDC Data

Figure C-21. Hourly Analysis for All Hours of Year – East Northwood Substation (Bulk)



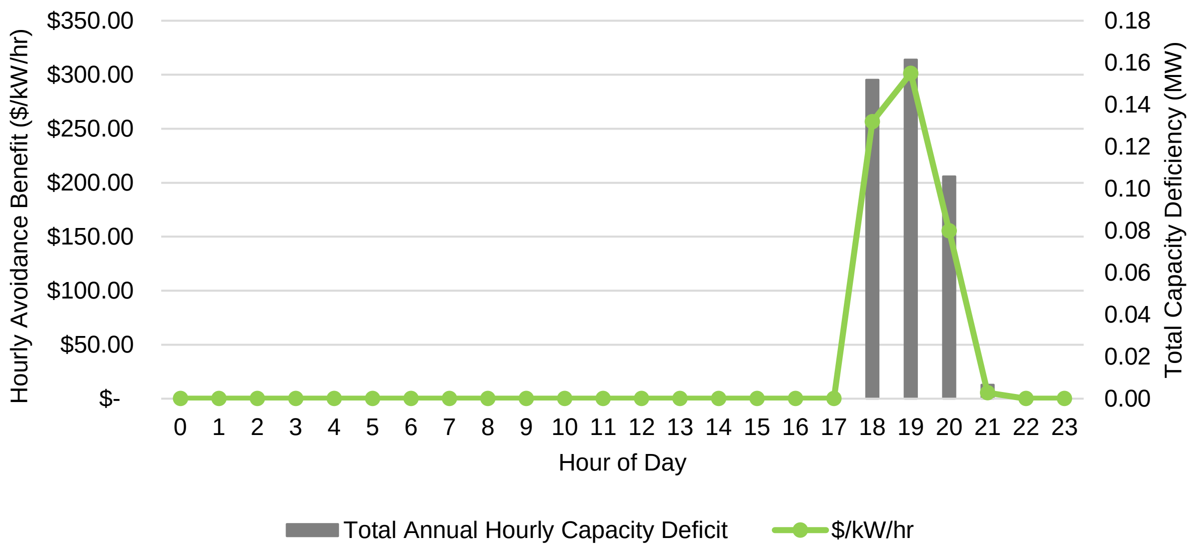
Source: Guidehouse, EDC Data

Figure C-22. Hourly Analysis for All Hours of Year – Rye Substation (Non-Bulk)



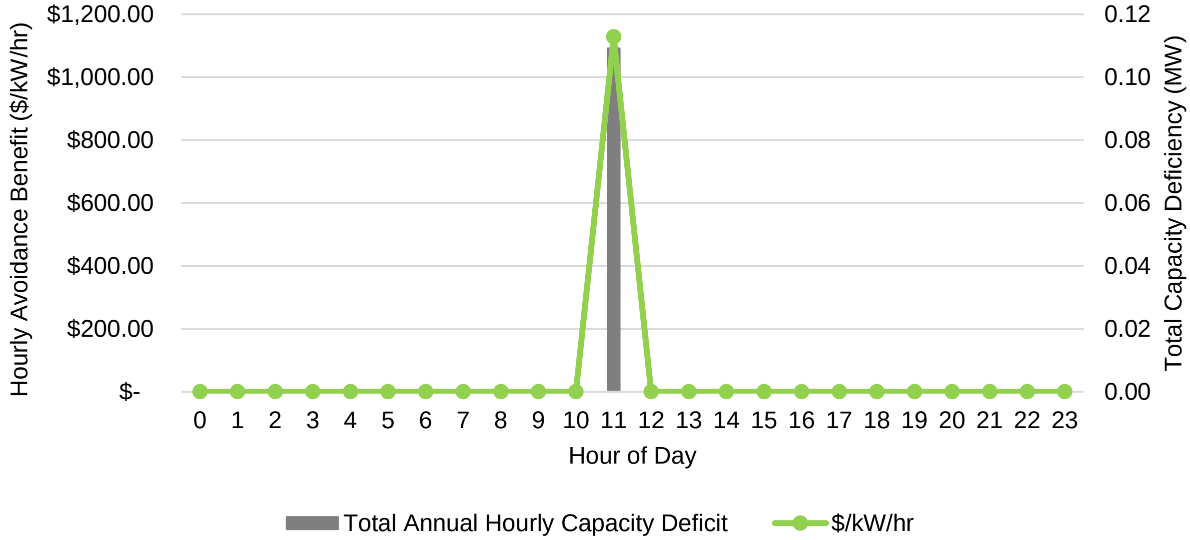
Source: Guidehouse, EDC Data

Figure C-23. Hourly Analysis for All Hours of Year – Bristol Substation (Non-Bulk)



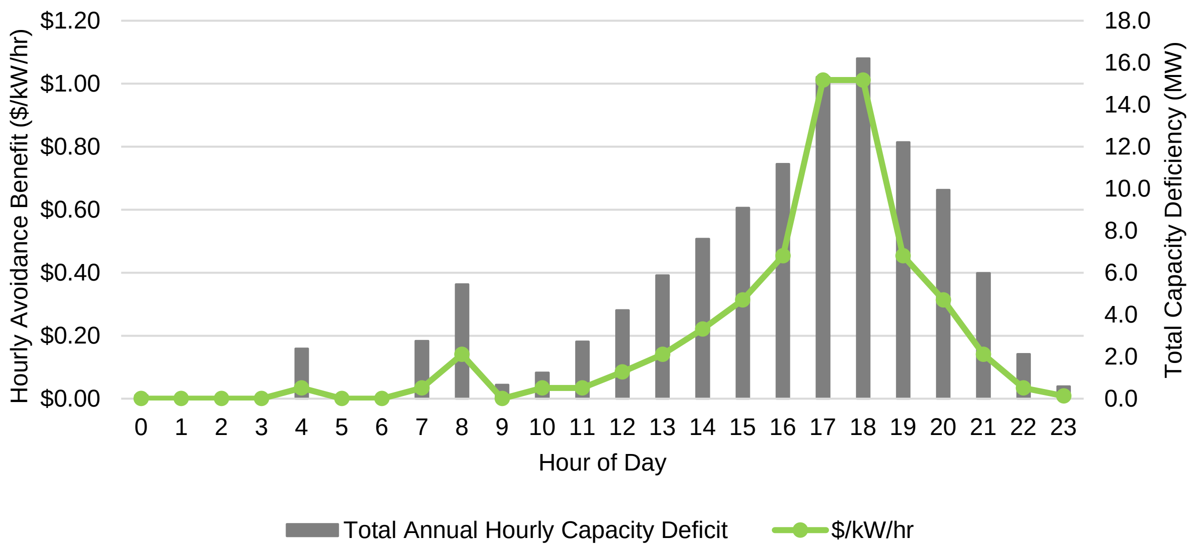
Source: Guidehouse, EDC Data

Figure C-24. Hourly Analysis for All Hours of Year – North Keene Circuit (12.47 kV)



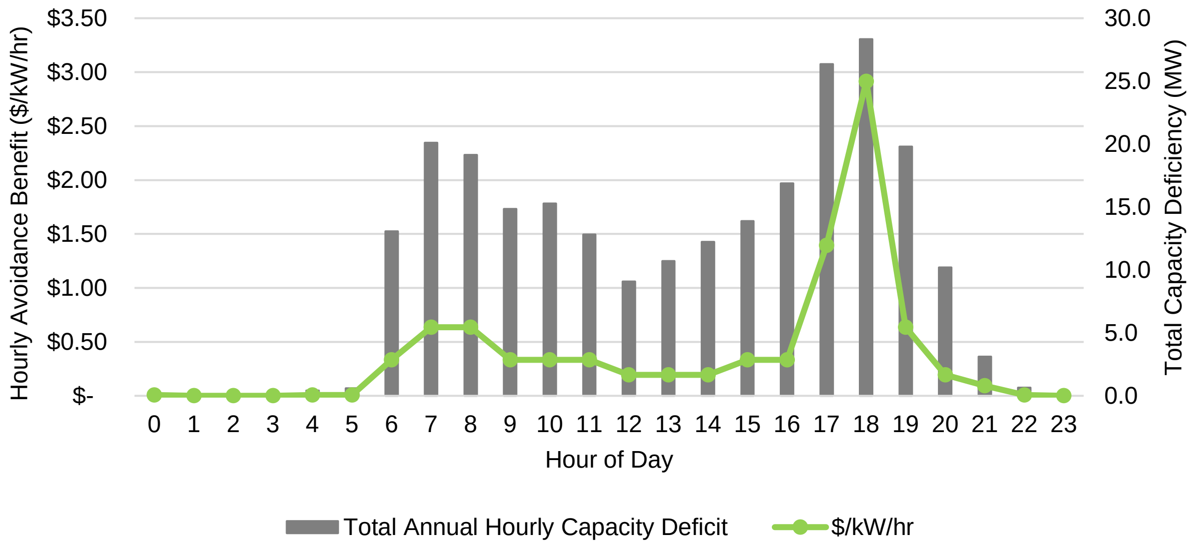
Source: Guidehouse, EDC data

Figure C-25. Hourly Analysis for All Hours of Year – Londonderry Circuit (34.5 kV)



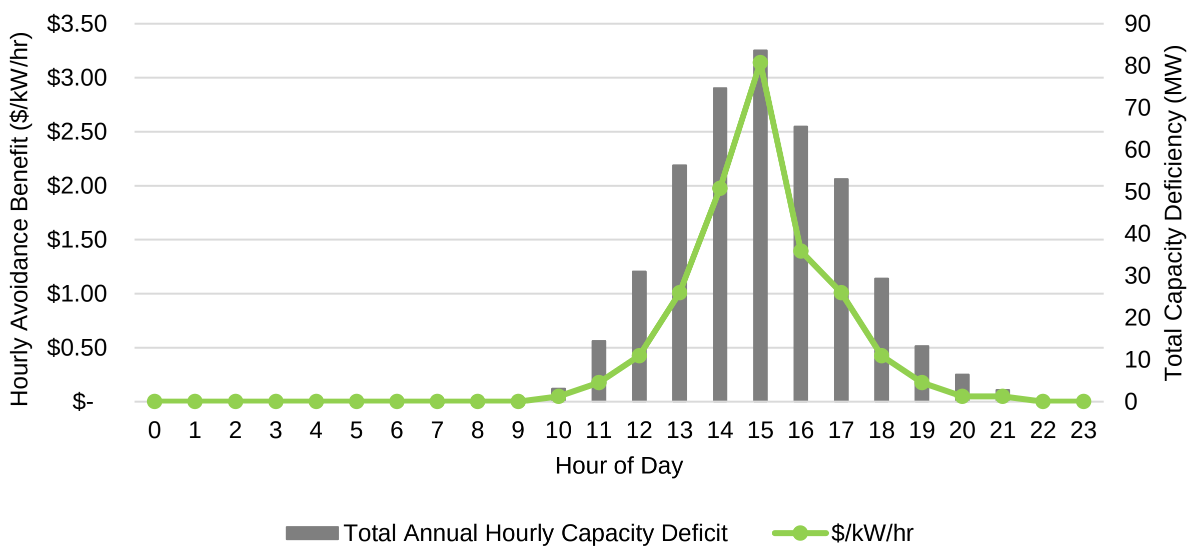
Source: Guidehouse, EDC Data

Figure C-26. Hourly Analysis for All Hours of Year – Vilas Bridge Substation (Non-Bulk)



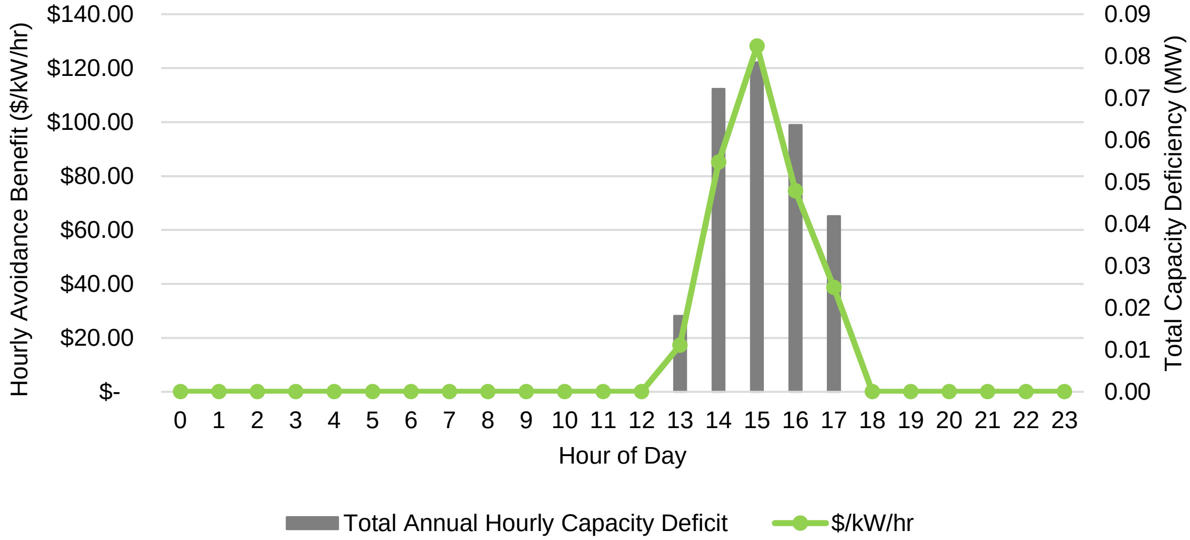
Source: Guidehouse, EDC Data

Figure C-27. Hourly Analysis for All Hours of Year – Golden Rock Substation (Bulk)



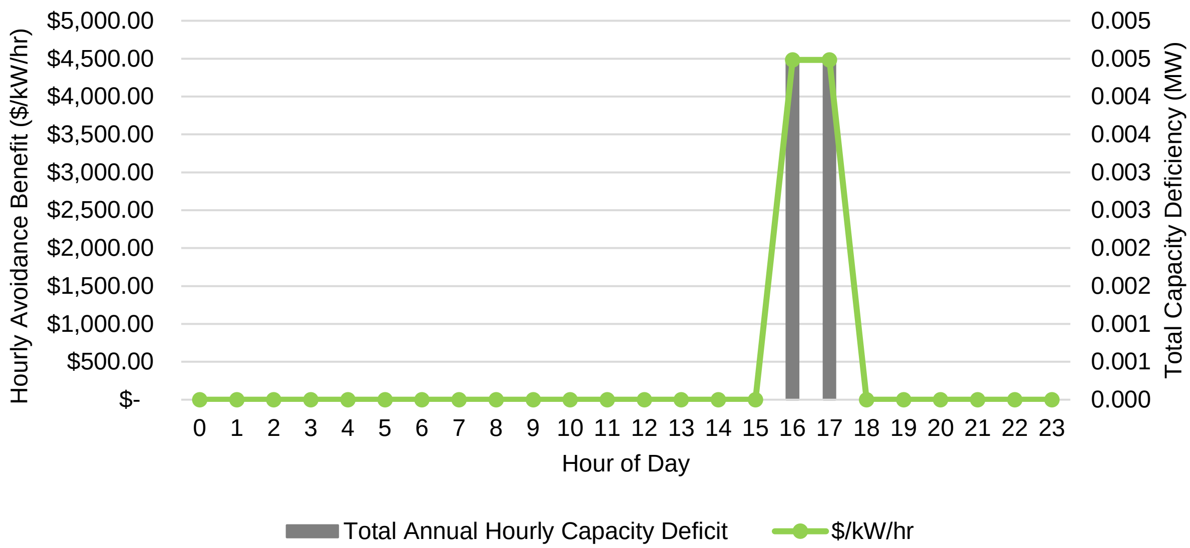
Source: Guidehouse, EDC Data

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

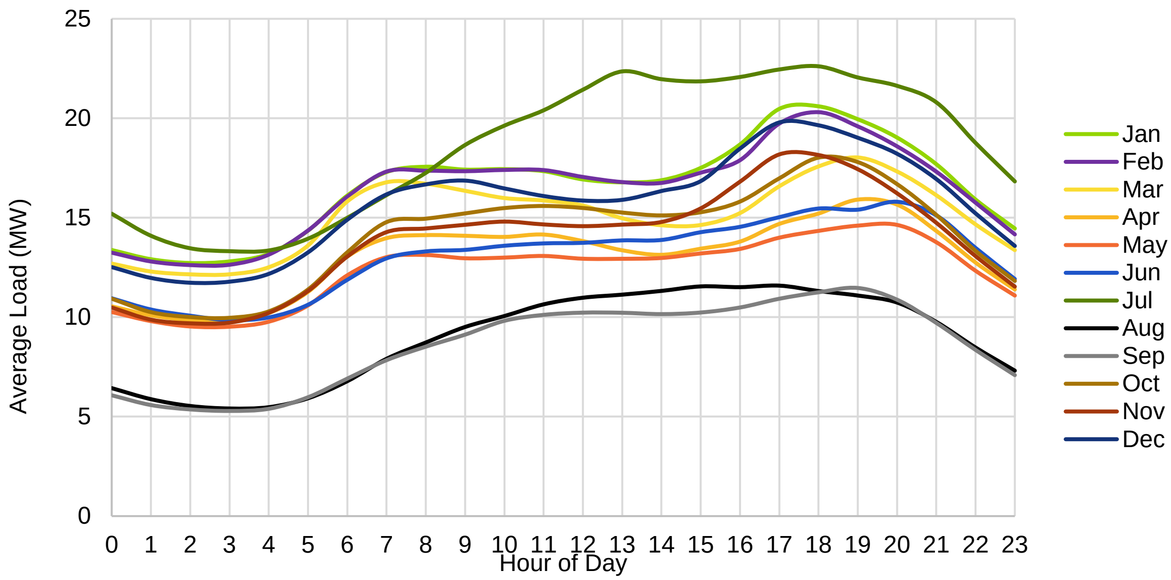
Appendix E. Additional Examples of Load and DG Output Profiles

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)

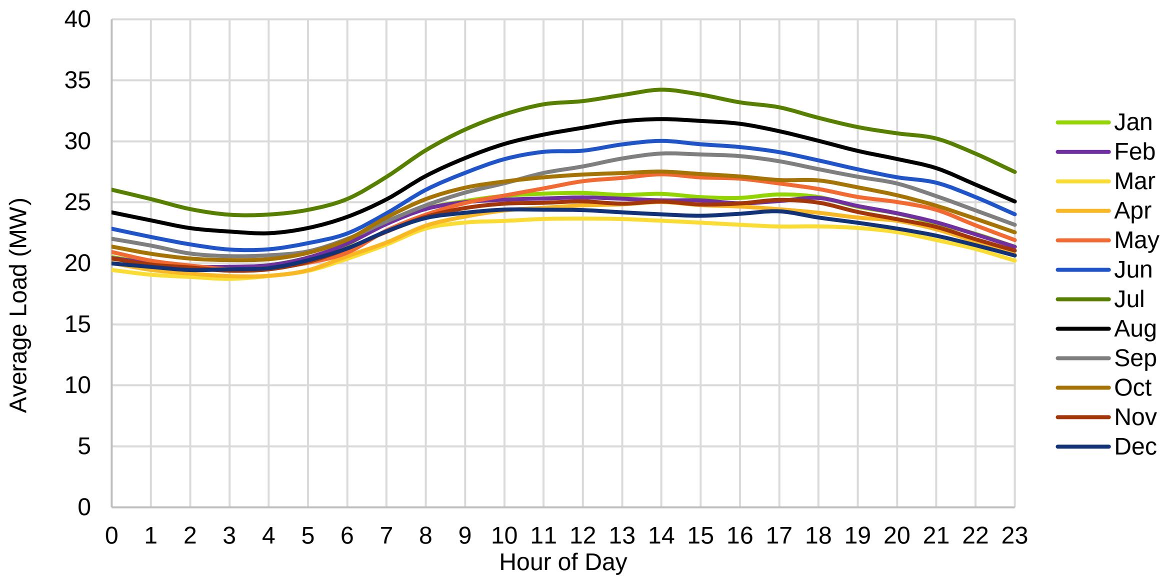


Source: Guidehouse, EDC data

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)

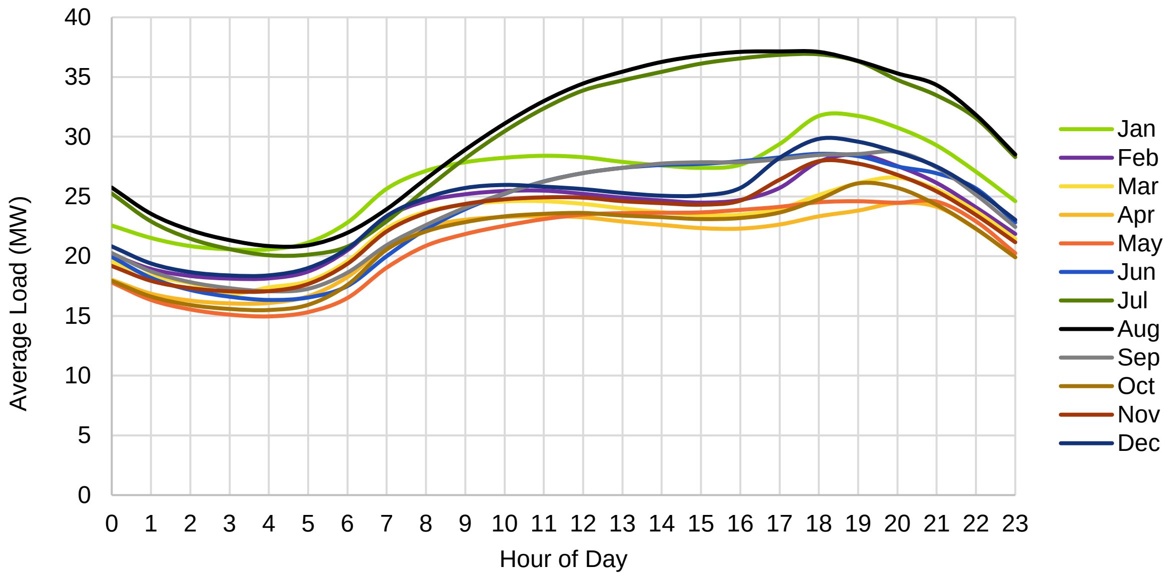


Source: Guidehouse, EDC data

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

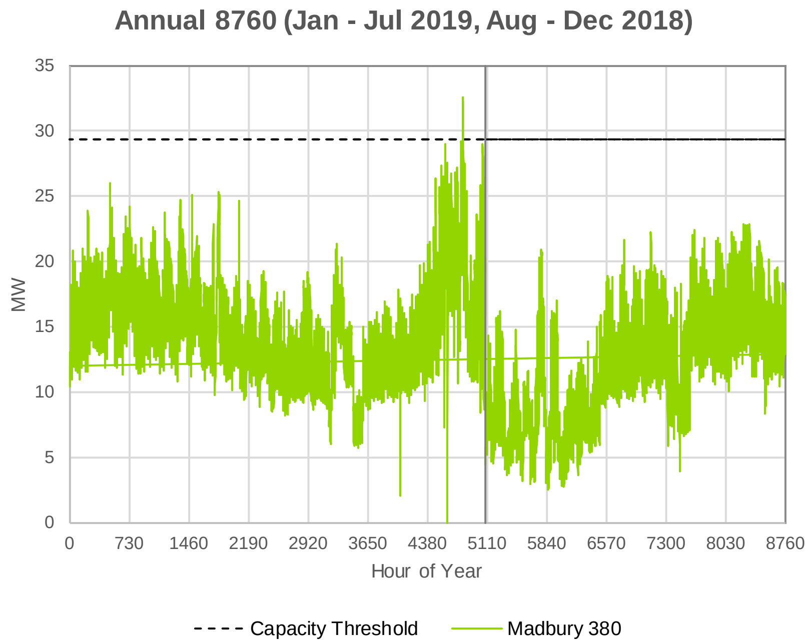
Madbury ROW Circuit (34.5 kV) DG Analysis Results

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)

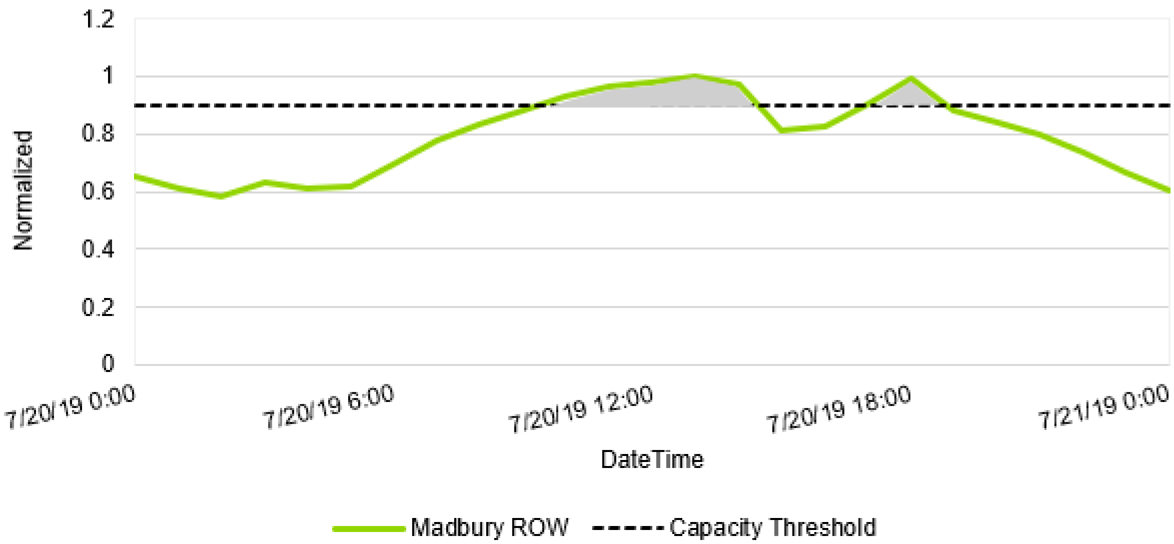
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Madbury ROW Circuit (34.5 kV)	Eastern	32.58	7/20/19 13:00	3.23

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

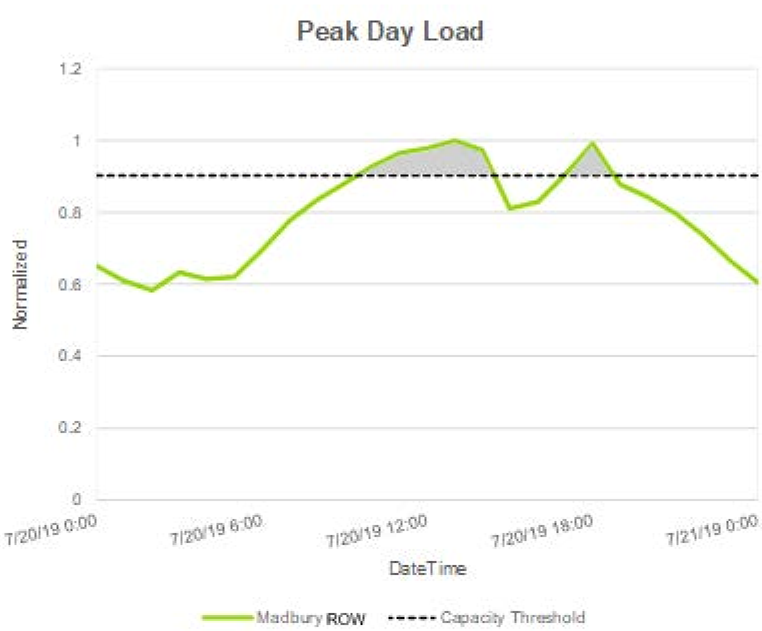
Figure E-5. Summer Peak Day Load – Madbury ROW Circuit (34.5 kV)



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)

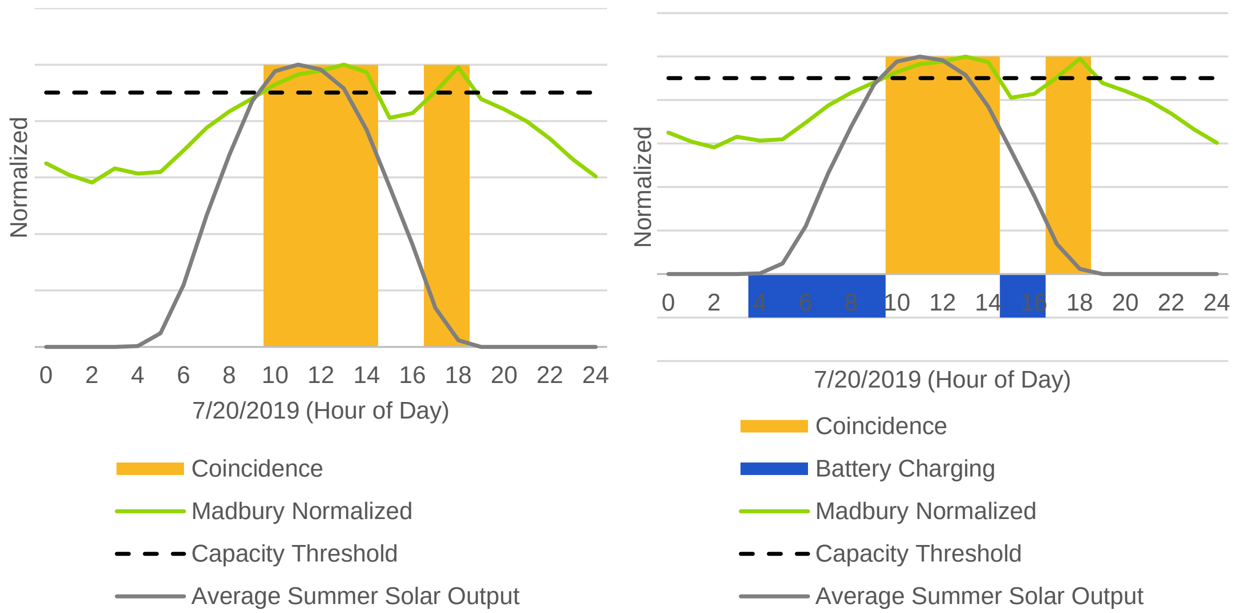


Source: Guidehouse, EDC data

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)

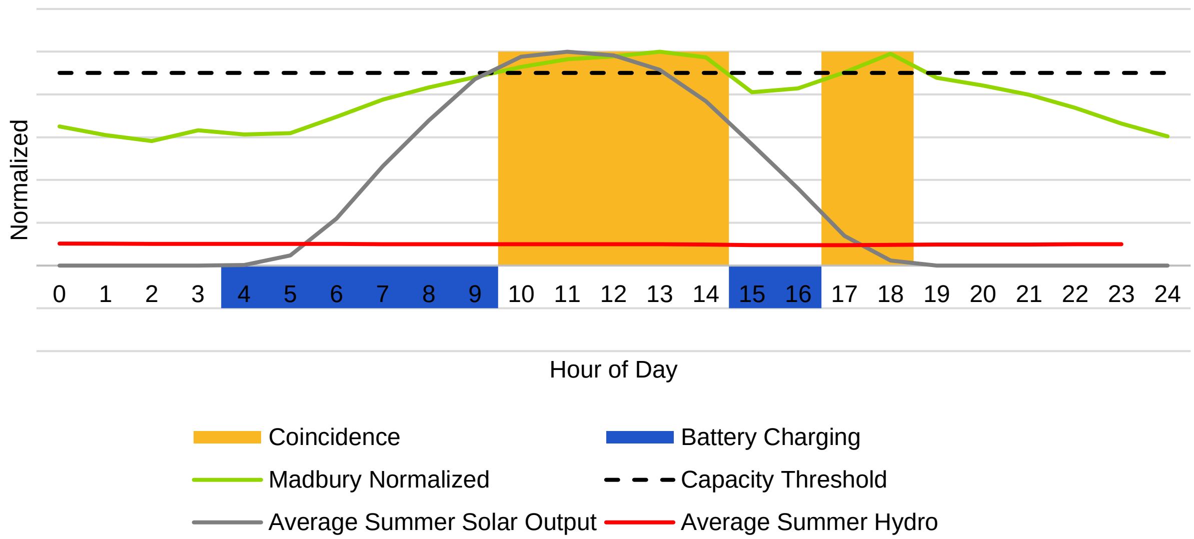


Source: Guidehouse, EDC data

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)



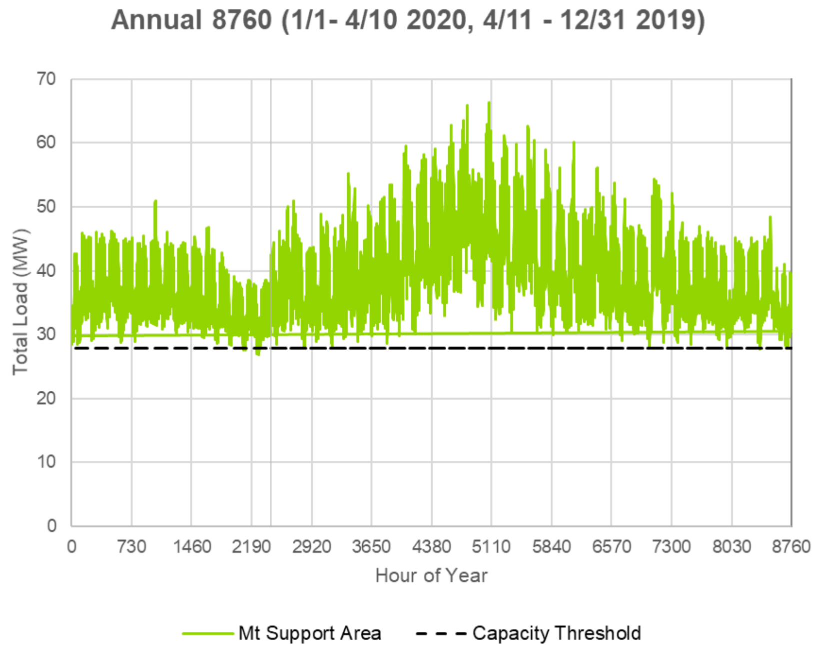
Source: Guidehouse, EDC data

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)

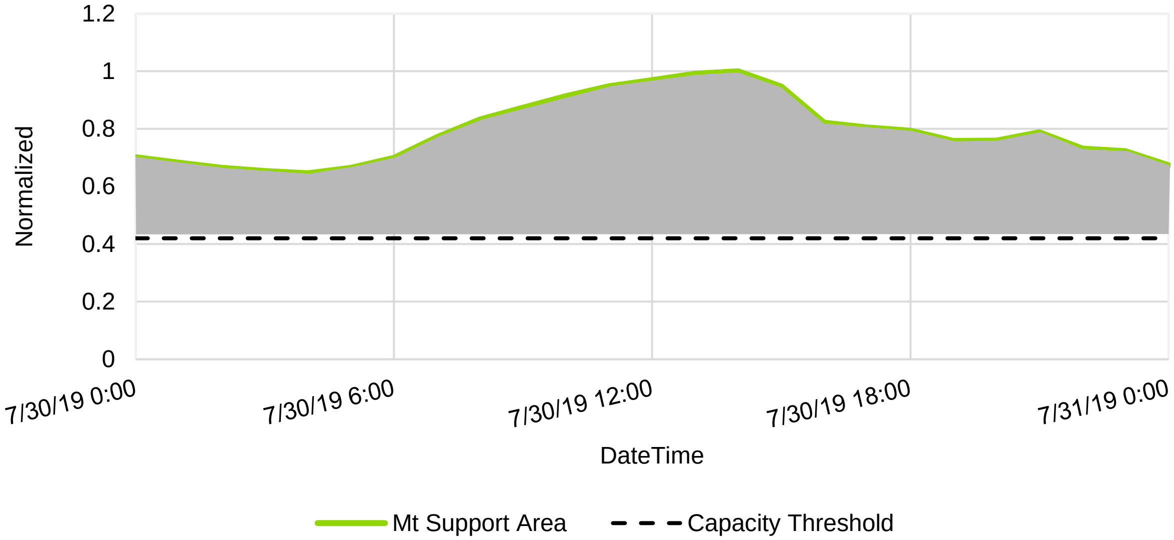
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Mount Support Substation (Bulk)	Lebanon	66.4	7/30/19 14:00	Prior 2014

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)

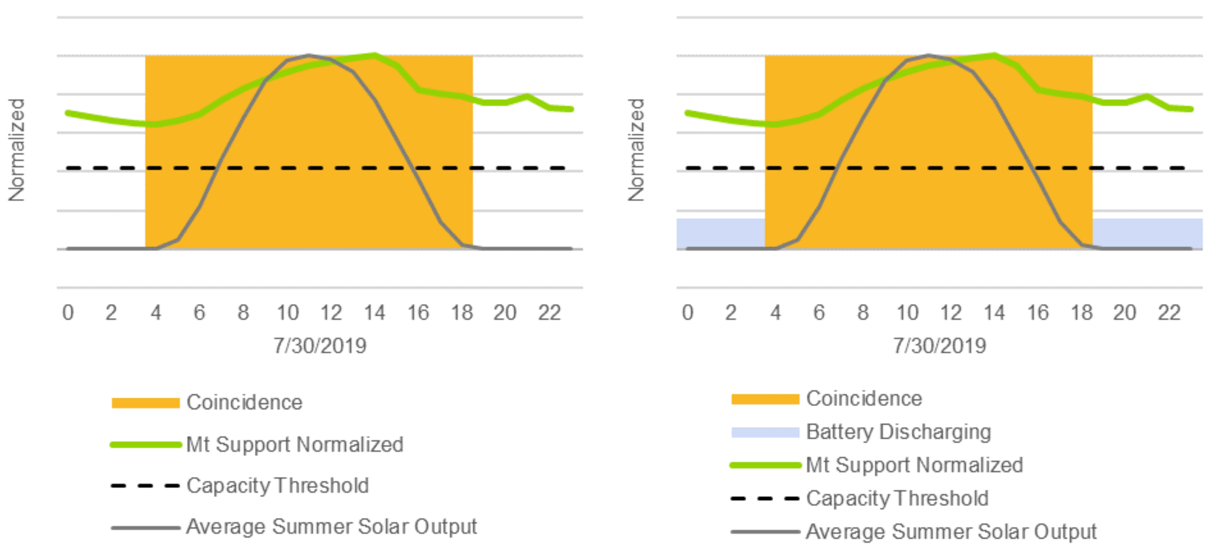


Source: Guidehouse, EDC data

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)

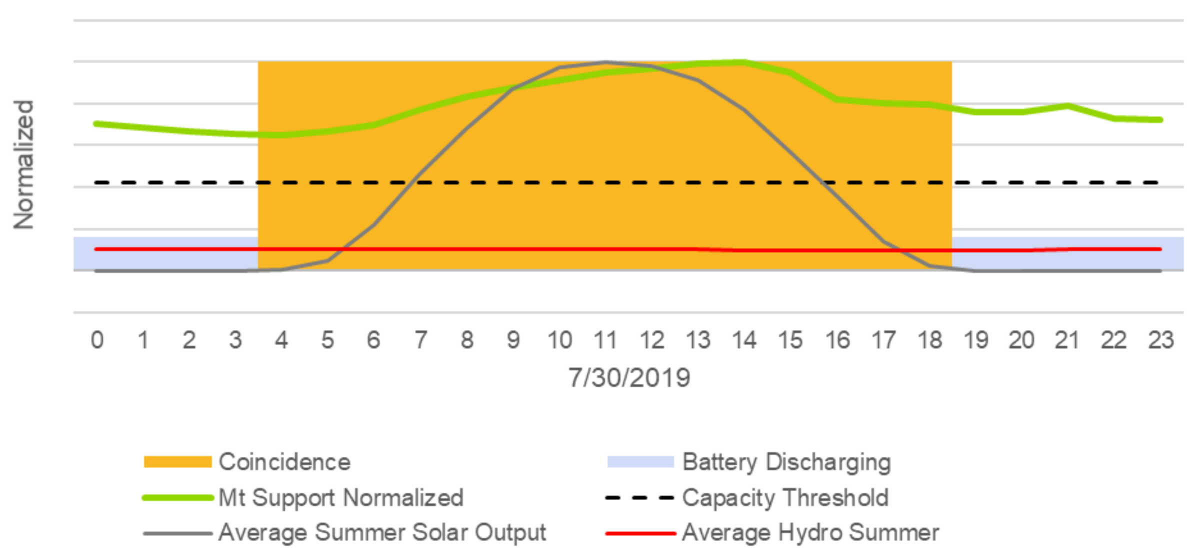


Source: Guidehouse, EDC data

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)



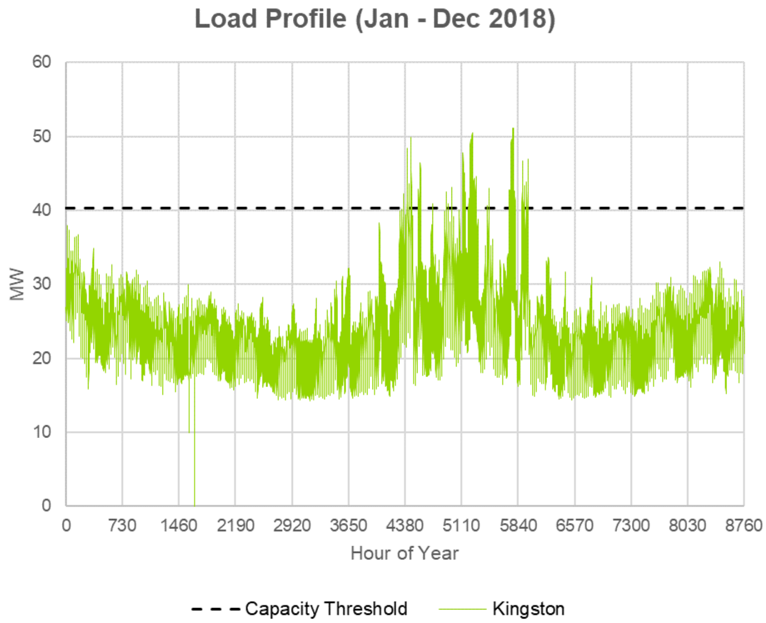
Source: Guidehouse, EDC data

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)

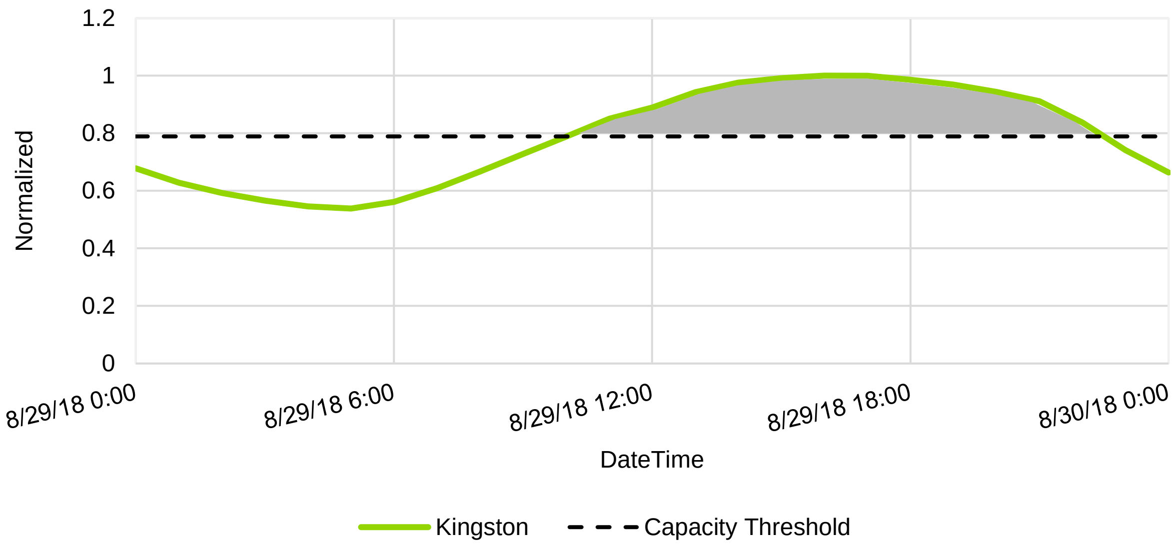
Location	Region	Peak (MW)	Time of Peak	First Year Deficit (MW)
Kingston Substation (Bulk)	Seacoast	51	8/29/18 17:00	Prior 2014

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)

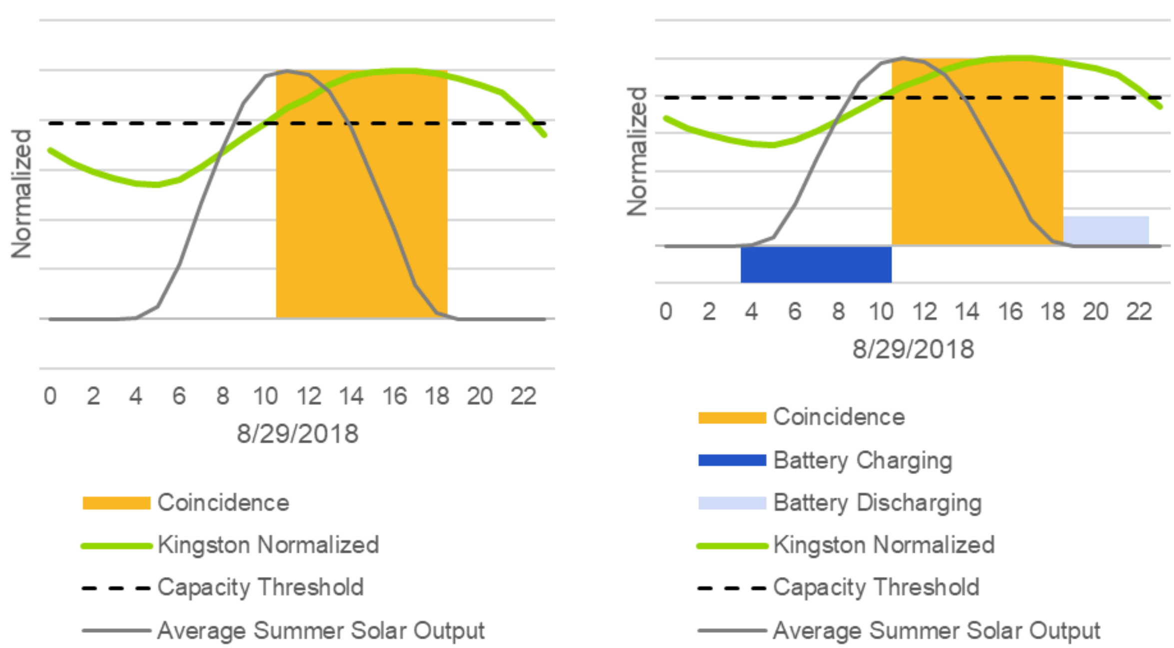


Source: Guidehouse, EDC data

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)

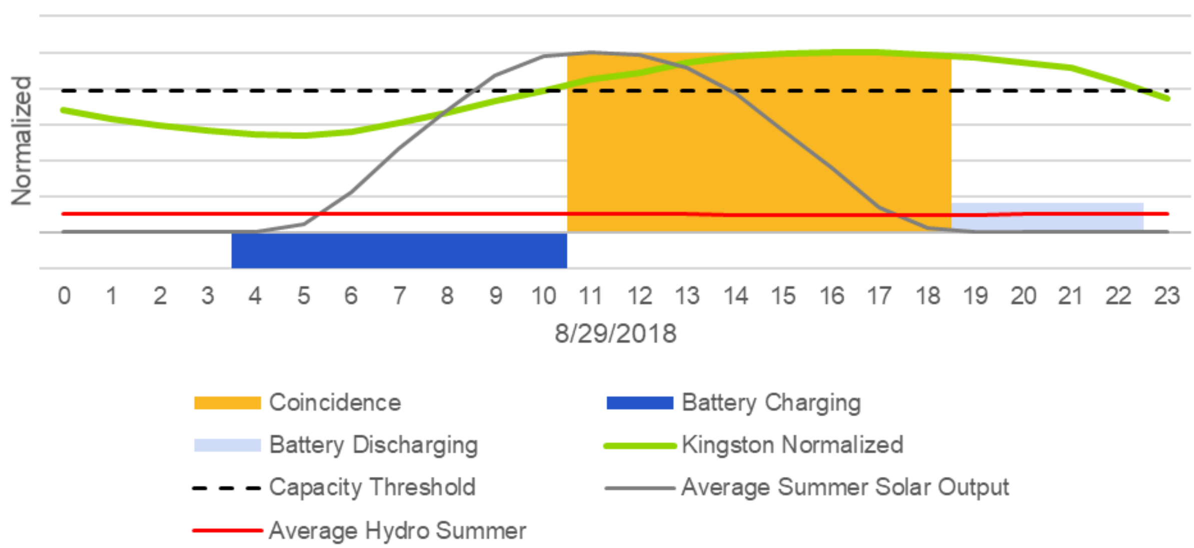


Source: Guidehouse, EDC data

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

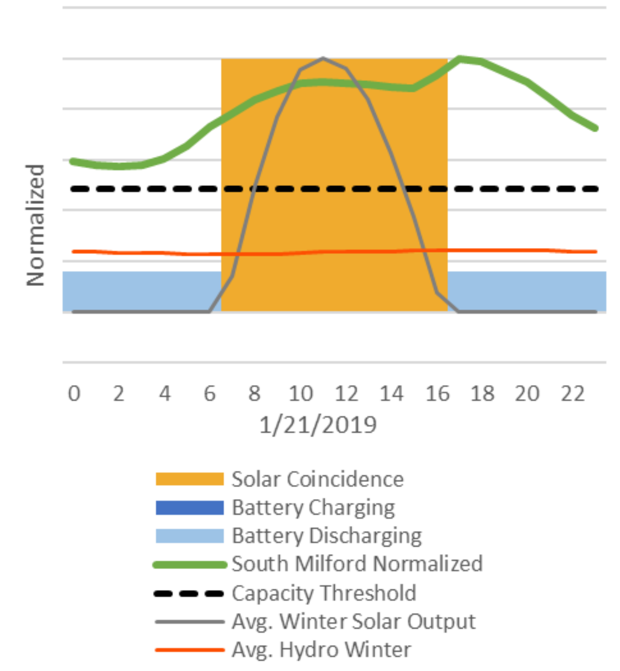
Figure E-16. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Kingston Substation (Bulk)

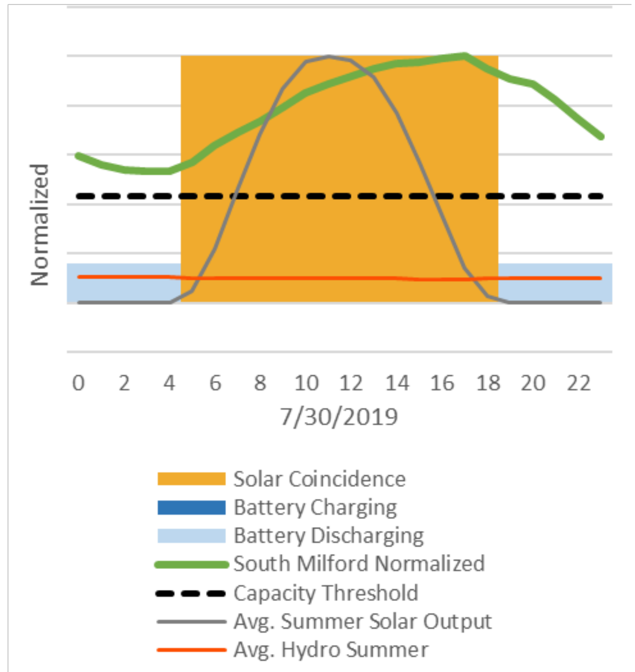


Source: Guidehouse, EDC data

E.3 DG Production Profiles for Remaining 11 Sites

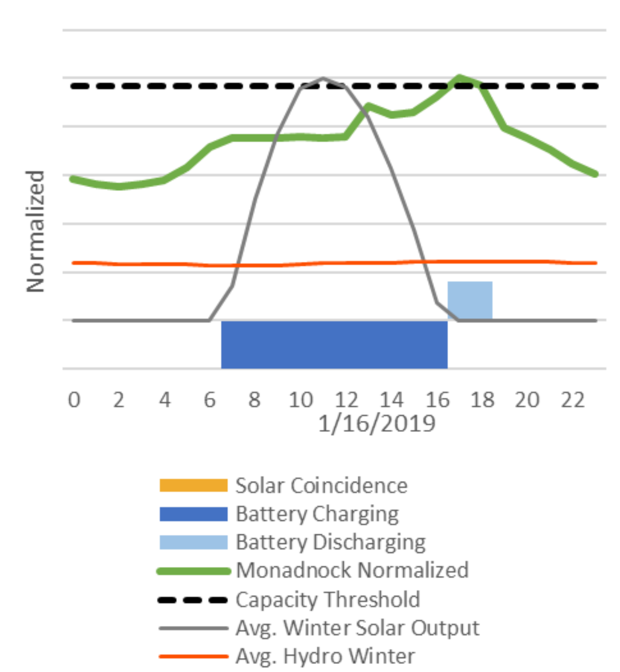
Figure E-17. Solar Coincidence and Solar plus Storage plus Hydro Analysis – South Milford

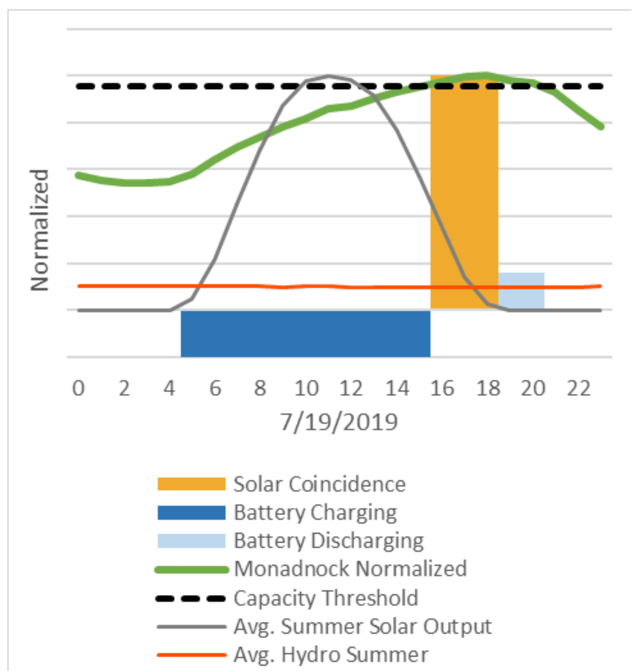




Source: Guidehouse, EDC data

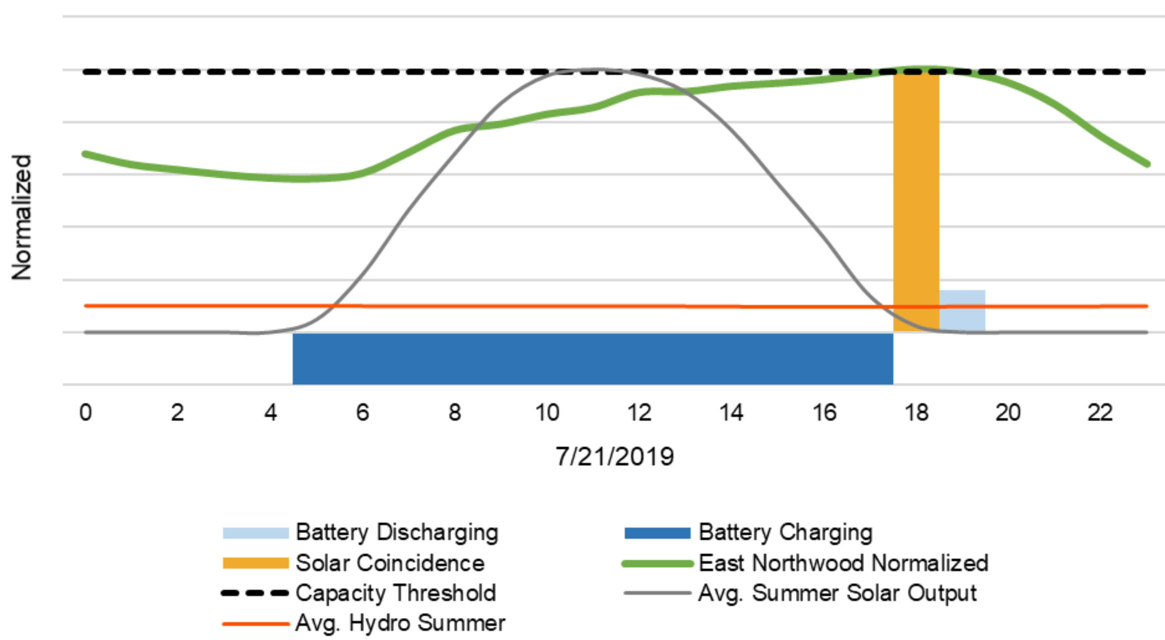
Figure E-18. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Monadnock





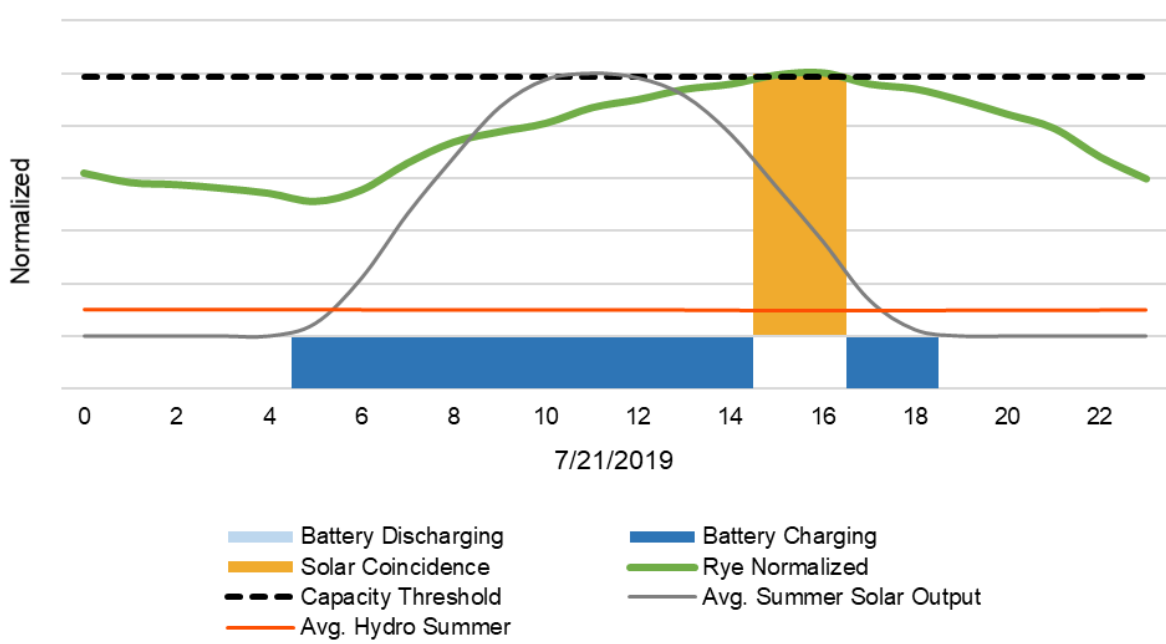
Source: Guidehouse, EDC data

Figure E-19. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – East Northwood (Non-Bulk)



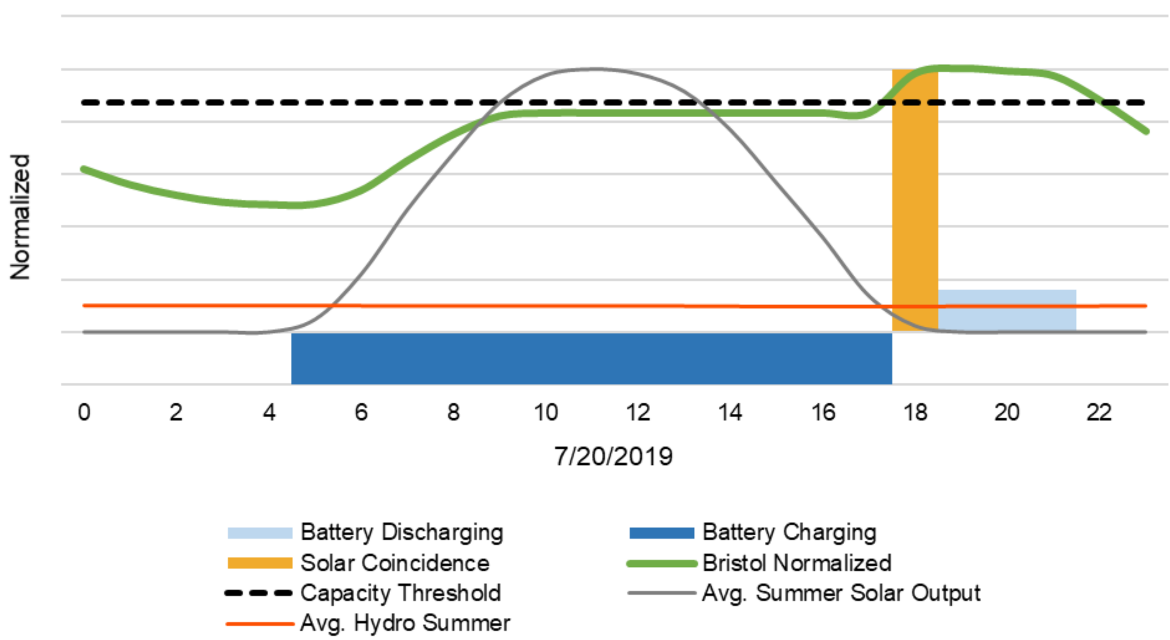
Source: Guidehouse, EDC data

Figure E-20. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Rye (Non-Bulk)



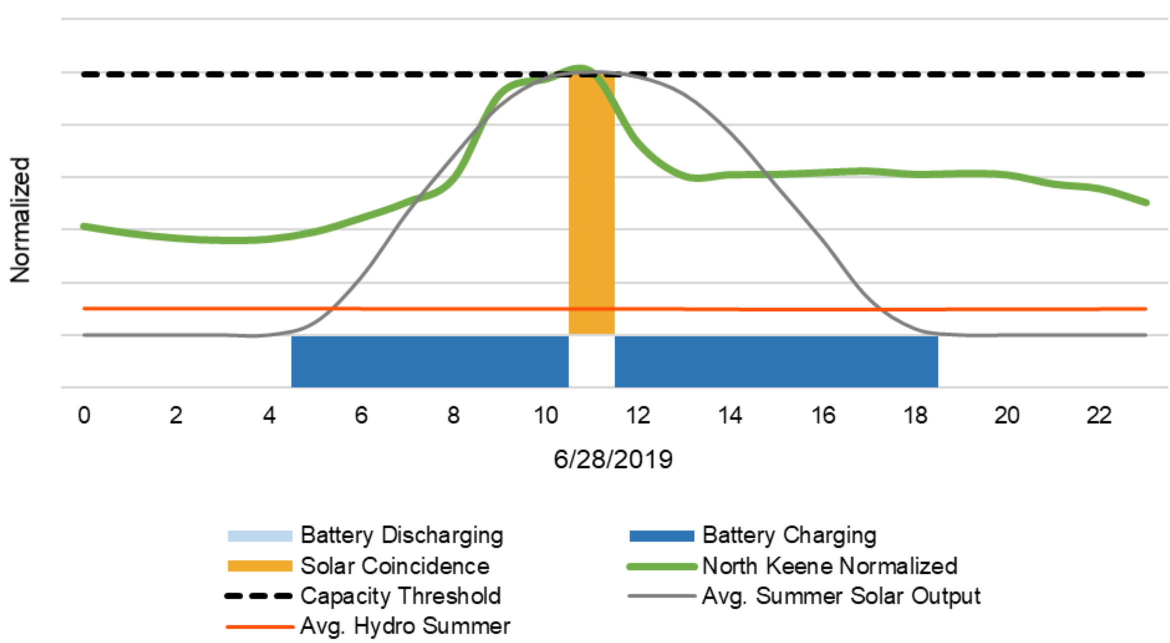
Source: Guidehouse, EDC data

Figure E-21. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Bristol (Non-Bulk)



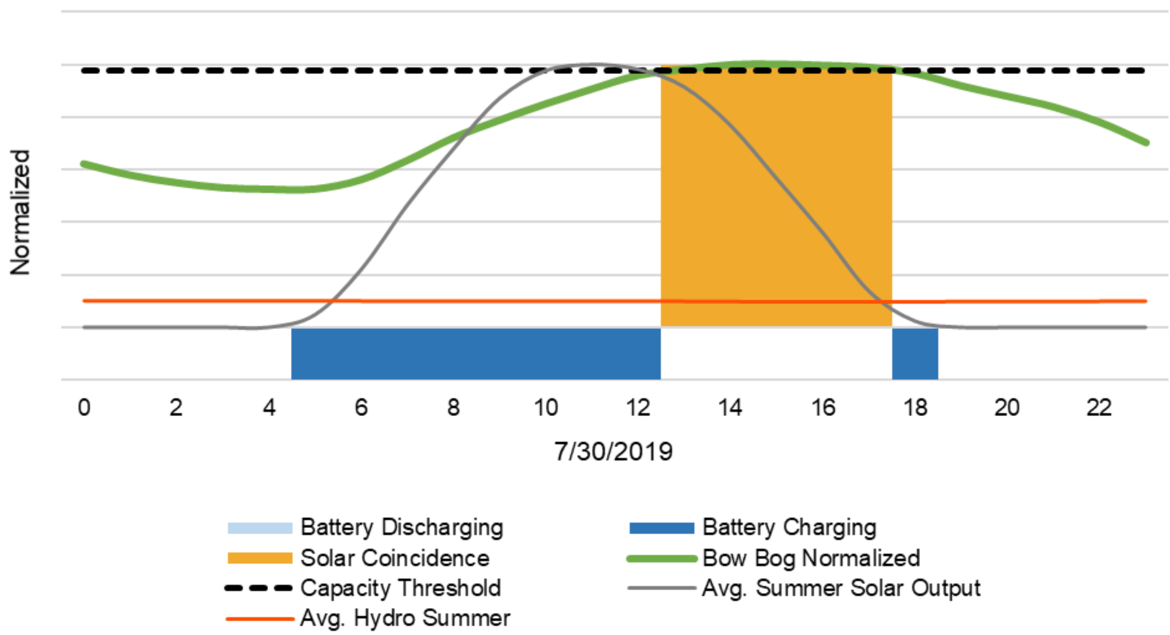
Source: Guidehouse, EDC data

Figure E-22. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – North Keene (12.47 kV)



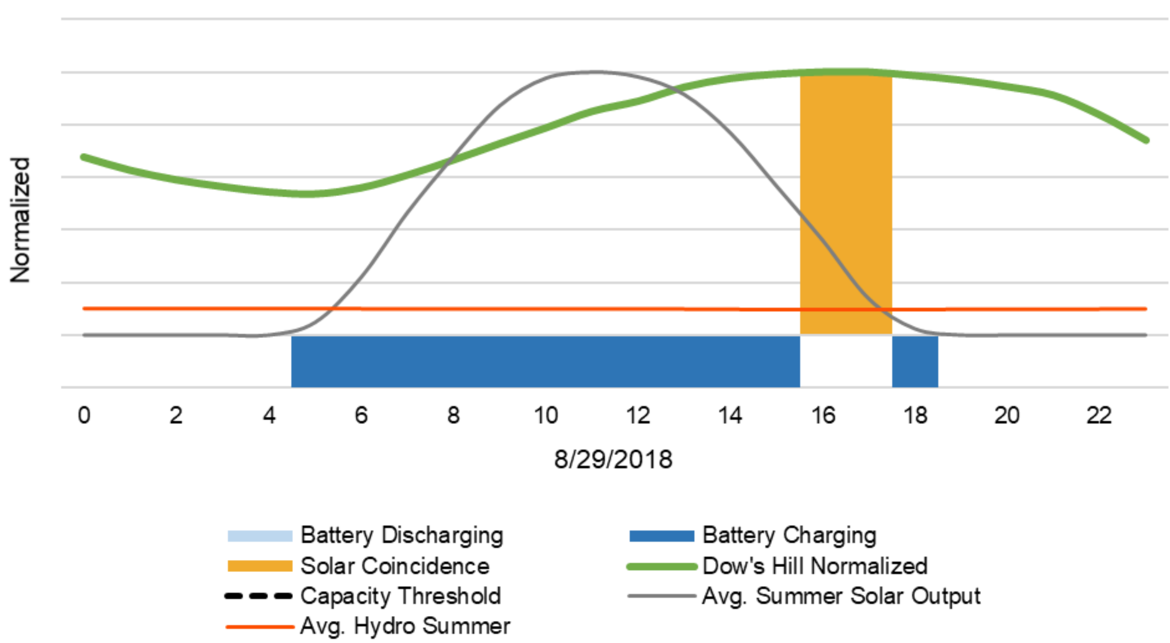
Source: Guidehouse, EDC data

Figure E-23. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Bow Bog (Non-Bulk)



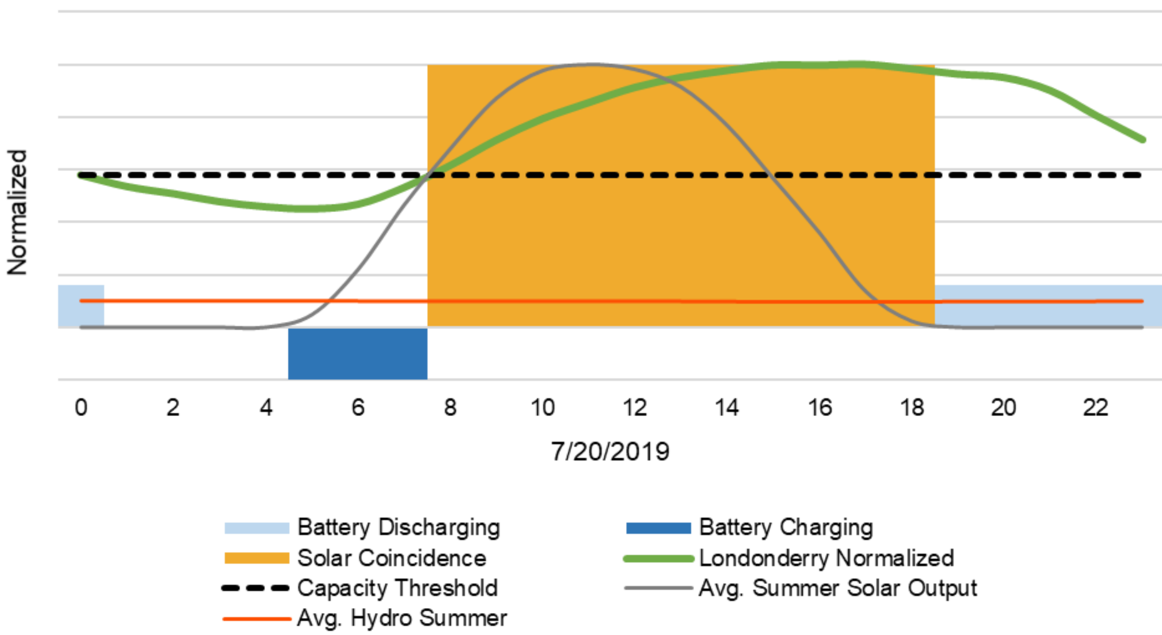
Source: Guidehouse, EDC data

Figure E-24. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Dow's Hill (Bulk)



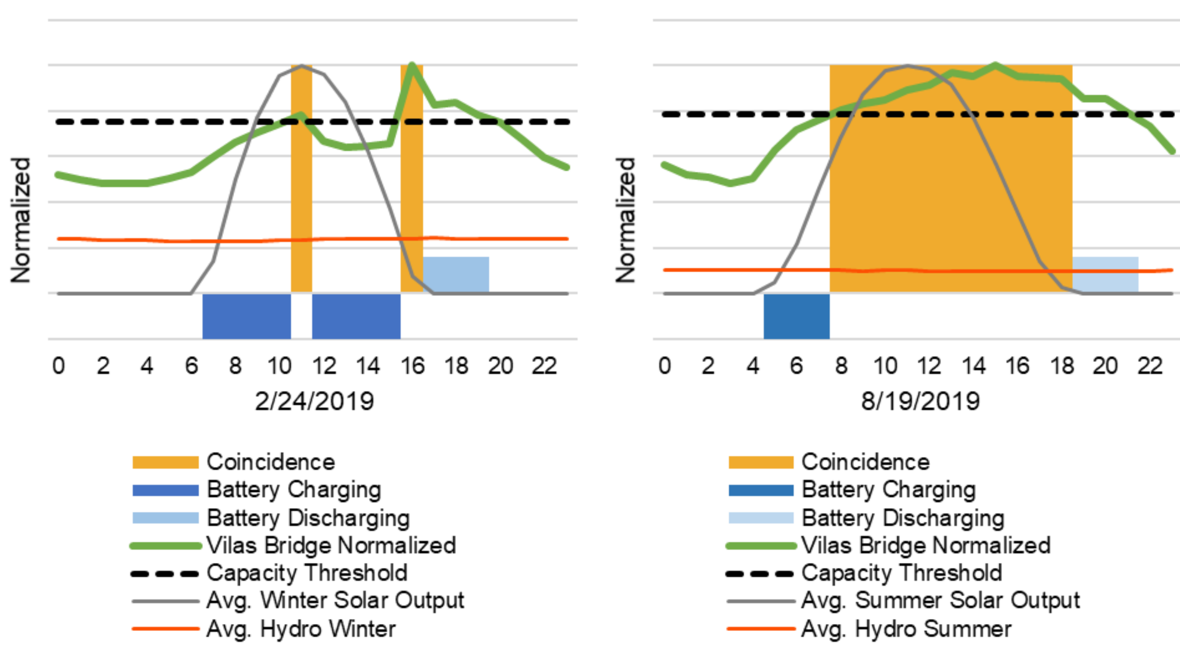
Source: Guidehouse, EDC data

Figure E-25. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Londonderry (34.5 kV)



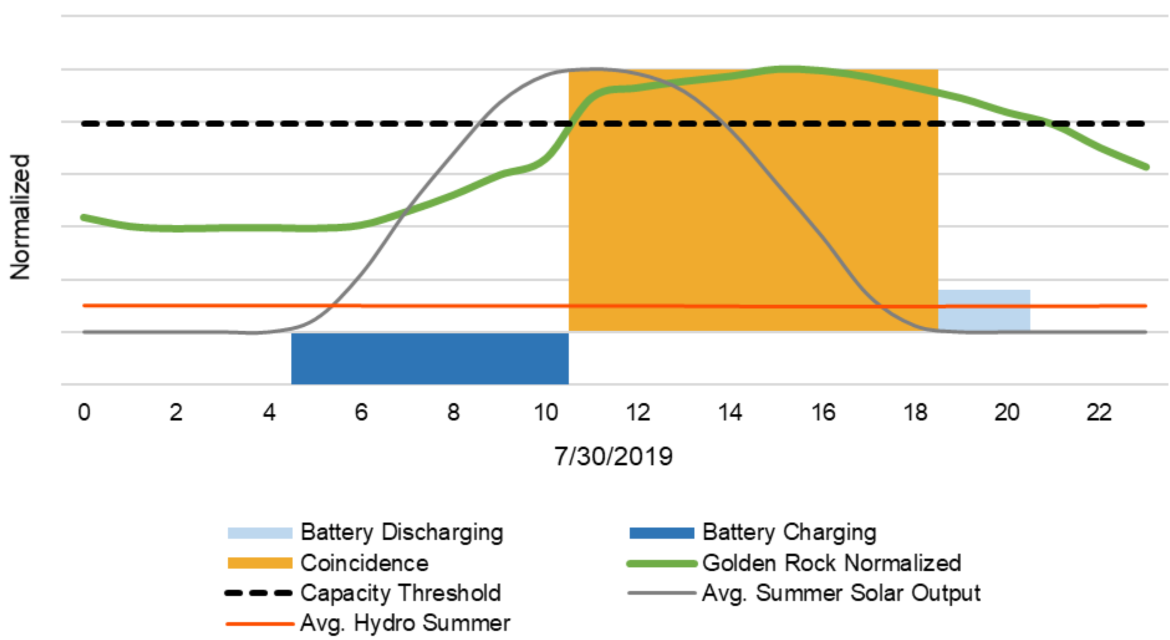
Source: Guidehouse, EDC data

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

1. New Hampshire NEM Order
2. New Hampshire LVDG Order approving study scope and timeline
3. New Hampshire VDER Order approving study scope and timeline
4. Eversource current planning criteria
5. Unitil current planning criteria
6. Liberty current planning criteria
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Appendix H. List of Figures and Tables

List of Figures

Figure **Page**

Figure 1. Regulatory Context 3
Figure 2. LVDG Analysis Timeframe 6
Figure 3. EDC Franchise Service Territories 7
Figure 4. Solar Irradiance and Hydro Sites in New Hampshire 9
Figure 5. Solar PV plus Storage Diagram 10
Figure 6. Cooling Degree Days vs. Coincident Summer Peak Load After Adding Back in Peak Load Reductions from EE (2006-2018) 13
Figure 7. High Case – Load Impact from Low Energy Efficiency Penetration 16
Figure 8. High Case – Load Impact from Aggressive EV Growth 17
Figure 9. Eversource Load Forecast (Base, Low, High) 18
Figure 10. Liberty Load Forecast (Base, Low, High) 19
Figure 11. Unitil Load Forecast (Base, Low, High for Seacoast and Capital Regions) 20
Figure 12. Forward-Looking Capacity Deficiencies by EDC 22
Figure 13. Historical Location Capacity Deficiencies – Eversource 27
Figure 14. Forward-Looking Location Capacity Deficiencies – Eversource 28
Figure 15. Historical Location Capacity Deficiencies – Liberty 28
Figure 16. Forward-Looking Location Capacity Deficiencies – Liberty 29
Figure 17. Historical Location Capacity Deficiencies – Unitil 29
Figure 18. Forward-Looking Location Capacity Deficiencies – Unitil 30
Figure 19. Bulk Substation Capacity Deficiencies – Eversource 30
Figure 20. Non-Bulk Substation Capacity Deficiencies – Eversource 31
Figure 21. Circuit Capacity Deficiencies – Eversource 31
Figure 22. Selected Locations Capacity Deficiencies – Liberty 32
Figure 23. Selected Locations Capacity Deficiencies – Unitil 32
Figure 24. Capital Investment Over Time for Selected Locations Across all EDCs 35
Figure 25. Low Load Forecast Capital Costs by Year of Investment Need 37
Figure 26. Base Load Forecast Capital Costs by Year of Investment Need 37
Figure 27. High Load Forecast Capital Costs by Year of Investment Need 38
Figure 28. RECC Avoidance Value 41
Figure 29. Total Annual Avoidance Value – Pemi Substation (Bulk) 43
Figure 30. Annual Avoidance Benefit – Pemi Substation (Bulk) 45
Figure 31. Total Annual Avoidance Value – Dow's Hill Substation (Bulk) 45
Figure 32. Annual Avoidance Value– Dow's Hill Substation (Bulk) 46
Figure 33. Marginal Load Buckets (MW) – Pemi Substation (Bulk) 50
Figure 34. Hourly Avoidance Value and Capacity Deficiency – Pemi Substation (Bulk) 51
Figure 35. Number of Hours with Capacity Deficiency – Pemi Substation (Bulk) 52
Figure 36. Seasonal Deficit Analysis – Pemi Substation (Bulk) 52
Figure 37. Marginal Load Buckets (MW) – Pemi Substation (Bulk) 53

Figure 38. Pemi Hourly Analysis for All Hours of Year 53
Figure 39. Number of Hours with Capacity Deficiency – Portsmouth Substation (Bulk) 54
Figure 40. Seasonal Deficit Analysis – Portsmouth Substation (Bulk) 54
Figure 41. Marginal Load Buckets (MW) – Portsmouth Substation (Bulk) 55
Figure 42. Portsmouth Hourly Analysis for All Hours of the Year 55
Figure 43. Peak Day Load for Five Example Locations 61
Figure 44. Average Hourly Profile by Month – Pemi Substation (Bulk) 62
Figure 45. Average Hourly Profile by Month – Portsmouth Substation (Bulk) 63
Figure 46. Location Selected for Solar PV Configurations 64
Figure 47. Average Summer Production by Solar Array Configuration Type 65
Figure 48. Peak Day Summer Production by Solar Array Configuration Type 65
Figure 49. Average Winter Production by Solar Array Configuration Type 66
Figure 50. Peak Day Winter Production by Solar Array Configuration Type 66
Figure 51. Representative Solar PV Production Profiles – Normalized Fixed 67
Figure 52. Hydroelectric Production Analysis 68
Figure 53. Summer Average Hydro Production Profiles 69
Figure 54. Winter Average Hydro Production Profiles 69
Figure 55. Annual Hourly Profile – Pemi Substation (Bulk) 70
Figure 56. Seasonal Capacity Deficiencies – Pemi Substation (Bulk) 71
Figure 57. Solar Mapping – Pemi Substation 71
Figure 58. Solar Coincidence Analysis – Fixed Axis: 180° and 270° – Pemi Substation 72
Figure 59. Solar plus Storage Charging Analysis – Pemi Substation (Bulk) 73
Figure 60. Solar, Storage, Hydro Coincidence Analysis – Pemi Substation 74
Figure 61. Annual Hourly Profile – Portsmouth Substation (Bulk) 75
Figure 62. Seasonal Capacity Deficiencies – Portsmouth Substation 75
Figure 63. Solar Coincidence Analysis – Portsmouth Substation (Bulk) 76
Figure 64. Solar plus Storage Charging Analysis – Portsmouth Substation (Bulk) 77
Figure 65. Solar, Storage, and Hydro Coincidence Analysis – Portsmouth 77
Figure 66. Locations with Summer and Winter Peaks 78
Figure 67. Locations with Summer Peaks Only 79

Figure A-1. Coincident Summer Peak (MW) vs. Total Real Peal Income (1991-2018) A-1
Figure A-2. Coincident Summer Peak After Adding Back in Peak Load Reductions from EE vs. Total Real Personal Income (2006-2018) A-2
Figure A-3. Coincident Summer Peak (MW) vs. Statewide Population (1991-2018) A-2
Figure A-4. Coincident Summer Peak (MW) vs. Real Gross State Product (1991-2018) A-3
Figure D-1. Annual Avoidance Value – Madbury ROW Circuit (34.5 kV) D-1
Figure D-2. Local Avoided Annual Value – Madbury ROW Circuit (34.5 kV) D-2
Figure D-3. Number of Hours with Capacity Deficiency – Madbury ROW Circuit (34.5 kV) D-2
Figure D-4. Seasonal Capacity Deficiency Analysis – Madbury ROW Circuit (34.5 kV) D-3

Figure D-5. Marginal Load Buckets (MW) – Madbury ROW Circuit (34.5 kV) D-3
Figure D-6. Hourly Analysis for All Hours of Year – Madbury ROW Circuit (34.5 kV) . D-4
Figure D-7. Annual Avoidance Value – Mount Support Substation (Bulk) D-4
Figure D-8. Local Avoided Annual Value – Mount Support Substation (Bulk) D-5
Figure D-9. Number of Hours with Capacity Deficiency – Mount Support Substation (Bulk) D-5
Figure D-10. Seasonal Capacity Analysis – Mount Support Substation (Bulk) D-6
Figure D-11. Marginal Load Buckets (MW) – Mount Support Substation (Bulk) D-6
Figure D-12. Hourly Analysis for All Hours of Year – Mount Support Substation (Bulk) D-7
Figure D-13. Annual Avoidance Value – Kingston Substation (Bulk) D-7
Figure D-14. Local Avoided Annual Value – Kingston Substation (Bulk) D-8
Figure D-15. Number of Hours with Capacity Deficiency – Kingston Substation (Bulk) D-8
Figure D-16. Seasonal Capacity Deficiency Analysis – Kingston Substation (Bulk) D-9
Figure D-17. Marginal Load Buckets (MW) – Kingston Substation (Bulk) D-9
Figure D-18. Hourly Analysis for All Hours of Year – Kingston Substation (Bulk) D-10
Figure E-1. Average Hourly Profile by Month – Madbury ROW Circuit (34.5 kV) E-1
Figure E-2. Average Hourly Profile by Month – Mount Support Substation (Bulk) E-2
Figure E-3. Average Hourly Profile by Month – Kingston Substation (Bulk) E-3
Figure E-4. Capacity Deficiencies – Madbury ROW Circuit (34.5 kV) E-4
Figure E-5. Summer Peak Day Load – Madbury ROW Circuit (34.5 kV) E-5
Figure E-6. Capacity Deficiencies – Madbury ROW Circuit (34.5 kV) E-5
Figure E-7. Solar Coincidence and Solar plus Storage Charging Analysis – Madbury ROW Circuit (34.5 kV) E-6
Figure E-8. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Madbury Circuit (34.5 kV) E-7
Figure E-9. Capacity Deficiencies – Mount Support Substation (Bulk) E-8
Figure E-10. Peak Day Load – Mount Support Substation (Bulk) E-9
Figure E-11. Solar Coincidence and Solar plus Storage Charging Analysis – Mount Support Substation (Bulk) E-9
Figure E-12. Solar Coincidence and Solar plus Storage plus Hydro – Mount Support Substation (Bulk) E-10
Figure E-13. Capacity Deficiencies – Kingston Substation (Bulk) E-11
Figure E-14. Peak Day Load – Kingston Substation (Bulk) E-12
Figure E-15. Solar Coincidence and Solar plus Storage Charging Analysis – Kingston Substation (Bulk) E-12
Figure E-16. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Kingston Substation (Bulk) E-13
Figure E-17. Solar Coincidence and Solar plus Storage plus Hydro Analysis – South Milford E-14
Figure E-18. Solar Coincidence and Solar plus Storage plus Hydro Analysis – Monadnock E-14
Figure E-19. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – East Northwood (Non-Bulk) E-15

Figure E-20. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Rye (Non-Bulk) E-15
Figure E-21. Solar Coincidence and Solar plus Storage plus Hydro Charging Analysis – Bristol (Non-Bulk)....E-16
Figure E-22. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – North Keene (12.47 kV) E-16
Figure E-23. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Bow Bog (Non-Bulk) E-17
Figure E-24. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Dow's Hill (Bulk)....E-17
Figure E-25. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Londonderry (34.5 kV) E-18
Figure E-26. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Vilas Bridge (Non-Bulk)....E-18
Figure E-27. Solar Coincidence and Solar plus Storage Charging plus Hydro Analysis – Golden Rock (Bulk)....E-19

List of Tables

Table ....Page
Table 1. EDC Statistics 8
Table 2. Number of Distribution Substation and Lines 11
Table 3. Summary of EDC Base Forecast Methodology 15
Table 4. Energy Efficiency Forecast.... 15
Table 5. Summary of EDC High Load Forecast Methodology.... 16
Table 6. EVs Load Forecast.... 17
Table 7. Summary of EDC Low Load Forecast Methodology 18
Table 8. EDC Planning Criteria 21
Table 9. Base Case Violations (Capacity Deficiencies).... 23
Table 10. Summary of Historical Projects 25
Table 11. Locations Selected for In-Depth Analysis.... 26
Table 12. Capital Investment by Location 35
Table 13. Summary of Selected Locations Load Forecast Scenarios 36
Table 14. Revenue Requirement and RECC Inputs.... 40
Table 15. Revenue Requirement by Location 42
Table 16. Pemi Substation (Bulk) Yearly Economic Analysis- Example Calculations 43
Table 17. Total Annual Avoidance Value by Location and Load Forecast 47
Table 18. Annual Avoidance Value per kW by Location and Load Forecast.... 48
Table 19. Hour of Day Weighting Example Calculation – Pemi Substation (Bulk) 50
Table 20. Hourly Avoided Cost Analysis Summary.... 56
Table 21. Hourly Avoided Cost Detailed Results by Location (Selected Locations 1-8 on 1st page and 9-16 on 2nd page).... 57
Table 22. Summary of Locational Peak Load at 16 Selected Locations 61
Table 23. Solar PV Configurations Considered.... 63
Table 24. Annual Load Profile and Capacity Threshold – Pemi Substation (Bulk).... 70
Table 25. Annual Load Profile and Capacity Threshold – Portsmouth Substation 75

Table B-1. Complete List of Capacity Deficiencies by Location B-1
Table E-1. Annual Load Profile and Capacity Threshold – Madbury ROW Circuit (34.5 kV)..E-4
Table E-2. Annual Load Profile and Capacity Threshold – Mount Support Substation (Bulk)..E-8
Table E-3. Annual Load Profile and Capacity Threshold – Kingston Substation (Bulk)...E-11

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